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June 30, 2020

—Via Electronic Filing—

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

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

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Supplement to its 2020-2034 Upper Midwest Integrated Resource Plan to the Minnesota Public Utilities Commission as required by its November 12, 2019 ORDER SUSPENDING PROCEDURAL SCHEDULE AND REQUIRING ADDITIONAL FILINGS and subsequent Notices of Extension in the above-referenced docket.

The plan we propose with this Supplement continues to chart a path toward achieving some of the most ambitious carbon reduction goals of any utility in the U.S. – an 80 percent carbon reduction from 2005 levels by 2030 and 100 percent carbon-free energy by 2050.

This Supplement provides a full refresh of our modeling results, including analysis using the new EnCompass model and updates to our inputs, assumptions and modeling approaches, responsive to feedback and direction from the Commission, Department of Commerce, and stakeholders. The Supplement Preferred Plan resulting from this substantial additional analysis continues to support the core components of the Preferred Plan that resulted from our initial analysis in 2019, with some modifications.

Specifically, our Supplement Preferred Plan proposes the following key actions:

- Retiring all of our coal generation by 2030, and reducing operations at some units prior to retirement;
- Extending the life of our Monticello plant to 2040;
- Adding nearly 6,000 MW of new renewables to our system within the planning period;
- Adding substantial demand-side management, including the addition of 400 MW of demand response by 2023, and average annual energy efficiency savings of over 780 gigawatt hours;
- Adding firm peaking resources as needed in the latter years of the plan, while leaving the door open for new technologies that may be available at that time to meet grid needs.

We note that the plan we propose with this Supplement is also directionally consistent with core components of our COVID-19 Relief and Recovery Plan, submitted June 17, 2020 in Docket No. E,G999/CI-20-492.

In addition to the main body of our document – which addresses our Supplement Preferred Plan and modeling approach that led to its development – we have also included several attachments that provide additional context for our plans and how we will achieve them. These include:

- Attachment A: Contains additional detail and context regarding our modeling assumptions, approaches, results, and implementation.
- Attachment B: Our revised Renewable Energy Standard and Solar Rate Impact Report, per the Commission's November 12, 2019 Order.
- Attachment C: Describing our commitment to workforce inclusion and diversity, and achieving an equitable transition to our clean energy future
- Attachment D: The CapX2020 utilities' request to MISO for an integrated transmission plan that addresses the utilities 2030 goals, and the CapX2050 Vision Report
- Attachment E: A summary of the Center of Energy & Environment's Host Community Impact Study, addressing the impact of baseload generation plant retirement on their host communities.
- Attachment F: An EnCompass model technical whitepaper provided by its vendor, Anchor Power Solutions.

We look forward to continuing the conversation regarding this Resource Plan with the Commission, stakeholders, and our communities.

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.

Not Public data included in this filing is limited to Attachment A, Section VII: Black Start. This Attachment contains data regarding forecast investments and information that could be used to identify our black start units and their capabilities. 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. This information also is security information as defined by Minn. Stat. § 13.37(1)(a) because it could be improperly used by someone to harm the electric grid.

Copies of the filing have been served on Commission Staff, Department of Commerce Staff, 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/

GREG P. CHAMBERLAIN
REGIONAL VICE PRESIDENT
REGULATORY & GOVERNMENT AFFAIRS

Enclosures
c: Service List

UPPER MIDWEST INTEGRATED RESOURCE PLAN
2020-2034

Supplement

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

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2020-2034 UPPER MIDWEST INTEGRATED RESOURCE PLAN SUPPLEMENT

SECTION 1: SUPPLEMENT EXECUTIVE SUMMARY

Our initial filing in July of 2019 – which accounted for more variables and changes than any other previous Xcel Energy resource plan – proposed a resource mix that achieved some of the most ambitious carbon reduction goals of any utility in the United States. The Supplement Preferred Plan proposed in this update achieves a similar result through retirement of our coal fleet, extension of nuclear, significant renewable additions, demand-side management, including both energy efficiency (EE) and demand response (DR), and a mix of load-supporting, firm peaking resources.

After our July 2019 filing, the Commission directed the Company to conduct additional modeling analysis in its November 12, 2019 Order in this docket. Specifically, the Commission directed the Company to provide supplemental information and modeling including a revised Renewable Energy Standard Rate Impact Report, further modeling of various sizes for our proposed new Sherco combined cycle generator, and an analysis of storage technology combined with renewable generation sources.

We have now completed this work. In preparing this Supplement, the Company conducted extensive additional capacity expansion modeling using both Strategist, a tool we have historically relied on, and EnCompass, a new tool that provides the additional capability of modeling our system on an hourly basis. In addition to providing the supplemental information required by the Commission, we also adjusted our modeling to address concerns some parties raised with the modeling used to create our Initial Preferred Plan from our July 2019 filing.

Based on this additional modeling in both EnCompass and Strategist, we developed our Supplement Preferred Plan, which shares the same key elements as the Initial Preferred Plan. Specifically, our Supplement Preferred Plan continues to include early retirements of our coal units, extension of the Monticello license, and significant renewable additions after 2024. We believe the Supplement Preferred Plan best positions the Company to achieve our ambitious carbon-reduction goals while maintaining a reliable system and keeping our customers' bills low and, therefore, is in the public interest and should be approved.

A. Supplement Preferred Plan

Our Supplement Preferred Plan maintains the Company's vision for the future of our system that was included in our Initial Preferred Plan. Specifically, our Supplement Preferred Plan proposes the following actions:

- ***Coal Resources –*** Retire our last two units several years early: King in 2028 and Sherco 3 by 2030. Additionally, continue our plan to retire Sherco 1 and 2 in 2026 and 2023, respectively, and implement reduced, seasonal dispatch of Sherco Unit 2 until its retirement.
- ***Nuclear Resources –*** Operate our Monticello unit through 2040 (10 years longer than its current license) and operate both Prairie Island units at least through the end of their current licenses (PI Unit 1 to 2033 and PI Unit 2 to 2034).[1]
- ***Renewable Resources –*** Add over 3,500 MW of utility scale solar by 2030 (starting in 2025) and approximately 2,250 MW of wind by 2034.
- ***Combined Cycle Resources –*** Build, own and operate the approximately 800 MW Sherco CC which is a firm dispatchable, load-supporting resource.
- ***Firm Load Supporting Resources –*** Starting in 2030, add approximately 2,600 MW of cumulative firm peaking, load-supporting resources by 2034. Depending on the technology available, the cost of resources, and Commission preferences, we believe these additions could include energy storage, DR, or hydrogen, among other alternatives.
- ***Demand Side Management (DSM) –*** Include EE programs that achieve savings levels ranging from 2 to 2.5 percent annually, 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.

The Supplement Preferred plan continues to achieve our carbon reduction goals while maintaining reliability and affordability as discussed below.

We also recognize that our proposed plan will have 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

[1] 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.

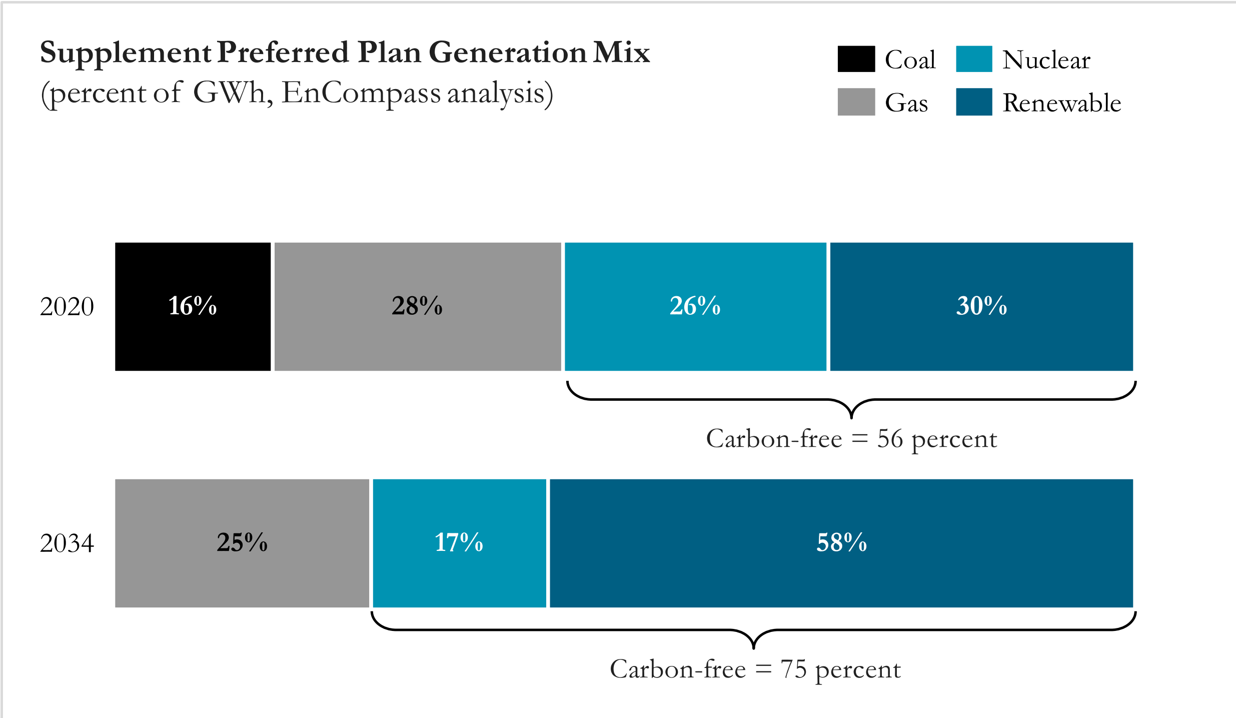
our communities, policymakers, stakeholders and employees to successfully manage this clean energy transition.

We note that, on June 17, 2020, in Docket No. E,G999/CI-20-492, in response to the Commission's Notice of Reporting Required by Utilities, the Company filed a Report laying out a number of proposed investments the Company could make to assist in Minnesota's economic recovery from the COVID-19 Pandemic (June 17 Relief and Recovery Report). These investments included a solicitation for repowering existing wind resources as well as the addition of up to 460 MW of solar at our Sherco site. Although these investments are not specifically included in the Supplement Preferred Plan, we believe they are consistent with the direction we have set out here as well as the policy direction from the Commission and environmental goals of the state. We look forward to further discussions regarding those proposed investments and, if approved, how they can be integrated into our Supplement Preferred Plan.

1. *The Supplement Preferred Plan Meets our Ambitious Carbon Goals*

The fleet transformation reflected by the Supplement Preferred Plan will achieve a substantial reduction in CO_2 emissions, meeting our corporate goal of an 80 percent reduction from 2005 levels by 2030 ("80 by 30") and setting the Company on a path to achieve 100 percent carbon-free generation by 2050. Nuclear generation continues to be a cornerstone of our plan to serve customers with increasingly clean energy. Figure 1-1 below compares the Company's current generation mix to the Supplement Preferred Plan's projected generation mix by 2034 and their respective percentages of carbon-free generation.

Figure 1-1: Supplement Preferred Plan Generation Mix 2020-2034 (GWh)



2. *The Supplement Preferred Plan Preserves System Reliability*

Throughout this process, we have taken steps to ensure that we can meet our carbon reduction goals while preserving the reliability of the system. When we developed our Initial Preferred Plan, we recognized that, as we added increasing variable renewable resources to our generation mix, maintaining reliability would become increasingly complex. Thus, we developed a "Reliability Requirement" to include in our Strategist modeling, to account for the fact that Strategist was incapable of modeling reliability needs every hour of the year. This resulted in the addition of 1,700 MW of firm peaking resources in the out years of the Initial Preferred Plan.

The EnCompass modeling results provided in this Supplement validate our decision to include the Reliability Requirement with the Initial Preferred Plan. EnCompass selected approximately 2,600 MW of firm, peaking resources[2] in 2030-2034 through its optimization; in other words, we did not force the model to include these resources, but it selected them as part of a least-cost and reliable portfolio.

[2] Because these additions do not occur for more than ten years, we are intentionally leaving them technology neutral, recognizing that they could be non-emitting resources like storage or DR.

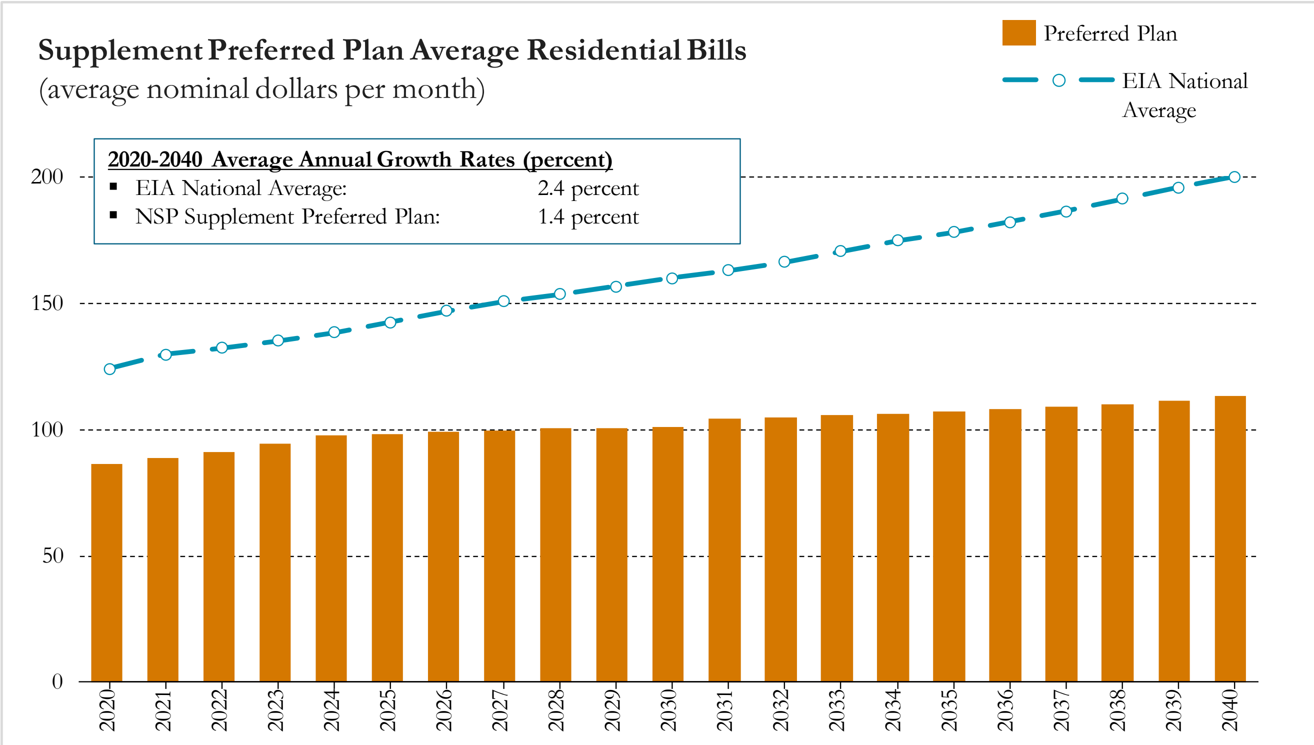
We also continue to include the planned Sherco CC in the Supplement Preferred Plan to support both the addition of renewable resources in the mid-2020s,our black start plan, and other critical operational reliability needs. In addition, our Supplement Preferred Plan includes cost assumptions that reflect an estimate of the amount of investment required to extend the lives of our existing black start generating facilities beyond their existing planned retirement dates to 2030. We expect that, depending on the specific resource type, some of the firm peaking resources projected to be added between 2030 and 2034 could also be available to provide black start services.

3. *The Supplement Preferred Plan Maintains Affordable Customer Bills*

We also recognize that the achievement of our carbon reduction goals will depend on our ability to keep bills affordable. We believe that our Supplement Preferred Plan accomplishes this by keeping average residential customer bills well below the national average and at a rate of growth below inflation, and nearly a full percentage point below the national average growth rate over the planning period. And, we believe technological improvements will continue to drive the costs of renewables and storage down.

As shown in the Figure below, NSP System residential customers – on average – pay substantially less per month than the national average. In the early years of the forecast, this difference is attributable to lower than average electricity consumption, driven partially by our anticipated EE achievements. We also expect our average bill levels will grow more slowly than the national average, by approximately a full percentage point per year.

Figure 1-2: Systemwide Supplement Preferred Plan Average Residential Bills



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 purchased power agreement (PPA) expirations come at some cost. But we believe that cost – which continues to keep average residential customer bills well below the national average - – is both modest and appropriate compared to the substantial benefits we describe here.

B. Modeling Tools and Changes

As noted above, in preparing this Supplement and choosing our Supplement Preferred Plan, we conducted modeling using both the EnCompass tool we intend to use going forward, and the Strategist tool we have historically used. And in addition to conducting modeling using EnCompass, since filing our initial Resource Plan in July 2019, the Company has made several changes to its modeling approaches, inputs, and assumptions to respond to feedback received in the docket.

1. Modeling Tools

As discussed above, we used both the Strategist and EnCompass models for this Supplement. Because the two tools have different capabilities—EnCompass is able to model our system on an hourly chronological basis, and Strategist is not—the modeling results from each tool are, unsurprisingly, different. Because we believe the more granular forecasting capabilities of EnCompass provide us a more accurate view of our future energy and capacity needs, we primarily used those modeling results to create our Supplement Preferred Plan.

The updated results from our Strategist modeling, however, provide a valuable comparison, and they confirm the Company's overall direction reflected in the Supplement Preferred Plan. Under both models, our plan for early baseload retirements and extending Monticello provides a clear path for achieving an 80 percent reduction in carbon emissions from 2005 levels by 2030. Relatedly, both show significant savings when considering CO_2 costs and additional potential savings that will depend on a future decision on the extension of Prairie Island's operating license.

That is not to say the models entirely align. The specific longer-term projected resource additions differ somewhat between the two but are directionally consistent – both show significant renewable additions and a need for firm dispatchable resources to support that variable renewable generation. We believe, therefore, that the results of our updated Strategist modeling support and validate the Supplement Preferred Plan modeled using EnCompass.

2. Modeling Changes

As noted above, the Company has made several changes to its modeling approaches, inputs, and assumptions since our initial filing. Some of these changes were implemented based on feedback from the Commission and discussions with the Department of Commerce (DOC) and other stakeholders. Other updates reflect the passage of time and availability of more recent input and assumptions source material.

In general, these changes fall into three broad categories: (a) changes to our modeling approach and constraints; (b) changes to market and technology assumptions; and (c) changes to assumptions regarding our Upper Midwest system's load and resources.

a. Changes to Modeling Approach and Constraints

The first category of adjustments includes major modeling approach changes. They are as follows:

- *Reliability Requirement Removed.* In this Supplement, we no longer include a Reliability Requirement in our modeling baseline; rather we allow the

EnCompass modeling to fully optimize a given portfolio without a "floor" of firm, dispatchable capacity.

- *Carbon constraint removed.* We no longer require all scenarios to meet the Company's 80 by 30 goal. By removing this modeling constraint, we can evaluate whether any of the baseload scenarios meet this goal based only on portfolio optimization.
- *Only online or approved resources included.* We no longer include any resources in our baseline that were not yet online or approved as of a January 31, 2020 resource lock-in date. This adjustment also means that we no longer include the selection of 1,200 MW of replacement wind (termed "no going back wind" in our initial filing) as a default assumption in our portfolio modeling.
- *Generic wind availability in early forecast years.* Given substantial ongoing transmission constraints in our MISO region, we did not make generic wind resources available for the model to select until 2026. This assumption reflects the current status of the MISO queue and our expectation that incremental greenfield wind will face significant barriers in the near term.
- *Market energy sales constraint.* We restricted market energy sales to no more than 25 percent of retail energy demand in EnCompass capacity expansion plan development, after early modeling indicated that EnCompass results were sensitive to technology cost and market assumptions. We then removed the sales limitation for the production costing runs conducted on each expansion plan scenario. We imposed this constraint to mitigate customer risk and limit the model from selecting incremental future resource additions largely based on market revenue rather than native load serving opportunities.

b. Changes to Market and Technology Inputs and Assumptions

The second category of adjustments and updates pertains to market and technology inputs and assumptions. These changes primarily update inputs to the latest vintages and modify assumptions to be more reflective of conditions in our system or region. Major changes include:

- *Updated technology cost assumptions*. We updated our wind, solar and battery cost assumptions using the *2019 Annual Technology Baseline* (ATB) data from the National Renewable Energy Laboratory (NREL). For wind and solar resources, these updates resulted in slightly lower assumed costs than we used in our initial filing while storage has higher costs. We also adjusted capacity factor estimates for both wind and solar resources to be more reflective of regional production trends. This resulted in lower assumed generic wind capacity factors and higher assumed generic solar capacity factors. Finally, in order to account for continuing transmission constraints in MISO West, we increased the assumed interconnection costs associated with generic renewables, to $500/kW from $400/kW previously for wind and $200/kW for solar from $140/kW.

- *Capacity accreditation updates*. We also modified our assumptions regarding capacity accreditation for wind and solar resources, based on the latest available guidance from MISO. In its 2020-2021 Wind and Solar Capacity Credit Report, MISO indicated that its latest wind effective load carrying capability (ELCC) for our Zone (Zone 1) is 16.7 percent, which is higher than the 15.6 percent assumption used in our initial filing. For solar, we aligned our accreditation assumptions with MISO's 2019 Transmission Expansion Plan (MTEP) study assumptions, which reflects a declining ELCC value as solar adoption in MISO increases. We model a 50 percent ELCC, consistent with current year MISO guidance, from 2020 to 2023. After that, ELCC steps down 2 percent per year through 2033, until it reaches and remains at 30 percent for the remainder of the modeling period.

c. Changes to Upper Midwest System Inputs and Assumptions

Finally, we made several modifications to assumptions around inputs specific to our system, either to update our approach and assumptions with more recent information, or to align with Commission and Department feedback.

- *Sherco 3 Retirement Date.* Per the Commission's direction, we have updated the Sherco Unit 3 baseline retirement date from 2040 to 2034, in order to align with its financial end of life.[3]
- *Seasonal Coal Dispatch.* We incorporated our seasonal coal dispatch plans for Sherco 2 and King into our Supplement modeling. As a result, these units do not run in spring and fall seasons through 2023, after which Sherco 2 retires and King operates on an economic basis until its retirement date per the given scenario.
- *Black Start.* Recognizing that black start capability is an essential attribute for our overall system reliability, we included placeholder black start capacity (and associated costs) in our modeling so that we may evaluate a capacity expansion portfolio that includes consideration of this future need.
- *Resource Baseline Updates.* We adjusted our baseline resource list where generating units have undergone status changes since our initial filing. Most notably, we

[3] As approved in our last *Annual Remaining Lives* filing (Docket No. E,G002/D-19-161).

model the Mankato Energy Center (MEC) units' PPAs according to their current expiration dates, and the Crowned Ridge Wind facility's size reduction – to 400 MW from its originally approved 600 MW –in response to significant transmission upgrade cost constraints.

- *Internal forecast updates*. We updated the vintages for our corporate load, distributed energy resource (DER) and electric vehicle forecasts. While electric vehicle markets in the Upper Midwest remain somewhat nascent and forecasts are subject to change, we have incorporated the Commission's feedback regarding historical lack of alignment amongst forecasts used in different filings. The forecasts we use in this Supplement are well now well aligned with those used in our latest Integrated Distribution Plan.

We note that the corporate forecasts underlying our Supplement modeling do not reflect potential effects of the COVID-19 pandemic and resulting recession on our energy demand. It is too early to know to what extent energy demand will decline in response – or the duration of these effects – but we continue to examine these changes.

C. Worker Transition Plans and Host Community Impacts

As noted above, the Supplement Preferred Plan we have proposed reflects a significant change in our generation fleet through coal retirements and significant renewable additions. We recognize that retirement of significant generation units, as proposed in this Supplement, 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. The Host Community Impact study conducted by Center for Energy and Environment (CEE) included with this Supplement provides further context and opportunities for engagement with our communities, employees, and stakeholders as we continue to work together on the clean energy transition.

We are dedicated to working with our employees, representative unions, communities, and stakeholders to manage community impacts throughout our clean energy transition. Our baseload generation plants are prominent places of employment and contributors to the property tax base in the host communities, which is why we focus our economic development efforts in locations where our current units will eventually be phased out. For example, since our last Resource Plan, in which we proposed to retire the Sherco 1 and 2 coal units in Becker, we have worked extensively with the local government, community stakeholders, and the state to draw new development to support the local economy. This includes a planned combined cycle generating unit at the Sherco site, the Northern Metal Recycling facility, and, prospectively a new

Google data center with energy matched by new renewable development on our system. In addition, we have proposed to add up to 460 MW of solar at the Sherco site.[4] This proposed investment will provide significant economic stimulus and jobs for the local economy and the state of Minnesota.

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 and union representatives to transition them to other Xcel Energy plants or areas of the company. While transition plans for impacted employees at our Sherco and King plants are still under development, we have done significant planning for the transition and have been in continued communications with plant employees. We expect that no Xcel Energy employee will be laid off as a result of the Sherco and King plant closures. Impacted workers will be able to leverage internal and external resources to upskill or reskill in order to transition into other positions in the Company. There will be opportunities for impacted employees at the plants within Xcel Energy, at locations nearby King and Sherco, or across the state of Minnesota.

We will continue developing plans for the transition at Sherco and King using the same general approach to workforce and community transition we used at other plants across our service territories. Community transition and solutions will be unique to each community and driven by the community and their vision for the future. Xcel Energy has a long history of partnering with communities we operate in to reach their vision.

CONCLUSION

Our Supplement Preferred Plan – which 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 – is in the public interest. It puts the Company on a path to transform its fleet in a planful, coordinated way while maintaining a balanced mix of diverse energy sources. 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 Supplement Preferred Plan is in the public interest and merits Commission approval.

[4] Docket No. E,G999/CI-20-492

SECTION 2: MODELING FRAMEWORK AND RESULTS

With the introduction of the EnCompass tool and its 8,760-hour modeling capabilities, the Company has undertaken significant updates to our modeling approach since our July 2019 filing. We have incorporated feedback from the Commission, Department and stakeholders, and worked to conduct robust modeling on our baseload scenarios to re-assess our Preferred Plan. This section describes our modeling approach, key updates to inputs and assumptions, and results of this extensive scenario and sensitivity modeling. Ultimately, our modeling findings lead us to conclude that Scenario 9 remains the basis of our Supplement Preferred Plan and represents a path forward to achieving our carbon reduction goals affordably and reliably.

A. Planning Objectives and Analysis Approach

While the Supplement has incorporated new modeling elements and updated assumptions, our core planning objectives have remained consistent relative to our initial filing. Figure 2-1, also included in our July 2019 filing, acts a reminder of the core planning objectives we consider. It is essential that we hold these factors – which are sometimes in tension with one another – in balance as we develop our analysis and select our Preferred Plan. Our initial filing included a Preferred Plan that achieved all these objectives. The Supplement Preferred Plan differs in some respects, particularly because we have introduced a new modeling tool – EnCompass – which enables more granular analysis of load and resource needs on an hourly basis. However, our modeling and scenario evaluation approach ensures that the Supplement Preferred Plan continues to achieve these planning objectives.

Figure 2-1: Xcel Energy Resource Integrated Resource Plan Objectives

In our initial filing, we used the Strategist capacity expansion model to assess fifteen different baseload coal and nuclear retirement scenarios and resulting future least-cost resource portfolios. Our Supplement Resource Plan analysis follows a similar overall modeling approach; we first analyzed fifteen baseload scenarios, developing capacity expansion plans and selecting the optimal portfolio based on cost, environmental, reliability and risk metrics. In addition to updating several assumptions and inputs in this Supplement, we have also incorporated the new EnCompass tool and its hourly chronological modeling capabilities. This tool allows more granular analysis of customer needs and resource capabilities across every hour of every day. Utilizing both Strategist and EnCompass, we examined our baseload scenarios and a wide range of sensitivities to ensure our Supplement Preferred Plan is reasonable and meets our planning objectives. We depict our modeling process in Figure 2-2 and describe each step and its outcomes further below.

Figure 2-2: Supplement Analysis Approach Framework

Pre-modeling	Baseload Scenario Modeling	Baseload Sensitivity Testing	Evaluation and Preferred Plan Selection	Preferred Plan Sensitivities
▪ Incorporate feedback ▪ Update previous inputs and assumptions ▪ Develop new inputs needed for revised analyses in Strategist and Encompass ▪ Update minimum system needs	For all 15 baseload scenarios: ▪ Refresh Strategist capacity expansion modeling ▪ Conduct EnCompass capacity expansion and production cost modeling ▪ Compare results from Strategist and EnCompass	For all 15 baseload scenarios, in both Strategist and EnCompass: ▪ Test standard sensitivities to evaluate how portfolios respond to price, load, and other factors ▪ Test "Futures" combination sensitivities	Using EnCompass outputs: ▪ Evaluate baseload scenarios on planning objective metrics (cost, environment, reliability, and risk) ▪ Select Preferred Plan	For Preferred Plan, test: ▪ Commission-ordered sensitivities ▪ Reliability testing on selected sensitivities using EnCompass 8,760 hourly modeling

B. Pre-Modeling

As a first step in our Supplement process, we set out to catalogue the feedback received on our initial filing and identify valuable input and assumption updates and new inputs we may need for the EnCompass modeling process. We also updated our minimum system needs assessment based on updated load, MISO planning reserve and capacity accreditation, and the latest existing or approved resource information. This work established the baseline and key inputs upon which our capacity expansion modeling develops optimal portfolios for each scenario.

1. *Incorporating Feedback and Other Input and Assumption Updates*

Since filing our initial Upper Midwest Resource Plan in July 2019, the Company has made several changes to its modeling approaches, inputs, and assumptions. Some of these changes in modeling approaches were implemented based on discussions with the Department of Commerce (DOC or Department), and feedback from the Commission and stakeholders. Others reflect the passage of time and availability of more recent input and assumptions source material. In general, we can group these changes into three broad categories: changes to our modeling approach (and specifically constraints imposed in modeling); changes to market and technology assumptions; and changes to assumptions regarding our Upper Midwest system's load and resources. We address major changes in each of these categories below, and more complete details are available in Attachment A, Section IV: Modeling Assumptions and Inputs.

a. Modeling Approach and Constraints

The Company has undertaken several major modeling approach changes in response to the Commission and Department feedback. The most substantial of these is, of course, the introduction of the EnCompass model. In the course of discussion regarding supplemental analysis – and specifically addressing the inclusion of a Reliability Requirement in our initial modeling – the Commission directed us to undertake hourly chronological modeling analysis of our proposed portfolio in order to better evaluate reliability and resource attribute concerns. We also removed several other modeling constraints in response to Commission and Department feedback. These changes are listed below:

- *Reliability Requirement Removed.* As noted above, our initial modeling included a Reliability Requirement, which ensured that sufficient firm, dispatchable capacity to meet winter peaking needs always remained on our system. In this Supplement, we no longer include a Reliability Requirement in our modeling baseline; rather, we allow the EnCompass model to fully optimize a given portfolio without such a "floor" of firm, dispatchable capacity.
- *Carbon constraint removed.* We no longer require all scenarios to meet the Company's 80 by 30 goal. By removing this modeling constraint, we can evaluate whether any of the baseload scenarios meet this goal based only on portfolio optimization.
- *Only online or approved resources included.* We no longer include any resources in our baseline that were not yet online or approved as of a January 31, 2020 resource lock-in date.[5] This adjustment also means that we no longer include the selection of 1,200 MW of replacement wind (termed "no going back wind" in our initial filing) as a default assumption in our portfolio modeling.

We also used new modeling constraints and approaches in Supplement modeling development, after consultation with the Department, to best address operational realities in the MISO market and our system:

- *Generic wind availability in early forecast years.* Given substantial ongoing transmission constraints in our MISO region, we did not make generic wind

[5] While there are some contracts that have been executed and approved in the interim between January 31 and the date of filing, accredited capacity for these resources is not substantial, and we do not believe it would materially affect portfolio modeling outcomes.

resources available for the model to select until 2026. This assumption reflects the current status of the MISO queue and our expectation that incremental greenfield wind will face significant barriers in the near term.

- *Market energy sales constraint*. We restricted market energy sales to no more than 25 percent of retail energy demand in EnCompass capacity expansion plan development, after early modeling indicated that EnCompass results were sensitive to technology cost and market assumptions. We then removed the sales limitation for the production costing runs conducted on each expansion plan scenario. We imposed this constraint to mitigate customer risk and limit the model from selecting incremental future resource additions based on market revenue rather than native load serving opportunities.

For both of these model limitations, however, we examined their impact by testing alternate scenarios that relax these constraints.

b. Market and Technology Inputs and Assumptions

The second category of adjustments and updates pertains to market and technology inputs and assumptions. These primarily update inputs to the latest vintages of data and modify assumptions to be more reflective of conditions in our system or region. Major changes include:

- *Updated technology cost assumptions*. We updated our wind, solar and battery cost assumptions using the 2019 ATB from NREL. These updates resulted in slightly lower assumed costs for wind and solar resources than we used in our initial filing, while storage has slightly higher costs. We also adjusted capacity-factor estimates for both wind and solar resources to be more reflective of regional production trends. This resulted in lower assumed generic wind capacity factors and higher assumed generic solar capacity factors. Finally, in order to account for continuing transmission constraints in MISO West, we increased the assumed interconnection costs associated with generic renewables, to $500/kW from $400/kW for wind and $200/kW from $140/kW for solar.

- *Capacity accreditation updates*. We modified our assumptions regarding capacity accreditation for wind and solar resources based on the latest available guidance from MISO. In its 2020-2021 Wind and Solar Capacity Credit Report, MISO indicated that its latest wind ELCC for our Zone (Zone 1) is 16.7 percent, which is higher than the 15.6 percent assumption used in our initial filing. For solar, we have elected to align our accreditation assumptions with MISO's 2019 MTEP study assumptions, which reflects a declining ELCC value as solar adoption in MISO increases. We model a 50 percent ELCC, consistent with current year MISO guidance, from 2020 to 2023. After that, solar ELCC steps down 2 percent per year through 2033, until it reaches and remains at 30 percent for the remainder of the modeling period. We note that this is a relatively commonly employed assumption in other utilities' resource plans, both in MISO and in other regions.[6] That said, we have examined the effect of this assumption by modeling a sensitivity that maintains solar capacity accreditation at 50 percent throughout the planning period.

c. Upper Midwest System Inputs and Assumptions

Finally, we made several modifications to assumptions around inputs specific to our system, either to update our approach and assumptions with more recent information, or to align with Commission and Department feedback:

- *Sherco 3 Retirement Date.* Per the Commission's direction, we have updated the Sherco Unit 3 baseline retirement date from 2040 to 2034, in order to align with its financial end of life.[7]
- *Seasonal Coal Dispatch.* We incorporated our seasonal coal dispatch plans (recently approved by the Commission)[8] for Sherco 2 and King into our Supplement modeling. As a result, these units do not run in spring and fall seasons through 2023, after which Sherco 2 retires and King operates on an economic basis until its retirement date per the given scenario.
- *Black Start.* We noted in our July 2019 filing that system retirements within the planning period would affect our black start plans and that we may have to address this need prior to our next Resource Plan. While we continue to analyze alternatives, we know that black start capability is an essential attribute for system reliability; thus, we have included placeholder black start capacity (and associated costs) in our modeling so that we may evaluate a capacity expansion portfolio that includes consideration of this future need. We emphasize that this placeholder capacity does not represent a black start proposal; rather, it is for modeling purposes only.
- *Resource Baseline Updates.* We have adjusted our baseline resource list where generating units have undergone status changes since our initial filing. Most

[6] For example, DTE Energy, Indianapolis Power & Light and Dominion Virginia – among others – use declining solar ELCC in their resource plan modeling. Further, the California Public Utilities Commission uses a declining marginal ELCC for both their resource planning and resource adequacy proceedings. Please see Attachment A Section VI: Resource Attributes for further discussion.
[7] As approved in our last *Annual Remaining Lives* filing (Docket No. E,G002/D-19-161).
[8] Per Docket No. E-002/M-19-809.

notably, our proposed MEC acquisition was not approved last fall, and thus we now model MEC units' PPAs according to their current expiration dates. The Crowned Ridge Wind facility has undergone a size reduction – to 400 MW from its originally approved 600 MW, in response to significant transmission upgrade cost constraints. These and any other units with expired contracts have been modified in our baseline according to their status as of the January 31 resource lock-in date discussed above.

- *Internal forecast updates.* We updated the vintages for our corporate load, DER and electric vehicle forecasts. While electric vehicle markets in the Upper Midwest remain somewhat nascent and forecasts are subject to change, we have incorporated the Commission's feedback regarding historical lack of alignment amongst forecasts used in different filings. The forecast we use in this Supplement is well now well-aligned with those used in our latest Integrated Distribution Plan.

2. *Modeling Inputs for Use in EnCompass*

As noted above, the EnCompass hourly chronological modeling capabilities enable more robust system analysis – especially for production cost modeling – which requires us to adjust existing model inputs or develop new ones. For example, we have always used full 8,760-hour load shapes and renewable production profiles for modeling, but these inputs were simplified to typical weeks for use in Strategist. As EnCompass production cost modeling allows full hourly chronological analysis, we were able to use the shapes as originally provided for analysis conducted in that model. New data elements are largely related to thermal units and capture plant operational aspects, such as minimum up and down times, mean time to repair after a forced outage, ramping rates, and costs or fuel consumption associated with startup. These inputs were not previously relevant because Strategist's load duration curve modeling does not examine the effects of hour-to-hour changes for any specific plant.

3. *Re-assessing Minimum System Needs*

After incorporating the substantial edits discussed above, we began our last step in the pre-modeling process: reassessing our Minimum System Needs. This analysis helps us evaluate the total customer load and energy demand we anticipate through the planning period, and what resources we already have existing or approved on our system to serve them. We describe these updates at a high level below and provide further detail in Attachment A, Section I: Minimum System Needs. Forecasting methods for customer demand specifically is described further in Attachment A, Section II: Load Forecast.

a. Load and Energy Demand

As discussed in our initial filing, we use econometric analysis and historical actual coincident net peak demand data to develop a corporate forecast for system peak demand and energy requirements. These corporate forecasts are subsequently adjusted for Resource Plan modeling, as described further below. For the purposes of this Supplement, we have updated our load and energy demand forecasts from the fall 2018 vintage used in our initial filing to our fall 2019 vintage.

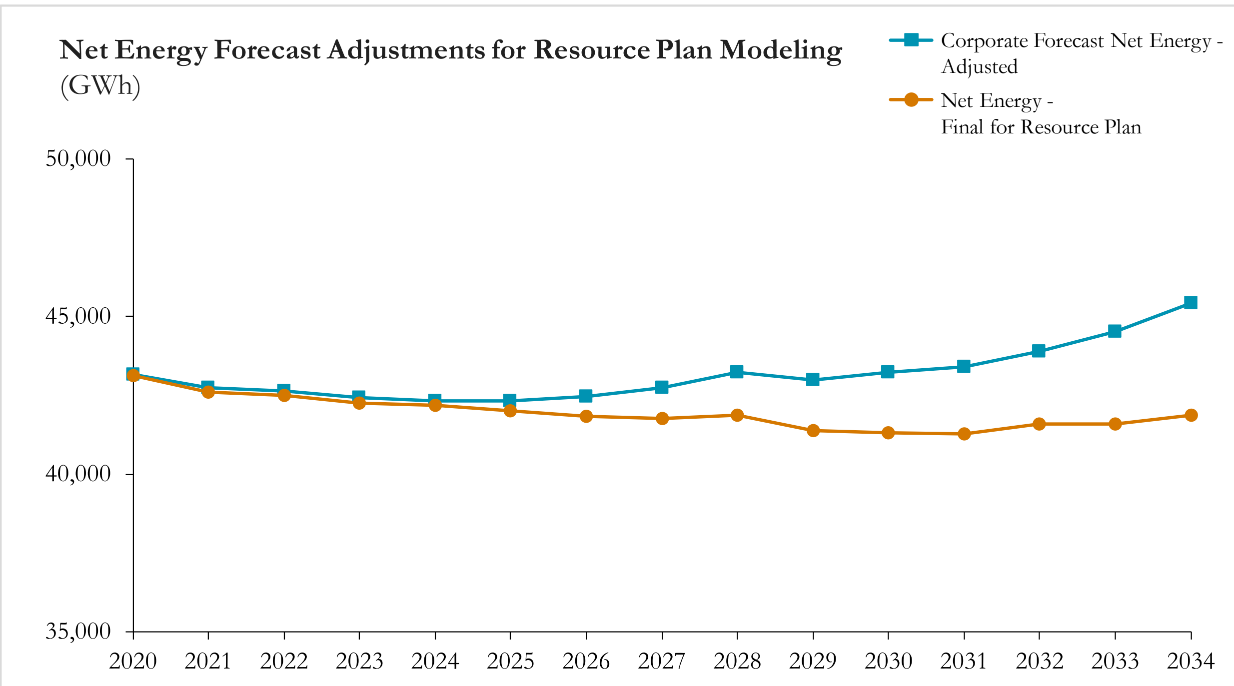
The updated corporate peak demand forecast shows relatively slow load growth, with an average annual growth rate of 0.7 percent over the planning period, after accounting for reductions to demand from the future energy efficiency (EE) achievements embedded in the forecast. Our corporate energy demand forecast also indicates that we expect net energy requirements to be somewhat lower than those forecasted in our initial filing. The fall 2019 forecasts indicate relatively flat growth of approximately 0.2 percent over the full 2020-2034 planning period. In general, we expect both load and energy demand to be slightly lower than the forecast used in our initial filing through most of the planning period – due to factors such as weather-driven near-term energy demand declines, additional anticipated EE savings, and adjustments to anticipated commercial and industrial load.[9] However, our corporate forecast now reflects an expectation that electric vehicle growth will increase, especially in the later years of the analysis period.

We used these corporate forecasts as the basis for our Strategist and EnCompass modeling but made some further adjustments, in order to account for modeling load-modifying resources – such as EE, demand response (DR), and distributed generation – as competing with supply-side resources in our modeling process. Prior to our 2020-2034 Resource Plan, we netted out these resources at an assumed fixed level of adoption across the planning period, and our corporate forecasting process continues to use this method to estimate our net energy and load into the future. However, in our initial plan we filed in July 2019, for the first time we tested the economic impact of including various "bundles" of EE and DR – in other words, portfolios of EE or DR measures at an assumed average cost – in our resource planning process in order to allow these resources to compete with traditional supply-side resources, such as large-scale renewables or gas resources.

[9] We note that the corporate forecasts underlying our Supplement modeling do not reflect potential effects of the COVID-19 pandemic and resulting recession on our energy demand. It is too early to know to what extent energy demand will decline in response or the duration of these effects.

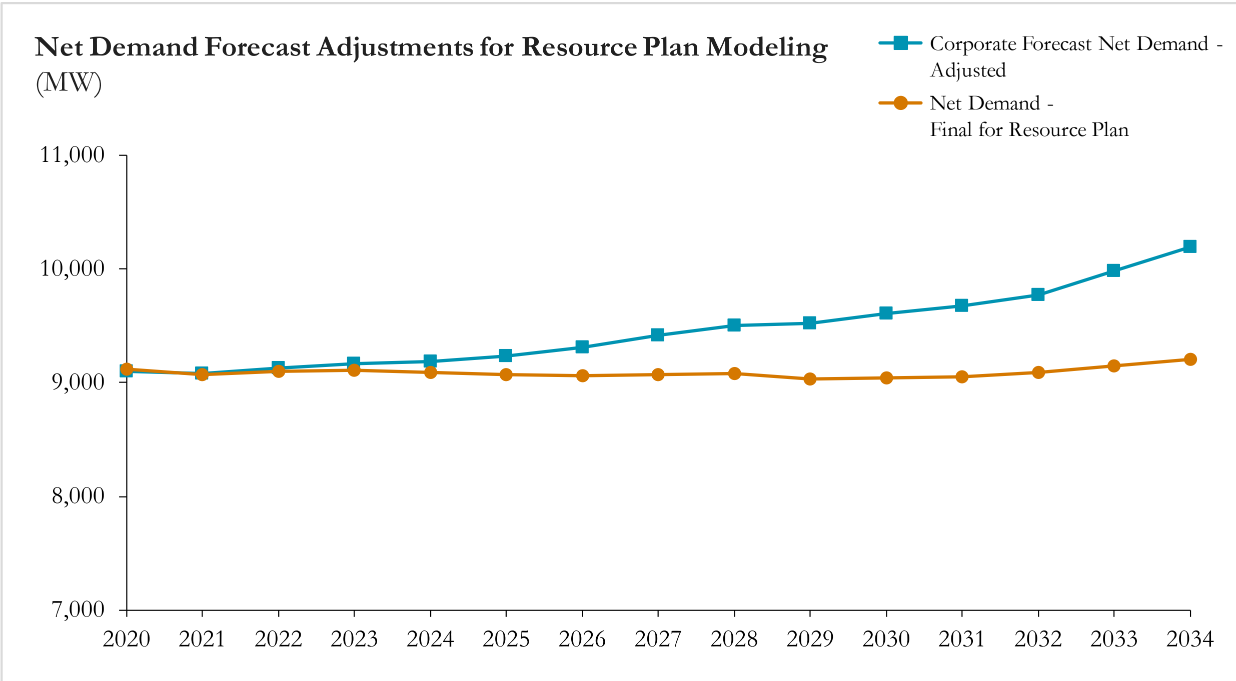
In order to avoid double counting, this process requires us to adjust our corporate forecast for use in Strategist and EnCompass modeling, removing the levels of EE embedded in the corporate forecast so we can instead model the effects of avoided energy demand and load from the first two EE bundles.[10] The end result is a net demand and energy forecast for use in the Resource Plan. We note that because the EE bundles avoid more energy and load than the amount of EE assumed in the corporate forecasts, the resulting load and energy demand forecasts that we use in resource plan modeling diverge from the corporate forecasts. We show the effect of these adjustments on these forecasts in Figures 2-3 and 2-4 below.

Figure 2-3: Net Energy Requirements Forecast Adjustments for Resource Plan Modeling



[10] In our initial filing we showed that these two EE Bundles were economic relative to a scenario in which no incremental EE measures were pursued, thus for the purposes of this Supplement, we have included them in our baseline modeling.

Figure 2-4: Net Peak Demand Forecast Adjustments for Resource Plan Modeling



b. MISO Reserve Margin and Capacity Accreditation

After determining a baseline of customer load and energy demand, we then assess the ability of our existing resources to meet customer needs. MISO prescribes Resource Adequacy (RA) requirements in order to ensure we maintain a level of resources that exceeds our level of demand by a specific margin, to cover potential future uncertainty in the availability of resources or level of demand.[11] It publishes these requirements in an annual Loss of Load Expectation (LOLE) study. At a high level, we determine the Northern States Power (NSP)-specific reserve margin based on the MISO-wide reserve margin and the coincident peak demand factor of our own peak load in relation to the MISO peak.

While our peak coincident factor has remained consistent at 95 percent, MISO increased its required planning reserve margin to 8.9 percent in its most recent LOLE study (up from 8.4 percent in the previous study). Therefore, our effective reserve margin used in Supplement modeling increased as well, from the 2.98 percent used in our initial filing to 3.46 percent for this Supplement.

[11] 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.

Figure 2-5: MISO Planning Reserve Margin Calculation – NSP System Planning Year June 1, 2020 to May 31, 2021

$$(95\ percent\ coincidence\ factor)x\ (1 + 8.9\ percent) - 1 = 3.46\ percent\ effective\ reserve\ margin\ for\ NSP$$

After we determine this MISO-prescribed obligation, we consider the types of resources suitable to meet the requirements. Resource accreditation represents a measure of a resource's reliable contribution to system resource adequacy (RA) needs. A resource's operation, maintenance, and utilization directly impact the portion of a unit's nameplate capacity rating that can be accredited as counting toward our reserve requirements. A resource's expected contribution to system RA is measured by "unforced capacity" (UCAP) values instead of installed capacity (ICAP). UCAP is calculated differently for dispatchable resources, EE, and DR as compared to variable renewable resources.[12]

The RA values for most types of resources have not changed between our initial filing and this Supplement. However, for variable resources – especially wind – MISO modifies its assigned RA values from time to time. In its latest report, which was issued after our initial filing, MISO assigned wind an ELCC of 16.7 percent for wind in Zone 1,[13] which is higher than the 15.6 percent we used in our initial filing.[14] This means that for every 100 MW of installed wind capacity, we can count 16.7 MW toward our RA requirements. MISO has not issued guidance regarding forward-looking wind ELCC values, so we use 16.7 percent across the planning period. As discussed above, we have also updated our approach to accounting for solar RA values. Consistent with MISO's latest Transmission Expansion Plan analysis, we use uses solar capacity accreditation values that start at the current 50 percent level in 2020-2023 and decline to 30 percent by 2033.

c. Resource Baseline

After evaluating customer needs and MISO RA requirements, we then evaluate the baseline of resources we currently have to serve customers. Our baseline includes all owned, contracted, or otherwise available resources on the system or resources that

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[12] Includes wind and solar.
[13] *See Planning Year 2020-2021 Wind & Solar Capacity Credit*. MISO (December 2019), at 4. Available at: https://cdn.misoenergy.org/2020%20Wind%20&%20Solar%20Capacity%20Credit%20Report408144.pdf
[14] We note that we have shifted from using the MISO footprint average wind ELCC of 15.6 percent to the most recent Zone 1 specific ELCC of 16.7 percent, in order to better capture the higher locational value of wind resources in our specific region

have received regulatory approval as of January 31, 2020 (our resource lock-in date for modeling purposes) through their established expiration dates.[15] We note that this is a departure from our approach in our initial filing, where resources we had proposed and were pending approval were also included. This approach results in a baseline capacity of over 15,000 MW,[16] approximated below by resource type:

Table 2-1: Existing and Approved NSP System Resources as of the Resource Lock-in Date (Approximate)

Resource Type	MW (Max Cap)
Wind	4,200 (including capacity currently under development)
Solar	1,000
Other renewables (biomass, landfill gas, hydroelectric)	950
Nuclear	1,740
Natural gas or Oil[17]	4,740
Coal	2,400

As discussed above, specific baseline resources included in our Supplement modeling have not substantially changed since our initial filing, with a few notable exceptions:

- The Mankato Energy Center is modeled using the existing PPA expiration dates in this filing, consistent with the Commission's order denying our request to acquire the plant as a regulated asset;
- The Crowned Ridge Wind facility was reduced from 600 MW overall to 400 MW, as a result of the seller encountering prohibitively high transmission interconnection upgrade costs for the final phase;
- We eliminated some resources where contracts had expired, and any new contracts had not yet been completed or granted regulatory approval by the January 31 resource lock-in date;
- Consistent with Commission feedback, we have aligned existing unit retirement dates with their current financial end of lives. Sherco Unit 3, for example, now is assumed to have a reference retirement date of 2034 rather than 2040; and

[15] This could include contract expiration, planned retirement or financial end of life. Black start resources are one exception to this general rule.
[16] On a maximum capacity basis. Maximum capacity is approximately the same as ICAP but includes some adjustments for unit availability.
[17] Does not include the Sherco CC, which is expected to come online by 2027.

- We also have included black start placeholder capacity in our modeling. Black start critical units in Minnesota and Wisconsin are scheduled to retire within the planning period, but in reality, we cannot operate a reliable system without viable black start units. While we continue to develop a robust black start alternatives analysis, we included interim placeholder capacity (and associated costs) in our modeling from the units' current retirement dates out to 2030. We emphasize that this placeholder capacity is for modeling purposes only.

d. System Net Surplus/Deficit

After determining customer needs, resource adequacy requirements, and our resource baseline, we can calculate the net resource surplus or need in a given year on our system, across the planning period. Where we encounter a net deficit, we need to add resources to our system to meet customer needs.

As shown below, accounting for existing and approved resources only, and taking into consideration current unit retirement dates, we anticipate a net capacity surplus to our MISO RA requirements through 2025, and a deficit thereafter. Our Reference Case and various baseload scenario capacity expansion plan modeling presented in the next section assess potential combinations of resources that address this capacity deficit.

Table 2-2: 2020-2034 System Net Accredited Capacity Surplus/Deficit Prior to Expansion Planning (MW, resource values measured in terms of UCAP)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
System needs															
Forecasted gross load (before forecasted EV load)	10,502	10,563	10,635	10,711	10,780	10,842	10,911	10,982	11,053	11,119	11,184	11,253	11,324	11,391	11,452
Forecasted EV load	8	12	17	25	35	44	53	65	79	99	126	163	214	273	336
Forecasted EE[18] (reduction to load)	(1,395)	(1,508)	(1,550)	(1,625)	(1,723)	(1,817)	(1,907)	(1,975)	(2,052)	(2,189)	(2,269)	(2,367)	(2,448)	(2,521)	(2,583)
Forecasted net load	9,115	9,067	9,101	9,111	9,092	9,068	9,057	9,072	9,080	9,029	9,041	9,049	9,090	9,143	9,205
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Load	8,659	8,614	8,646	8,655	8,638	8,615	8,604	8,618	8,626	8,578	8,589	8,597	8,636	8,686	8,745
MISO PRM	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%
NSP Obligation	9,430	9,380	9,416	9,426	9,406	9,382	9,370	9,385	9,393	9,341	9,354	9,362	9,404	9,459	9,523
Existing and approved resources (UCAP)															
Load Management *(existing)*	1,012	1,027	1,041	1,055	1,066	1,072	1,077	1,078	1,077	1,071	1,059	1,048	1,037	1,026	1,016
Load Management *(potential study)*	33	165	232	294	341	382	394	407	423	440	458	478	499	521	545
Coal	2,295	2,295	2,295	2,295	1,647	1,647	1,647	994	994	994	994	994	994	994	994
Nuclear	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,019	1,019	1,019	498	0
Natural Gas/Oil	3,858	3,858	3,858	3,858	3,713	3,403	3,112	2,831	2,831	2,831	2,831	2,288	2,012	2,012	2,012
Sherco CC	0	0	0	0	0	0	0	728	728	728	728	728	728	728	728
Biomass/RDF	110	110	110	86	86	61	61	61	29	29	29	19	19	19	19
Hydro	881	1,001	993	993	993	162	162	162	162	162	162	162	156	152	152
Wind	498	623	672	647	635	631	626	611	605	583	582	566	563	498	479
Grid-scale solar	129	129	128	127	122	116	110	105	99	94	88	83	78	73	72
Solar*Rewards Community Solar	329	357	394	421	409	392	376	359	343	326	309	292	276	259	259
Distributed Solar	37	45	53	60	64	68	71	74	76	78	78	79	78	77	81
Existing Resources	10,824	11,252	11,418	11,478	10,717	9,576	9,278	9,052	9,007	8,976	8,338	7,757	7,459	6,857	6,358
Net Resource (Need)/Surplus	1,394	1,871	2,002	2,052	1,311	195	(92)	(334)	(386)	(365)	(1,016)	(1,605)	(1,945)	(2,602)	(3,166)

C. Modeling Results and Preferred Plan Selection

After establishing our need and existing resource treatment in the pre-modeling refresh, we then transitioned into modeling our expansion plans, which consisted of four distinct phases: 1) Baseload Scenario Modeling; 2) Baseload Scenario Sensitivity Testing; 3) Evaluation and Preferred Plan Selection; and 4) Preferred Plan Sensitivity Testing. We discuss each phase below.

1. *Baseload Scenario Modeling*

The first step in the modeling process included baseload scenario capacity expansion modeling in both Strategist and EnCompass. In each model, we used the same fifteen

[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.

baseload scenarios – examining different combinations of baseload retirement dates – that we analyzed in our initial Resource Plan. Re-modeling all scenarios in Strategist allowed us to identify how changed inputs and foundational assumptions may have changed portfolio outcomes, relative to our July 2019 Preferred Plan. We then were able to compare outputs from our EnCompass analysis to these refreshed Strategist results, as we prepare to fully transition to this new modeling tool going forward. Below we include a brief overview of each model and then discuss the outcomes of our baseload scenario modeling.

a. Strategist and EnCompass Overview

The Strategist model conducts capacity expansion by using dynamic programming, with some simplifications. At a high level, dynamic programming is a method that calculates the cost of every possible plan, and then sorts them by cost to determine the optimal plan. In order to reduce computational intensity of calculating every possible outcome, Strategist employs refinements to eliminate duplicative calculations and employs a total cap on the number of plans at a pre-defined level. This allows the model to discard the plans that are higher cost than the cutoff point as the optimization progresses (a "truncation" process, as we discussed in our July 2019 filing).

Additionally, Strategist employs many simplifications in the unit commitment and dispatch process used to evaluate portfolio costs. For example, the model dispatches a given generation portfolio against a simplified load duration curve – which only captures load from one representative week in each month, or 2,016 hours per year. Strategist then sorts the representative load hours from high to low, and subsequently matches each load requirement against a resource supply stack sorted by cost to determine which units should run to meet the given load level. As a result, Strategist does not incorporate many of the important benefits an hourly chronological model can provide. It does not use an actual unit commitment process that includes such factors as startup costs and run time constraints. Strategist also does not enforce hourly ramp rates due to the absence of chronological dispatch, and only determines economic market interactions and storage resource dispatch "after the fact" in a post-dispatch process.

In contrast, EnCompass is a full chronological hourly model that uses a mixed integer optimization engine to simultaneously optimize capacity expansion, unit commitment and dispatch (including storage), economic market interaction, and ancillary service requirements. EnCompass does not attempt to enumerate every possible plan but converges to an optimal solution considering all factors at once. Although

EnCompass performs the production cost function simultaneously with the capacity expansion process, some simplifications in the commitment and dispatch assumptions are required for computational and time limitations.

The Company, based on consultation with the software vendor, performed the capacity expansion runs using a representative on-peak and a representative off-peak day for each calendar month of the year. Additionally, we used a simplified commitment process that incorporated many aspects of the startup cost and run time restrictions, but relaxed enforcement of certain assumptions that are not critical for a long-term "expected value" type of analysis. EnCompass allows four different options for unit commitment, which allows us to simplify the simulation to mitigate runtime or size (memory) concerns. "Full Commitment" is the standard setting that forces the number of units online, startups and shutdowns to be integer – or whole number – values; "Partial Commitment" allows these values to be continuous values which allows fractions of a unit to be started and online; "No Commitment" ignores the minimum capacity constraint for resources; and "No Dispatch" is an input only processing option that yields no simulation or results. For our capacity expansion modeling, we utilized the Partial Commitment approach because – due to the complexity of the Full Commitment approach and processing capabilities – the model would not be able to solve a capacity expansion run for a 25-year optimization period.

To ensure that the simplified commitment approach provided appropriate cost estimates, we then ran every expansion plan through a full chronological 8,760 hour-per-year production costing simulation for the years 2020 through 2045, consistent with the years used for cost estimates in our initial filing. For these production costing runs, we used the Full Commitment option to ensure all operating parameters for the resources were enforced. We use the results of these full production costing runs for all the net present value (PVRR and PVSC) estimates we present from EnCompass modeling in this filing. More discussion on EnCompass and mixed integer modeling can be found in Attachment F, which is provided by the EnCompass vendor, Anchor Power Solutions.

b. Baseload Scenario Modeling Results

As noted above, we conducted capacity expansion modeling on the same fifteen baseload scenarios as in the initial filing, with the exception of adjustments to Sherco 3's default retirement date. These scenarios can be grouped into "families" that test different permutations of retirement dates of our coal and nuclear units; some that accelerate retirement and some that extend the lives of our nuclear units. We do not examine any scenarios that extend the lives of our coal units. A summary of scenarios and retirement dates is included below.

Base

- Scenario 1 **(Reference)** – All units retire at their current dates (King in 2038, Sherco 3 in 2034, Monticello in 2030 and Prairie Island 1 and 2 in 2033 and 2034 respectively)

Early Coal Family[19]

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

Early Nuclear Family

- 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.

Nuclear Extension Family

- 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.

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[19] We note that for purposes of this Supplement, early Sherco 3 retirement scenarios set this unit to stop generating by the end of 2029 rather than in 2030 as it did in our initial modeling presented in July 2019. We believe this approach more closely conforms to our commitment to retire coal by 2030.

- 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.

As discussed above, Strategist and EnCompass – while similar in their objectives – have distinctly different modeling processes and thus the capacity expansion and net present value estimates vary by model. Despite the divergences in capacity expansion and dispatch methodology, however, both models provided directionally consistent baseload scenario cost results. As demonstrated in the results below, both models' results show that the early coal retirement and nuclear extension scenarios generally provided the greatest benefit to customers.

Figures 2-6 and 2-7 show the cumulative 2020-2034 capacity additions for each of the fifteen baseload scenarios in each of the respective models, and these results illustrate some key differences in the way each model solved for capacity expansion plans. Figure 2-6 shows that Strategist – which uses a load duration curve approach – selected large quantities of solar additions along with much smaller quantities of wind and firm peaking resources. Figure 2-7 shows that EnCompass model selected a portfolio that includes a greater balance between solar, wind and firm peaking additions. Because EnCompass utilizes hourly, chronological dispatch – even given simplifications employed for capacity expansion modeling such as average days per month and partial unit commitment – the model recognizes a system need for flexible and dispatchable resources.

In this way, EnCompass better reflects grid operations and values a more complete range of resource attributes than Strategist modeling. Whereas an hourly chronological model will assign value to capacity, energy and flexibility according to the grid's needs across each hour in an average day – or a full year – a model that utilizes load duration curves for capacity expansion simulations primarily values capacity adequacy at an annual peak and a more "averaged" value for energy. As a result, EnCompass expansion plans include a more diverse set of resources, balancing solar additions with more wind and firm peaking generation additions than the Strategist expansion plans.

Figure 2-6: Strategist 2020-2034 Capacity Expansion Plans by Baseload Scenario

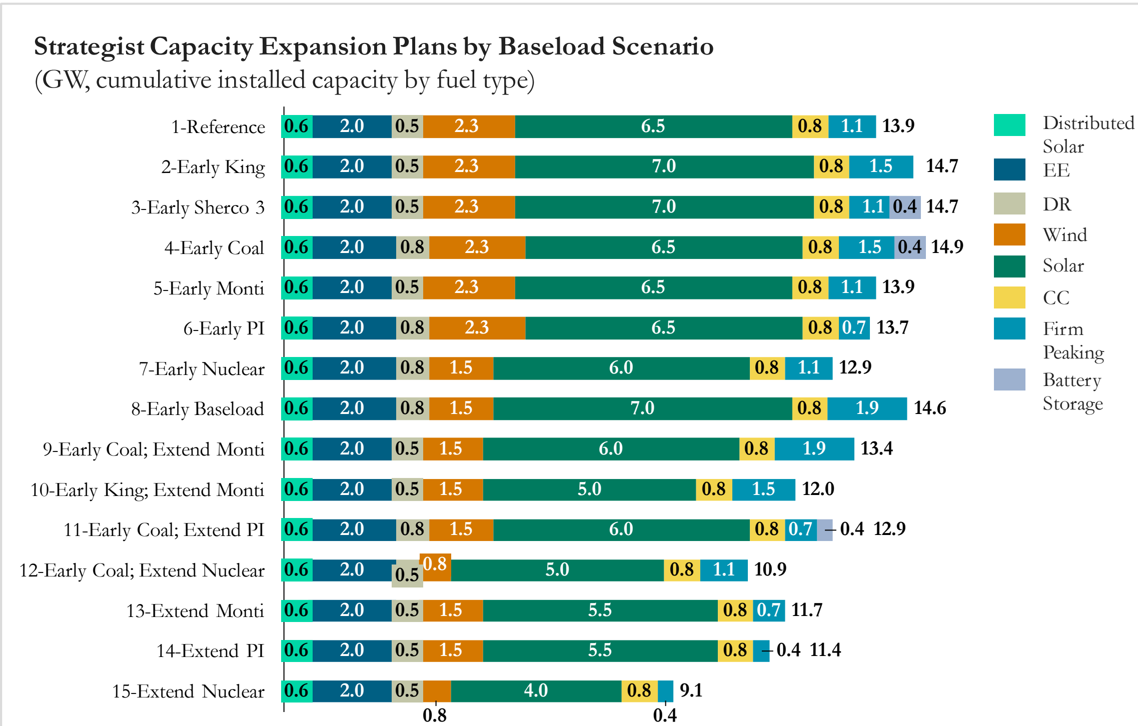
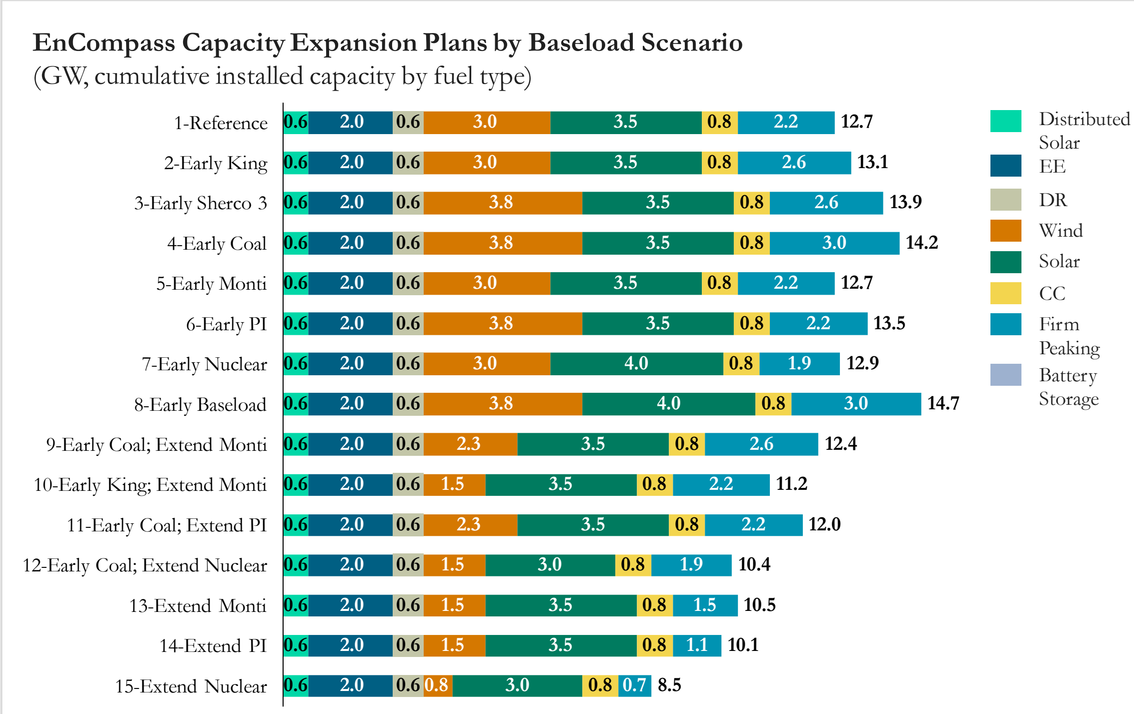
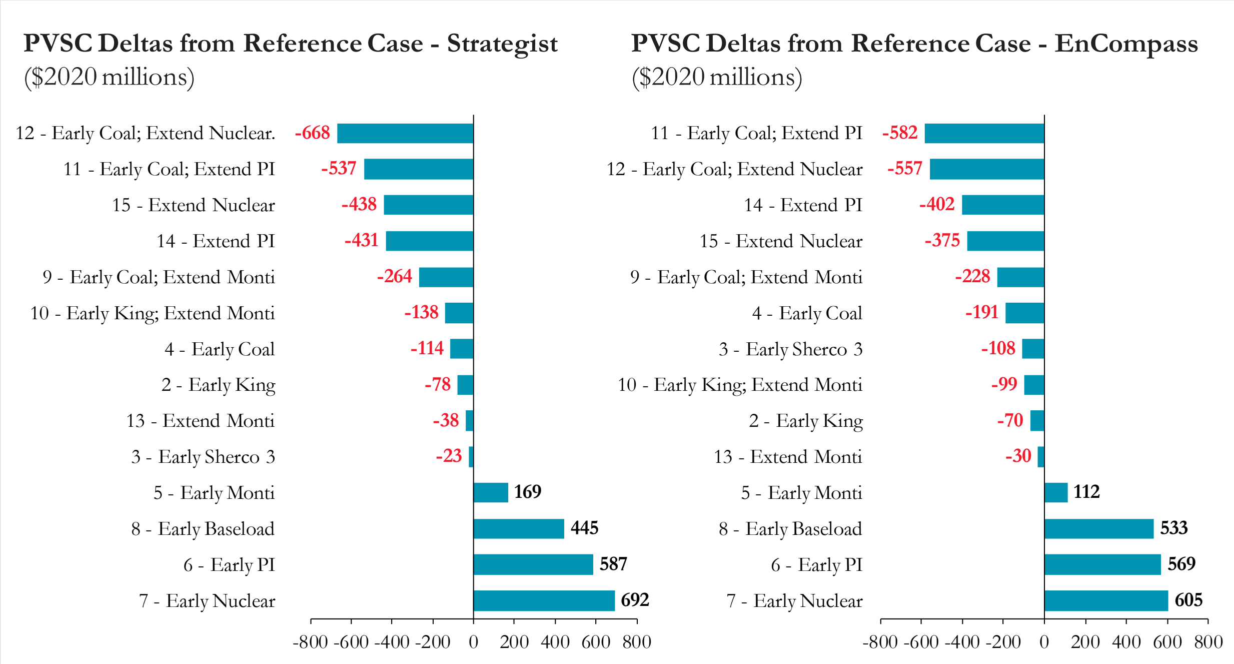


Figure 2-7: EnCompass 2020-2034 Capacity Expansion Plans by Baseload Scenario



These capacity expansion plans yielded the following net present value of savings/cost results. We use PVSC and PVRR deltas as primary indicators of these scenarios' economic favorability—the latter considering just the net present value of revenue requirements, while the former factors in additional costs of environmental externalities and regulatory cost of carbon—because they represent our best understanding of the long-term savings or costs our customers would incur, relative to the Reference Case's "business as usual" approach. Similar to our initial filing, the scenarios that include nuclear extensions and early coal retirements generally result in the lowest cost plans, on a PVSC basis, and scenarios that retire nuclear units early are the highest cost. This pattern holds true across both models, despite somewhat divergent capacity expansion results.

Figure 2-8: Baseload Scenario PVSC Deltas, Relative to the Reference Case

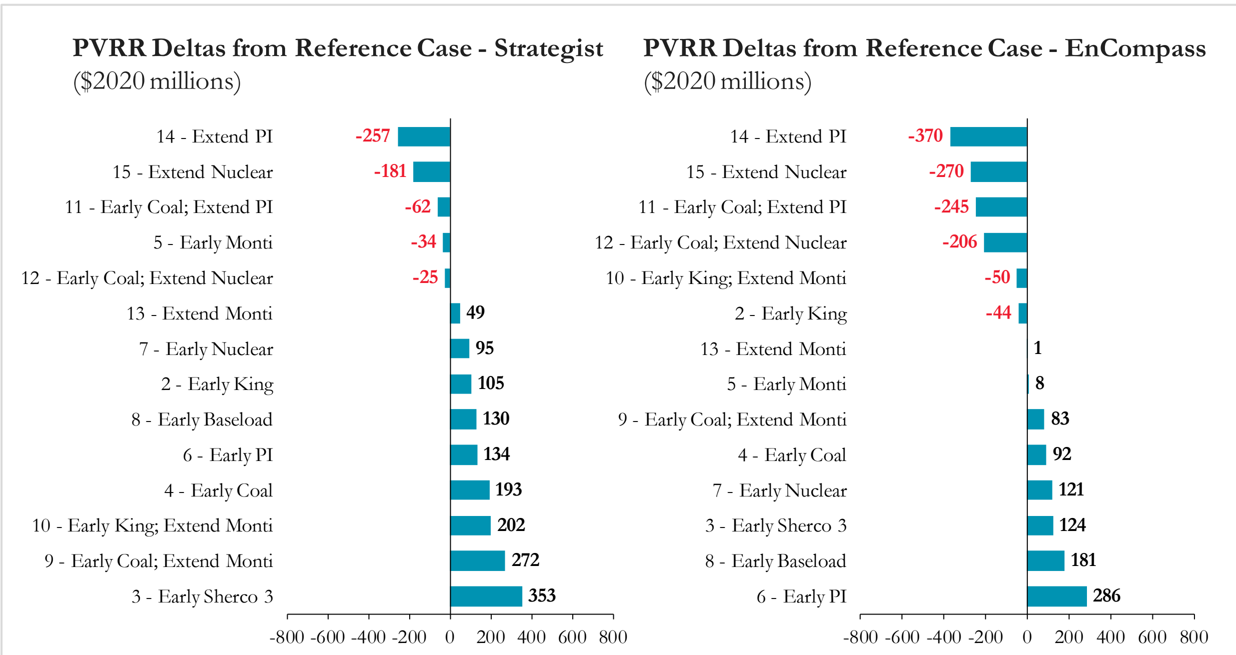


While the PVSC cost and savings deltas for each scenario and the ordering of the scenarios is not identical across the Strategist and EnCompass results, we note that the scenarios including nuclear extension and early coal retirement consistently yield the most favorable outcomes. Scenario 9 – which formed the basis of our initial Preferred Plan and again represents our preferred scenario in this Supplement – continues to offer one of the most attractive PVSC savings results. Additionally, several scenarios that include Prairie Island nuclear extension scenarios return higher levels of savings, consistent with results in our initial filing.

We note, however, that the savings deltas for Scenario 9 and other nuclear extension and early coal retirement scenarios have generally decreased from the values that we presented in our July 2019 filing. This change is primarily a function of modeling assumption updates. In particular, lower forecasted wind resource costs – as well as lower natural gas and energy market prices – now make replacement carbon-free capacity for retiring nuclear units less expensive and thus, these changes have eroded some of the savings associated with nuclear extension. Further, updating Sherco 3 retirement dates in the Reference Case – from 2040 to 2034, as ordered by the Commission – eroded some of the PVSC savings associated with the Sherco 3 early retirement. Because the Reference Case now incorporates the carbon benefits of moving the Sherco 3 retirement date from 2040 to 2034, the early coal retirement scenarios only capture the additional benefits associated with moving the Sherco 3 retirement date from 2034 to 2030, rather than from 2040 to 2030 as reflected in our initial filing.

PVRR results in the latest round of modeling have changed more noticeably than the PVSC results. Here again, updated assumptions are primary drivers of the changes relative to our initial Plan, including wind and fuel price developments. Without accounting for externalities and regulatory cost of carbon, both models show lower benefits associated with nuclear extension and early coal retirement scenarios.

Figure 2-9: Baseload Scenario PVRR Deltas from the Reference Case



In general, the PVRR deltas in these Strategist modeling results are less favorable for most scenarios, when compared to the Reference Case. Many factors in the updated assumptions influence the results but, as with the PVSC results, the largest contributors are the lower forecasted wind prices and the removal of the 80 percent carbon reduction constraint in the modeling. In the modeling presented in our July 2019 filing, all scenarios were required to meet the 80-by-30 carbon reduction goal, including the Reference Case. Therefore, that 2019 Reference Case included a significant amount of higher cost wind additions to meet the carbon threshold, and several other scenarios with less carbon intensive baseload units remaining had to add fewer such resources to meet the carbon goal. In this analysis, wind resource costs are projected to be lower, and the Reference Case is allowed to optimize without restrictions. This leads to smaller overall differences in the mix of renewable additions between the Reference Case and other baseload scenarios, and thus different PVRR results.

2. *Baseload Sensitivity Testing*

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 how resilient a given 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. A comprehensive accounting of individual sensitivities results is available in Attachment A, Section X: Modeling Scenario Sensitivity Analysis PVRR & PVSC.

We also examined combination sensitivities – as in our initial filing – similar to the approach MISO uses in its MTEP Futures Scenario modeling. Many of the input assumption variables in our modeling are correlated – in other words, low load often does not occur in isolation, rather it may be combined with changes in fuel or technology costs – which means examining combinations of variable changes may present a more realistic view of the future. We discuss the assumptions and results of these combination "Futures" in more detail below.

a. Futures Sensitivities Assumptions

We developed two Futures Scenarios using the 2018 MTEP Futures as guideposts. As in our July 2019 filing, we conduct one scenario that reflects a High Electrification future and one that reflects High Distributed Solar adoption. These scenarios, combined with our base PVRR and PVSC results, vary on four assumptions to which the model is highly sensitive: 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 are enumerated in Table 2-3 below:

Table 2-3: Futures Scenarios Parameters

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 Future, we examine a case in which higher load levels are expected to stimulate higher fuel demand and consequently higher overall fuel prices. At the same time, we assume new technology costs are lower than our baseline assumptions.[20] Conversely, for the High Distributed Solar Future, 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 assume low new resource costs in this scenario.

As we stated in our initial filing, it is important to note that these Futures Scenarios are intended to examine the resiliency of each baseload scenario under a combination of assumptions changes that we believe are plausible future states. They are not intended to show us 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 we have no control over variables such as fuel prices and new resource capital costs.

[20] Note: to construct this Scenario, we used a high electrification forecast provided by E3, informed by their Minnesota PATHWAYS study provided as Appendix P3 to our July 2019 filing.

Figure 2-10: Futures Sensitivities Fuel Price Assumptions

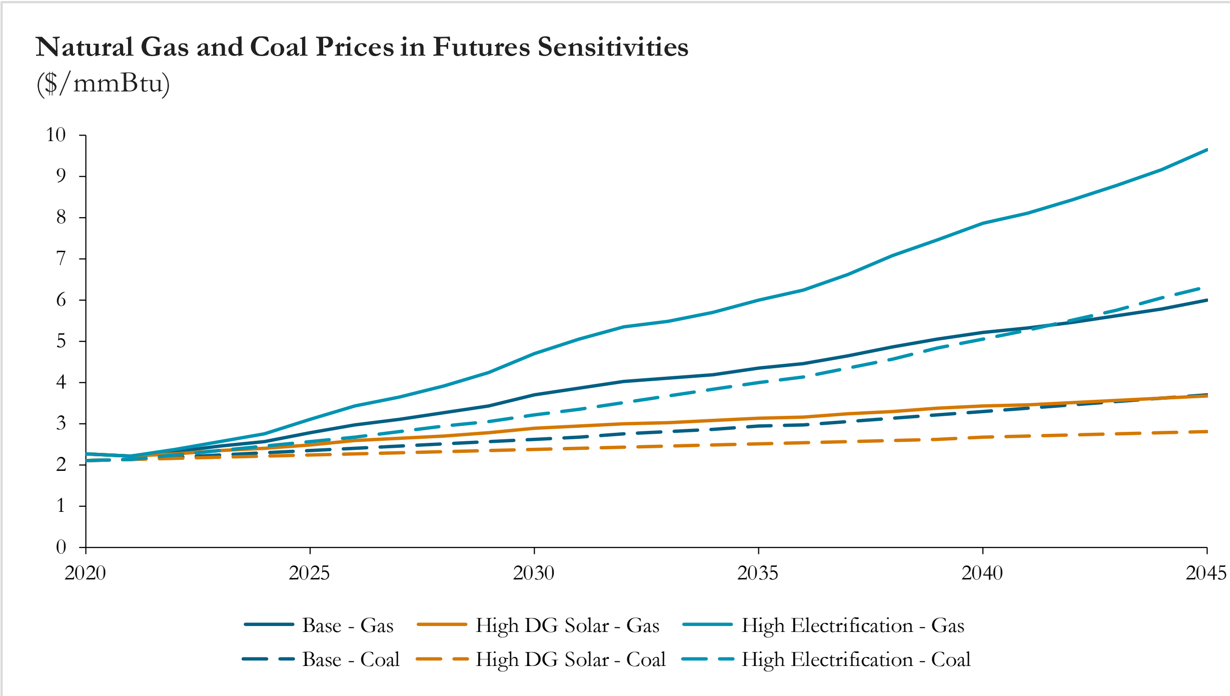


Figure 2-11: Futures Sensitivities NSP System Peak Load

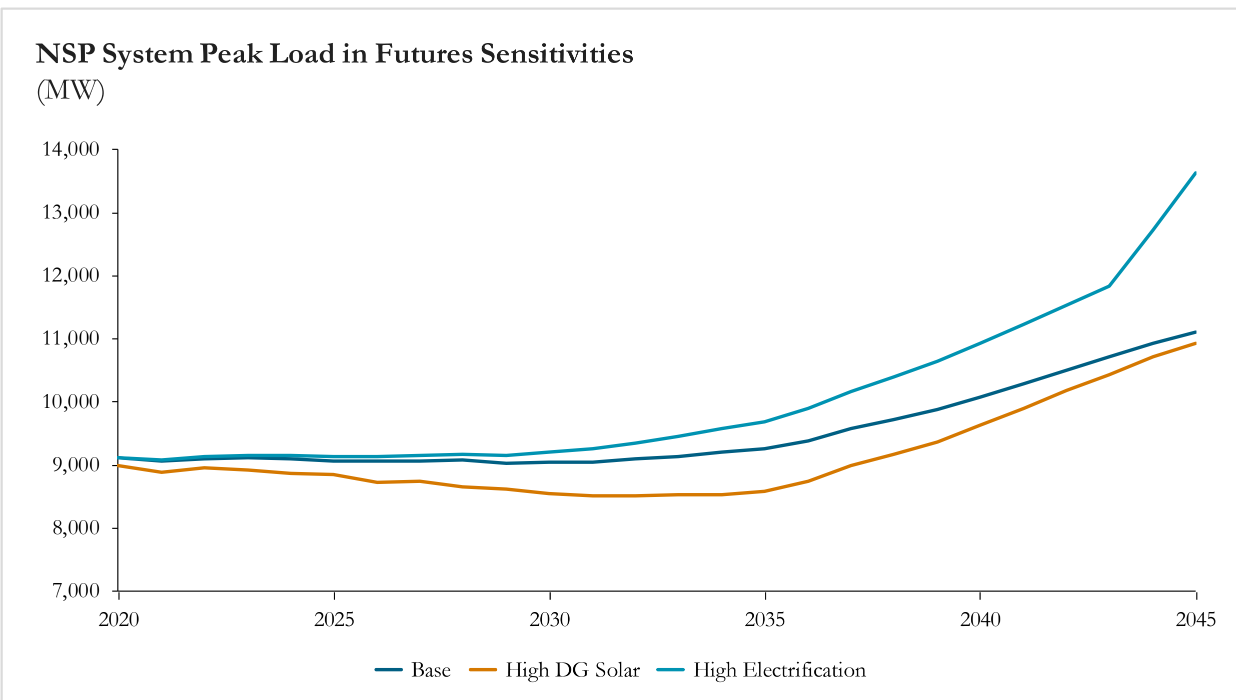


Figure 2-12: Futures Sensitivities NSP System Energy Demand

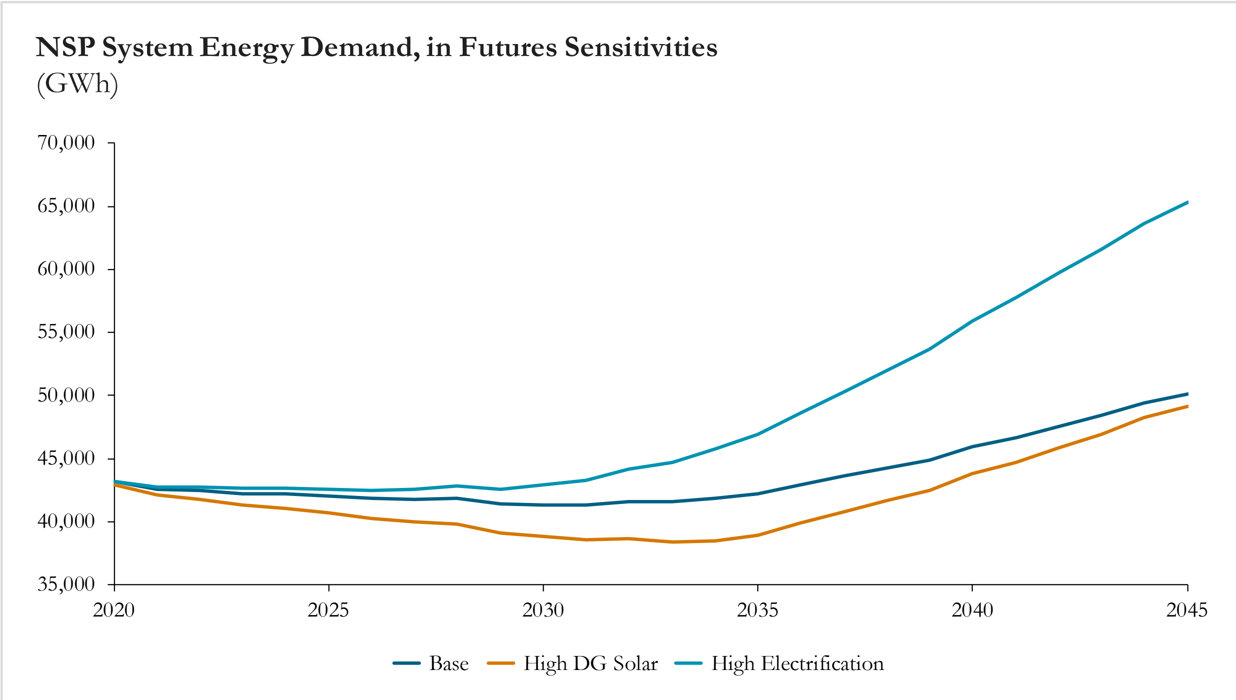
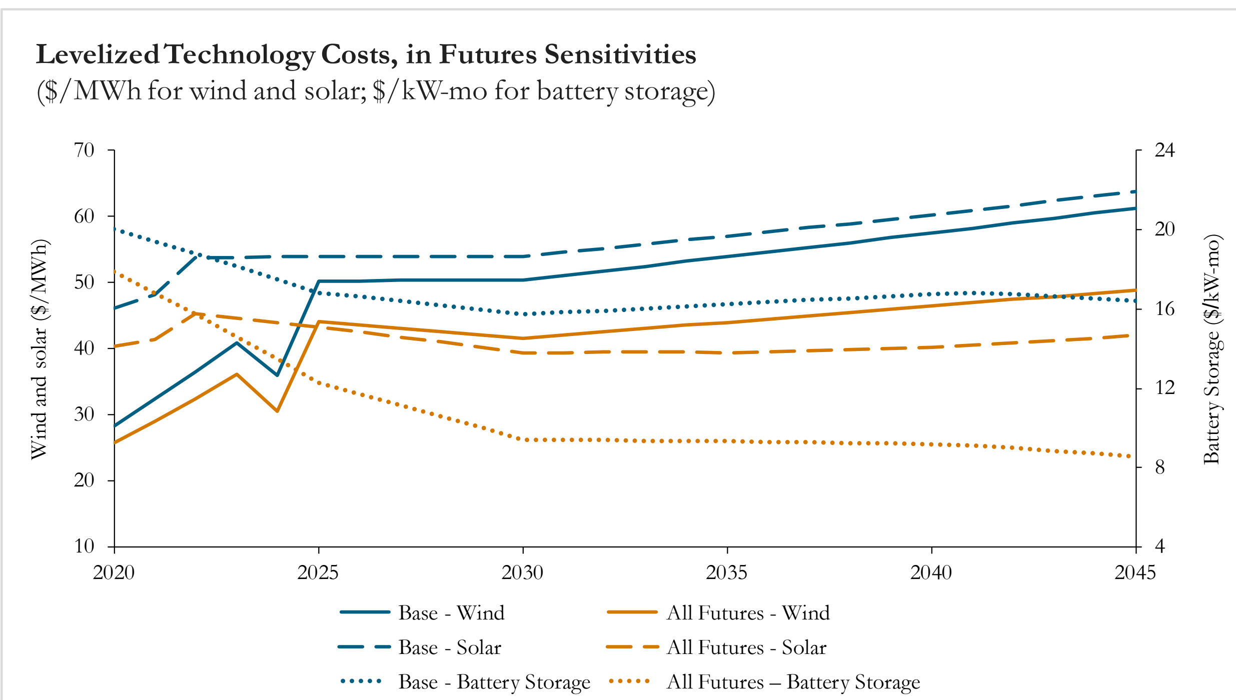


Figure 2-13: Futures Sensitivities Technology Cost Assumptions

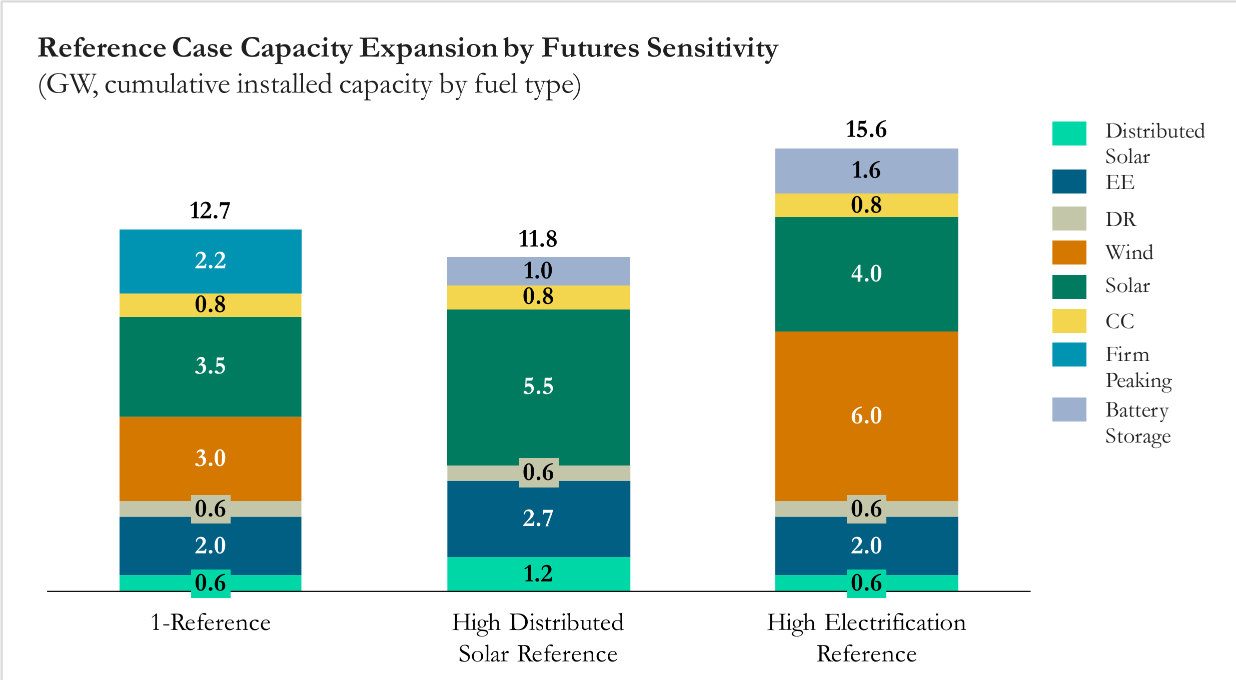


b. Futures Sensitivities Results

Assessing the cumulative expansion plans across baseload scenarios under these different Futures shows us that the level and type of capacity selected varies widely across the Futures. The use of low technology cost assumptions in both the High Electrification and High Distributed Solar Futures leads to substantially more battery storage selected in all plans, as compared with the Base scenario analyses. The base assumptions assume relatively higher battery costs, and thus the model chooses more firm peaking capacity (which is modeled as CTs) in those scenarios. With respect to renewable capacity selection, two key assumptions drive divergent outcomes across the Futures. Lower renewable cost assumptions generally would cause the modeling to select more wind and solar; however, load levels are a key differentiator between the High Distributed Solar and High Electrification Futures. In the High Electrification Future, the model generally selects significant levels of wind and solar, in addition to the battery storage-CT tradeoff discussed above. In the High Distributed Solar future – because load is lower overall – the model selects less capacity overall, and additions are primarily solar, alongside battery storage, with no wind or CTs.[21] We show results from the Reference Case expansion plan, across each Futures Scenario result, as an example of these trends in Figure 2-14 below.

[21] We note that these futures outcomes – where vast amounts of variable renewable generation and use-limited resources are selected – lead to questions regarding the ability of these portfolios to meet customers' reliability needs across every hour of every day. We discuss further analysis around these Futures in the context of our selected Supplement Preferred Plan below in subpart 4.c and in Attachment A, Section XI: Supplement Preferred Plan Sensitivities – Reliability Analyses.

Figure 2-14: Reference Case Results by Futures Sensitivity



Net present value deltas of all our Futures analyses' capacity expansion plans are shown in Table 2-4 below. These results show us that, in general, scenarios that include early coal retirement and nuclear extension perform well relative to other scenarios across the Futures. They also generally provide overall customer savings relative to the Reference Case in their respective Futures analysis, and particularly in the High Electrification Futures. In most cases, scenarios that retire nuclear units early perform the worst across Futures.

Table 2-4: Futures Sensitivities Results Deltas by Baseload Scenario[22]

Baseload Scenario *(all values $2020 millions)*	**Base PVSC**	**Base PVRR**	**High Distributed Solar Future PVSC**	**High Electrification Future PVSC**
1 - Reference	--	--	--	--
2 - Early King	($70)	($44)	($94)	($64)
3 - Early Sherco 3	($108)	$124	($151)	($185)
4 - Early Coal	($191)	$92	($311)	($391)
5 - Early Monti	$112	$8	$141	$146
6 - Early PI	$569	$286	($341)	$414
7 - Early Nuclear	$605	$121	($239)	$533
8 - Early Baseload	$533	$181	$9	$259
9 - Early Coal; Extend Monti	($228)	$83	($218)	($467)
10 - Early King; Extend Monti	($99)	($50)	($59)	($262)
11 - Early Coal; Extend PI	($582)	($245)	($1,037)	($1,851)
12 - Early Coal; Extend All Nuclear	($557)	($206)	($658)	($1,833)
13 - Extend Monti	($30)	$1	$69	($54)
14 - Extend PI	($402)	($370)	($777)	($1,668)
15 - Extend All Nuclear	($375)	($270)	($387)	($1,454)

3. *Evaluation and Preferred Plan Selection*

After completing our final baseload scenario production costing runs and examining baseload sensitivity results, we evaluated how each baseload scenario performs across multiple criteria that reflect our planning objectives. Based on the relative merits of these plans across the metrics – shown in the table and discussed further below – we believe Scenario 9 continues to be the most appropriate selection for our Preferred

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[22] Note that the deltas shown are relative to the Reference Case in each sensitivity.

Plan, achieving our carbon reduction goals and resulting in savings on a societal cost basis, while maintaining reliability and limiting customer risk.

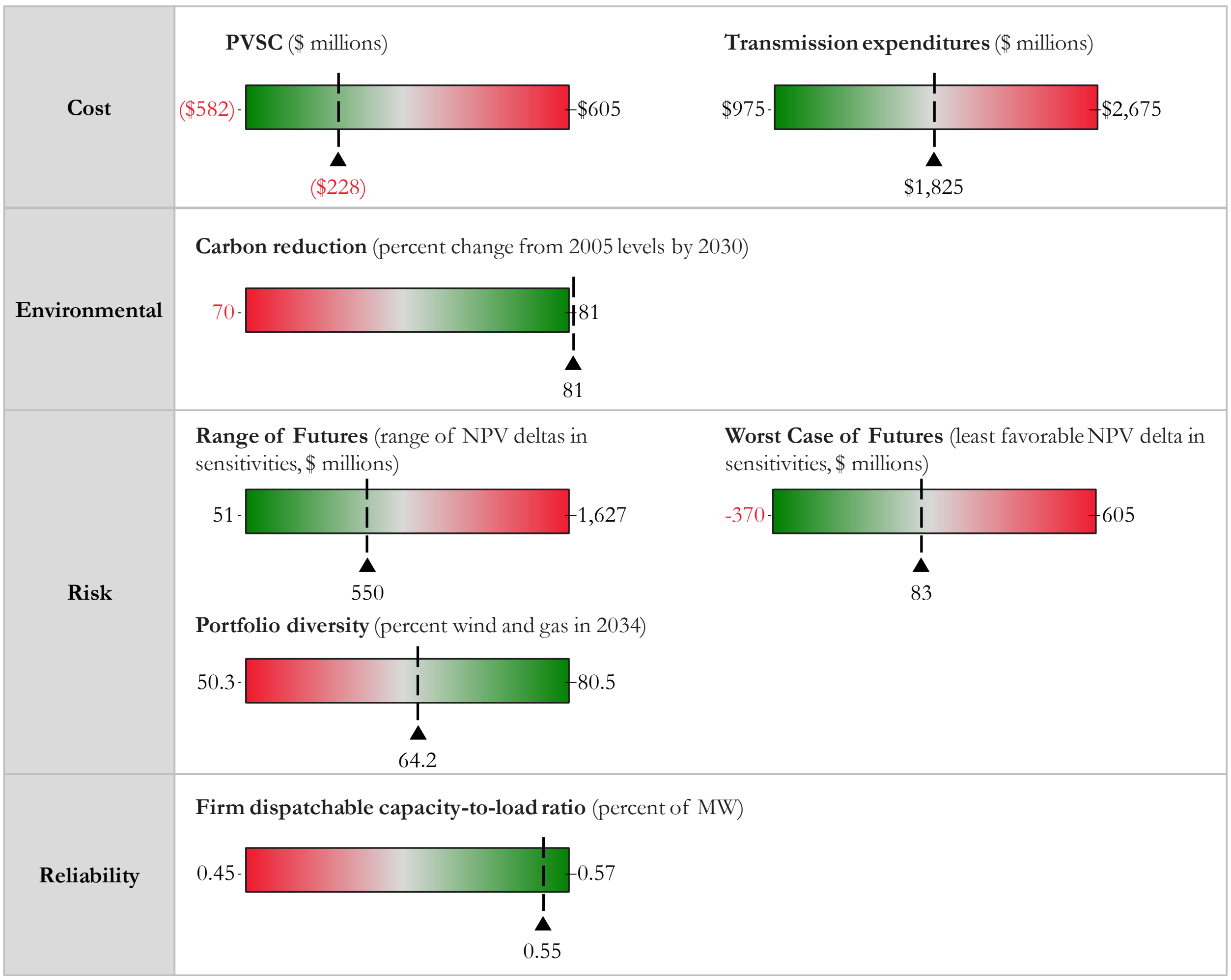
Table 2-5: Scenario Modeling Portfolio Scorecard

Objective	Indicator Metric	Definition
Cost	Base PVSC	Traditional NPV measure of total 2020-2045 PVSC costs, to determine least cost baseload scenarios. Scenarios showing cost savings are preferred.
	Transmission expansion costs	Comparative cost required to build transmission to accommodate renewable expansion in a given portfolio. Estimated using transmission interconnection cost assumptions per MW of capacity additions.
Environmental	Carbon Emissions Reduction	Evaluates the percentage of carbon reduction, relative to 2005 levels, achieved by 2030 in comparison to our 80 percent reduction goal. Given that modeling in the Supplement no longer imposes a constraint on achieved carbon reduction, this is now a key distinguishing feature between scenario results.
Risk	Worst Case Futures Sensitivities Cost and Range of Outcomes	Measure of worst-case potential cost as well as the range of outcomes across the Futures sensitivities, and thus provides insight into plan cost risk. Plans still showing cost savings in worst case Futures Sensitivities and a tighter range of outcomes across all Futures are preferred.
	Portfolio Diversity	Assesses the share of total portfolio generation in 2034 from wind and from natural gas. Portfolio diversity reduces the risk that a disruption to any one resource will result in customer exposure to market or reliability risks.
Reliability	Firm, Dispatchable Resource to Peak Load Ratio	Evaluates the share of peak load that we are able to serve without relying on NSP system use-limited and variable resources, or off-system market energy and capacity purchases. This measure helps us identify market exposure in the event variable and use-limited resources are unavailable for a period of time.

Figure 2-15 below is a full scorecard summary containing all of our key metrics. We evaluated the baseload scenarios across these metrics in the course of selecting our Supplement Preferred Plan. The bars for each metric within the figure below plot

Scenario 9's performance relative to the range of outcomes from the other fourteen baseload scenarios. Scenario 9 performs well on societal cost and carbon reduction measures, which are the key indicators on which we selected it as the basis of our initial Preferred Plan. And in fact, in our EnCompass analysis, Scenario 9 achieves the highest carbon reduction in 2030 of any scenario tested. Given this high performance on key measures of PVSC, carbon reduction, and reliability – and average performance on other cost and risk indicators – we believe that Scenario 9 is a reasonable choice for our Preferred Plan. A more detailed walkthrough of our evaluation of each planning objective, and additional rationale for the selection of Scenario 9, is included below.

Figure 2-15: Scenario 9 Performance on Key Scorecard Metrics



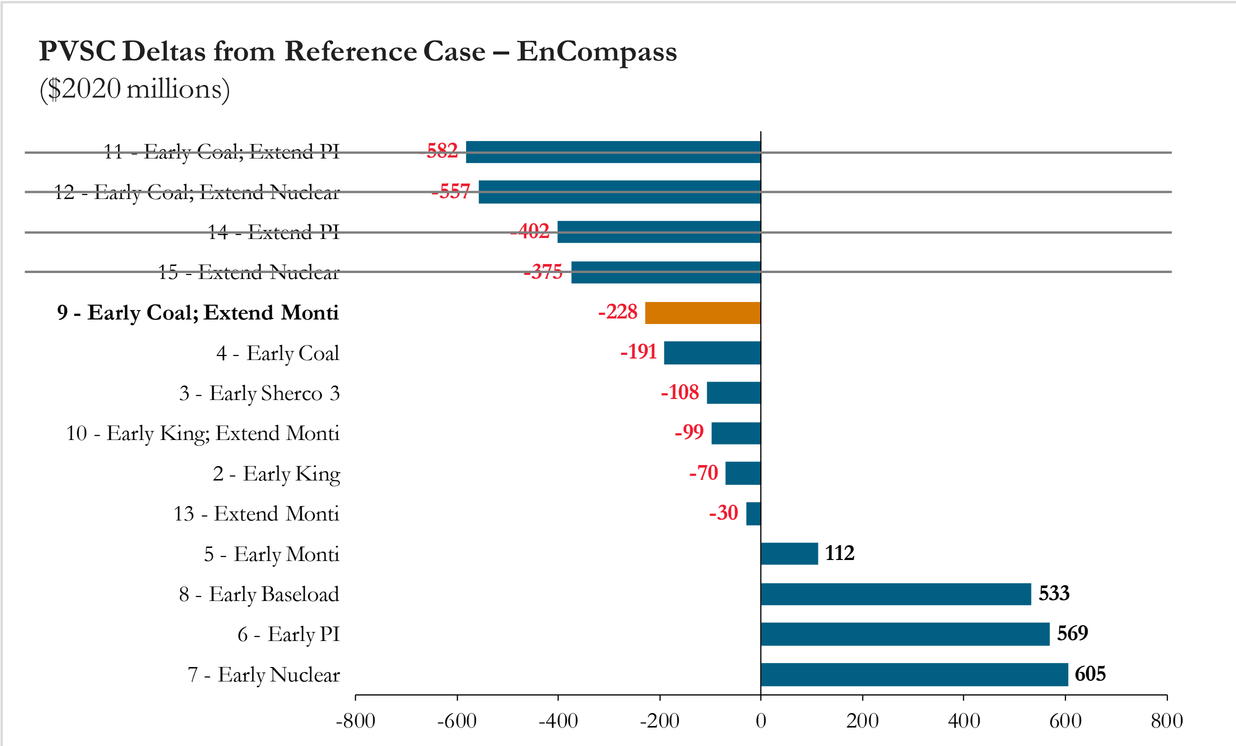
a. Cost

i. PVSC

As noted above, plans that favored early coal retirements and nuclear extensions are generally the lowest cost plans in both Strategist and EnCompass results. As discussed above, we use net present value deltas as primary indicators of a given scenario's economic favorability, because they represent our best understanding of the long-term savings or costs our customers would incur under each plan, relative to the Reference Case's "business as usual" approach.

Consistent with our modeling results in our initial Preferred Plan, this updated Scenario 9 is not the absolute least cost of our fifteen scenarios. All of the lesser cost scenarios include an extension of Prairie Island's operating license, which does not expire until the end of the planning period. As a result, we believe it is a prudent course of action to select a scenario that provides option value for achieving those lower cost scenarios while also deferring a final decision on Prairie Island extension at this time. In other words, selecting this updated Scenario 9 as our Supplement Preferred Plan still allows for a transition to one of the scenarios including Prairie Island extension in the future, if future resource planning analysis leads to the same conclusion. As discussed further in Chapter 3, the five-year action plans for both Scenario 9 and Scenario 12 (Early Coal; Extend Nuclear) are effectively identical. Thus, for the purposes of this Supplement, we continue to set aside scenarios that include Prairie Island extension, and Scenario 9 emerges as the least cost remaining option on a PVSC basis.

Figure 2-16: 2020-2045 EnCompass PVSC Deltas from Reference Case



ii. Transmission Expansion Costs

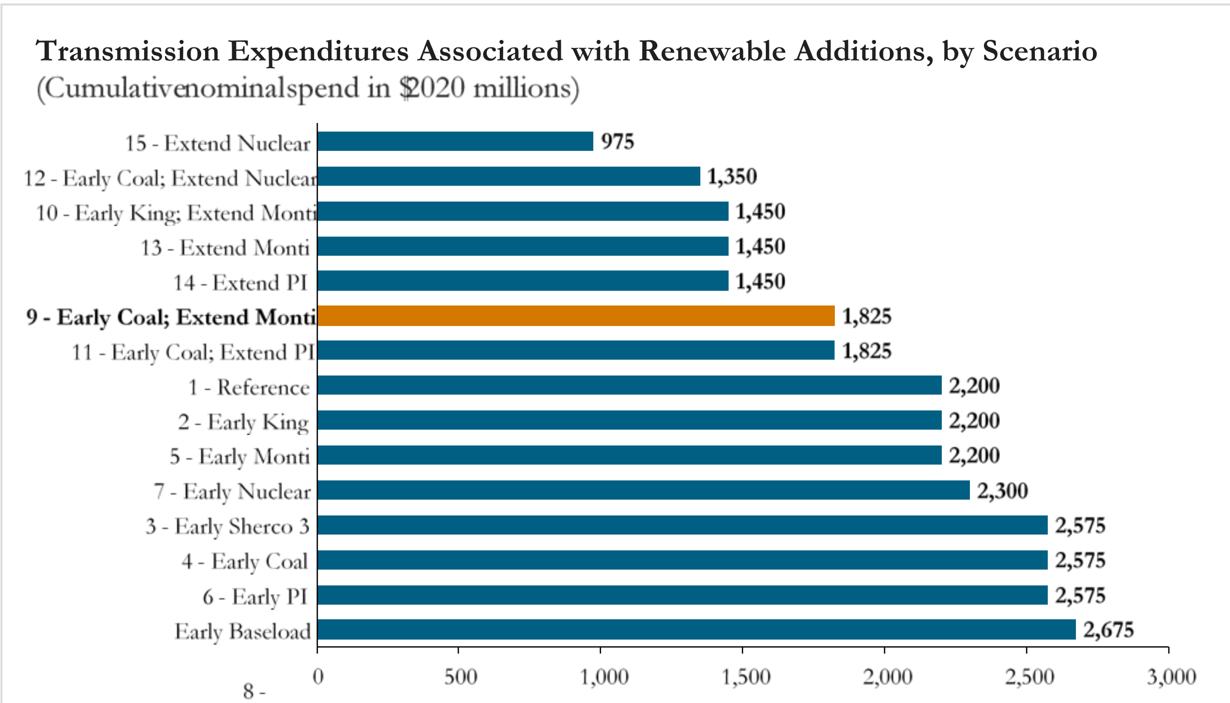
We also evaluate baseload scenarios considering the potential transmission expansion costs associated with the scenarios' modeled generation buildout. This metric is defined as the comparative cost required to build transmission to accommodate renewable expansion in a given portfolio, given transmission cost assumptions included in our modeling.[23] As such, these estimates represent our best estimates at this time of what renewable expansion costs will be in the future, although they are relatively conservative in comparison to results from recent MISO interconnection studies. It is worth noting that we do not presume that transmission spend necessarily is a negative outcome, and we do anticipate future transmission investments that will support our and other utilities' goals.[24] Rather, assessing the transmission expenditures associated with the renewable buildout in each scenario helps us understand potential further cost and risk implications, if these interconnection costs are higher than our

[23] As discussed previously, these costs were estimated using transmission interconnection cost assumptions of $500/kW for wind additions and $200/kW for solar additions. It should be noted that the $/kW transmission interconnection cost assumptions are estimates based on a number of different studies, historical Resource Plan assumptions, and recent MISO queue study results.

[24] In fact, the Company along with several other utilities have asked MISO to examine long-term transmission planning in our region, in order to support utility, policymaker and customers' 2030 goals. Please see Attachment D for additional information.

assumptions or otherwise prohibitive. At this time, there are no formal plans for new, coordinated transmission expansion in the MISO West region, and as a result we assume that transmission expansion costs associated with new greenfield renewable additions could continue to be relatively high in the near term.

Table 2-6: 2020-2034 Cumulative Transmission Expenditures Associated with Renewable Additions

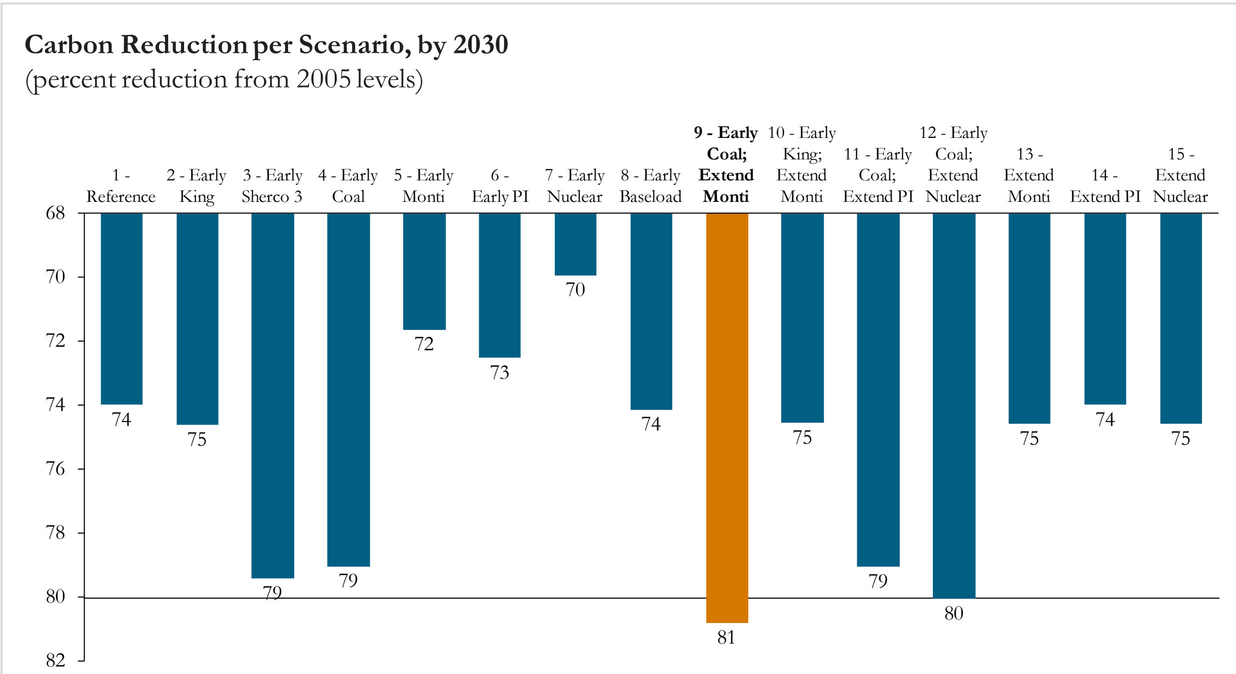


Relative transmission interconnection expenditure results across the fifteen baseload scenarios show that nuclear extension scenarios generally result in lower amounts of required transmission investment. In the scenarios where nuclear does retire, we must replace nearly 15,000 GWh of energy with additional renewables, which drives significant transmission spend. Scenario 9 – which includes Monticello extension, but does not extend Prairie Island – includes transmission expenditures that fall in the middle of the range in relation to other tested scenarios. Pursuing Scenario 9 now also preserves the option for pursue Prairie Island extension in the future, potentially reducing forecasted transmission expenditures.

b. Environmental

Unlike our July 2019 filing, our refreshed baseload scenario results do not include a carbon constraint that requires all scenarios to achieve and maintain an 80 percent reduction in carbon emissions from 2005 levels by 2030. This new approach focuses on allowing the model to optimize with as few constraints as possible, and as such, we see more differentiation between our baseload options on a carbon reduction basis.

Figure 2-17: 2030 Carbon Reduction, from 2005 Levels



As Figure 2-17 above demonstrates, Scenario 9 has the lowest carbon emissions results in 2030, and is one of only two scenarios to achieve the 80-by-30 goal—a significant waypoint as the Company seeks to achieve entirely carbon-free generation by 2050 – and remains below the threshold through the remainder of the planning period.[25] The scenarios that retire nuclear units early are consistently the least-carbon reducing scenarios – underperforming the 80-by-30 goal by 7 percentage points or more – whereas the scenarios that retire all coal units early consistently achieve high levels of carbon reduction. While not shown here, Scenario 9 also achieves the 80-by-30 goal in Strategist results, in 2030 and beyond. As Scenario 9 consistently achieves 80-by-30 in both models, our environmental evaluation further supports selecting Scenario 9 as our Preferred Plan.

[25] We note that Scenario 12 also achieves 80 percent carbon reduction by 2030 in the EnCompass model and maintains the reduction, with the exception of a small emissions increase in 2031. Subsequent testing has shown that this increase can be avoided without meaningfully impacting costs, with only minor adjustments to how resources in this Scenario dispatch.

c. Risk

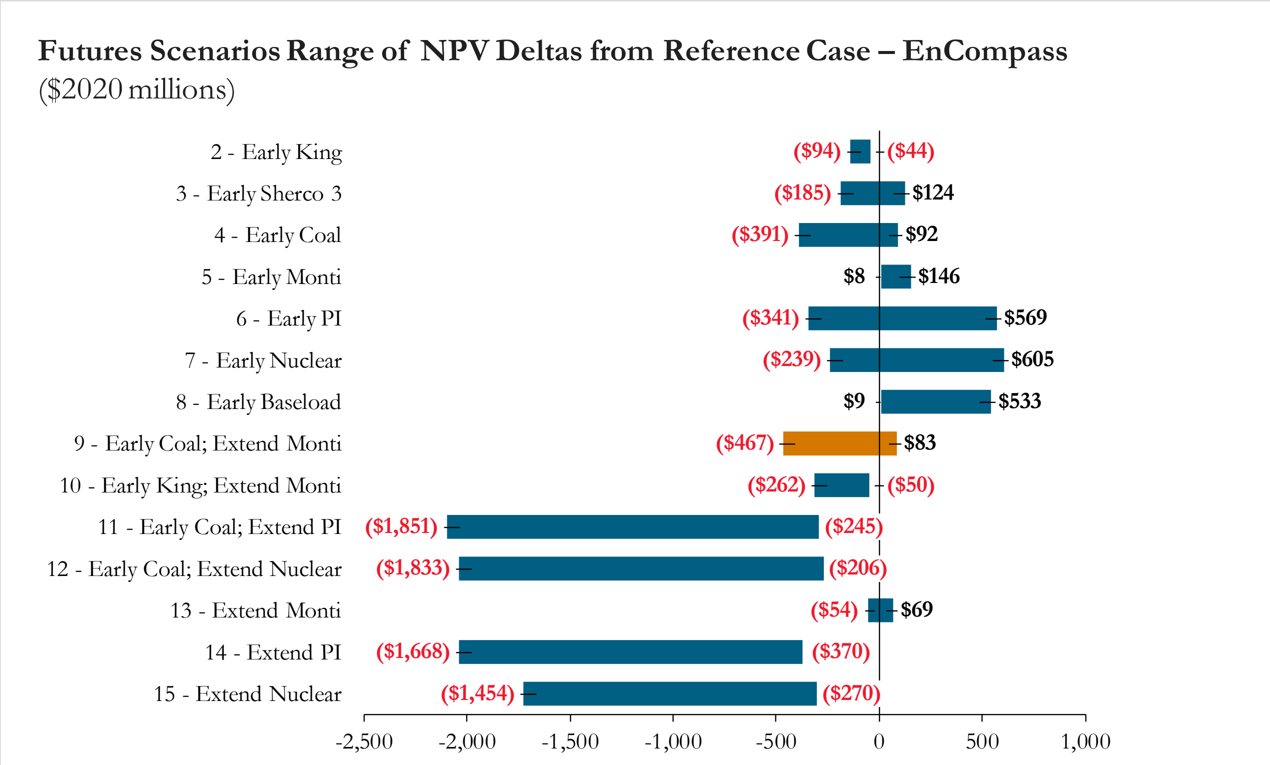
To assess the level of risk associated with the various baseload scenarios, we focused on two specific areas: scenario performance under Futures sensitivities and portfolio diversity metrics.

i. Risk: Futures Scenario Performance

The Futures Scenarios sensitivities provide insights into portfolio risk by showing how each of the respective baseload scenarios perform under different potential futures with very different, but plausible, assumptions. With early coal retirements and nuclear extension options receiving the bulk of the focus in this Resource Plan, it is important to analyze how sensitive these options are to either of our bookend Futures Sensitivities (High Electrification and High Distributed Solar) discussed above. To examine each scenario's relative performance, we examine which scenarios experience the widest variation across Futures results.

Figure 2-18 below provides a summary of the Futures Scenario results. Under all of these Futures Scenarios, Scenario 9 continues to provide savings relative to the Reference Case on a PVSC basis. PVRR results indicate costs relative to the Reference Case, but these are relatively small and do not account for carbon costs. We also note that the range of high to low results for Scenario 9 is relatively small compared to several other scenarios. Taken together, we believe these findings indicate that Scenario 9 is robust under a range of potential future conditions. It is also worth noting that, after setting aside scenarios that include Prairie Island extension, Scenario 9 is one of the most attractive scenarios available not only under Base PVSC assumptions, but a range of Futures.

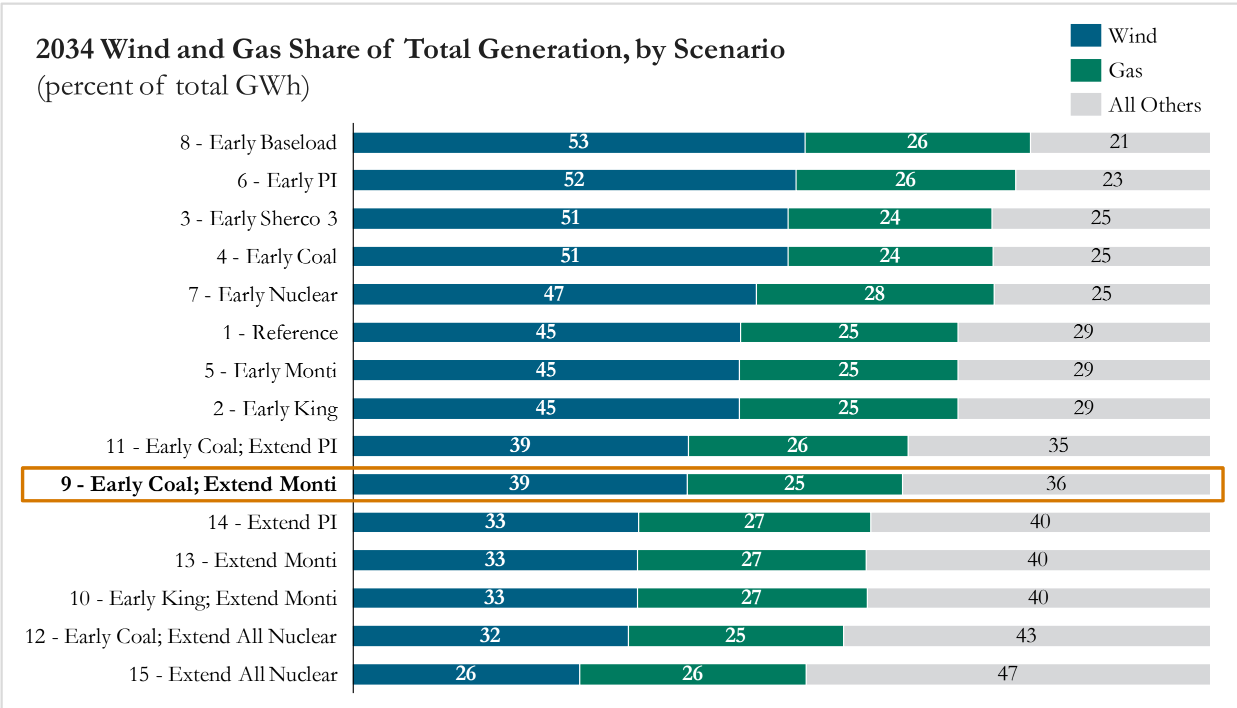
Figure 2-18: Futures Scenarios Range of NPV Deltas from Reference Cases



ii. Risk: Portfolio Diversity

As noted above, portfolio diversity is a helpful risk measure, to ensure our future resource mix is not overexposed to volatility of any given fuel type. In most of our baseload scenarios, our modeled portfolio mix is made up primarily of renewable energy –particularly wind – and natural gas. To measure portfolio diversity, we therefore assessed the maximum amount of energy from these two resource types in each of the respective baseload scenario portfolios. We focused on results from the year 2034 as it is the last year of the Planning Period and typically represents the year in which the most generation replacement has occurred; thus, it is generally the year with the greatest wind and natural gas exposure.

Figure 2-19: 2034 Portfolio Concentration, as Measured by Percent of Total Generation from Wind and Natural Gas



As Figure 2-19 demonstrates, there is much greater variability in the amount of wind energy as a percentage of 2034 total generation than natural gas-fired energy. Despite widely differing retirement dates for existing coal and nuclear plants, all fifteen baseload scenarios present a similar level of risk when it comes to natural gas exposure. The wind energy portfolio concentration, on the other hand, varies widely among the scenarios ranging from 26 percent to 53 percent. Baseload scenarios with higher wind exposure generally include early coal retirements, where nuclear units are not extended. As expected, the baseload scenarios with lower wind energy exposure include the scenarios where nuclear units are extended.

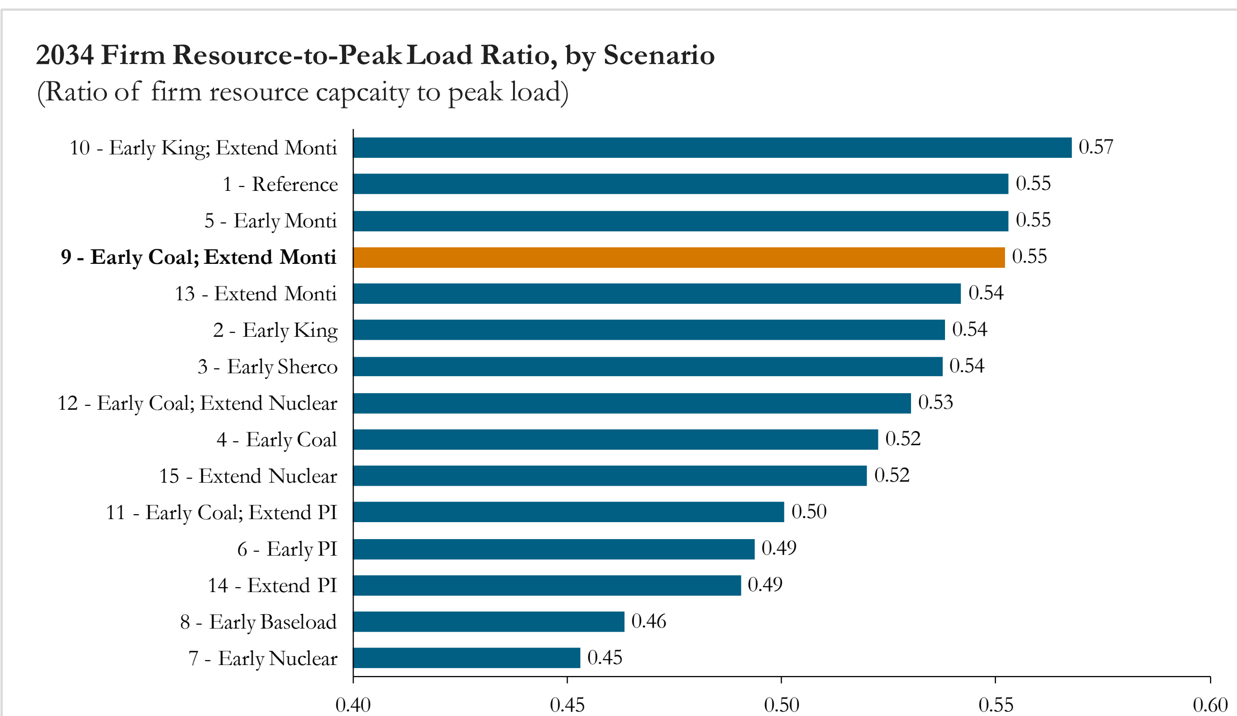
We believe an examination of wind energy concentration helps highlight the important role that nuclear extension plays in preserving generation portfolio diversity and ensuring a more balanced energy mix that still achieves high levels of carbon reduction. These results further support selection of Scenario 9 as our Supplement Preferred Plan as well. Extending Monticello's operation helps maintain greater portfolio diversity, reducing some of the inherent risks associated with high levels of wind concentration, including forecasting error risk and the potential transmission expansion cost exposure discussed previously.

d. Reliability

In our July 2019 filing, all baseload scenarios achieved acceptable levels of reliability, as measured by the amount of firm dispatchable resources available to serve customers. However, we included a pre-set Reliability Requirement in our modeling to achieve this outcome. As we have now removed that Reliability Requirement, capacity expansion modeling returns varying levels of firm dispatchable resource additions across scenarios. We believe assessing the firm dispatchable resource-to-peak demand ratio provides valuable information regarding each portfolio's reliability and risk, because it indicates how much of our customer load we can support with native (i.e. owned or firm contracted) resources that are available to dispatch to their maximum capacity on demand. These include nuclear, coal, and natural gas resources (including combined cycle and combustion turbines). We also include our hydro and biomass resources as they have relatively dependable and consistent energy output.

While current MISO Resource Adequacy rules do not include any requirements for these traditional firm resources, per se, we believe higher firm resource-to-peak ratios help minimize the risk of loss of load events. They also ensure that we are hedged during periods of extreme MISO market demand and/or locational marginal price (LMP) spikes.

Figure 2-20: Firm Dispatchable Resource-to-Peak Load Ratios in 2034



The Firm Dispatchable-Resource-to-Peak ratios for the fifteen baseload scenarios fall within a range between 0.45 and 0.57, and Scenario 9 achieves near the top of the range, with similar results to, for example, the Reference Case. This is a notable outcome in context of other scorecard results, because while Scenario 9 retires all of our coal generation by 2030, it continues to maintain this measure of reliability while achieving favorable PVSC savings results and our carbon reduction goals.

It is important to note here that – while firm-resource-to-peak ratio is a helpful metric as a proxy for reliability – we believe additional hourly reliability testing on specific expansion plan portfolios is needed to confirm that they offer sufficient resources to minimize loss of load risk and maintain MISO's reliability standards.[26] We have provided some of our preliminary findings in the following section on Preferred Plan Sensitivities, in which we have used the EnCompass model's 8,760-hour modeling capabilities to attempt to test select portfolios for energy adequacy and highlight potential reliability concerns. Both EnCompass and Strategist solve for capacity expansion resources in a somewhat simplified dispatch manner based on static annual capacity accreditation assumptions input into the model, typical weather year shapes for load and renewable generation, and a limited number of hours per year. Thus, the capacity expansion optimization itself does not automatically ensure the selection of a fully reliable portfolio under all conditions. EnCompass production cost modeling provides additional analysis capabilities to better test the reliability of specific portfolios, potentially indicating a need for incremental resources to ensure reliability is maintained and loss of load risk is minimized. We have conducted some preliminary reliability analyses on the Supplement Preferred Plan and discuss those results in Section 4.c below as well as in Attachment A, Section XI: Supplement Preferred Plan Sensitivities – Reliability Analyses.

4. *Preferred Plan Sensitivities*

After we determined that baseload Scenario 9 would form the basis of our Supplement Preferred Plan, we took a final step of testing that Plan on several additional sensitivities. The full results of these and other sensitivity tests are included in Attachment A, Section X: Modeling Scenario Sensitivity Analysis – PVRR and PVSC Summary, but we highlight three key tests below. First, in response to Commission direction, we tested Scenario 9 using sensitivities that examined 1) the economic costs or benefits of renewable-plus-storage hybrid resources, and 2) the economics of different Sherco CC sizes, with two smaller size options and one larger. These sensitivities were tested in both Strategist and EnCompass, although we focus on EnCompass results below. We also performed an hourly reliability assessment

[26] For example, the 1 day in 10 years (1-in-10) LOLE standard.

analysis on Scenario 9 and several sensitivity portfolios, to help us understand portfolio performance under actual historical meteorological conditions that reflected more variation than the default planning assumptions used in our capacity expansion models. We tested these sensitivities in EnCompass only, as Strategist is not capable of performing 8,760-hour analysis.

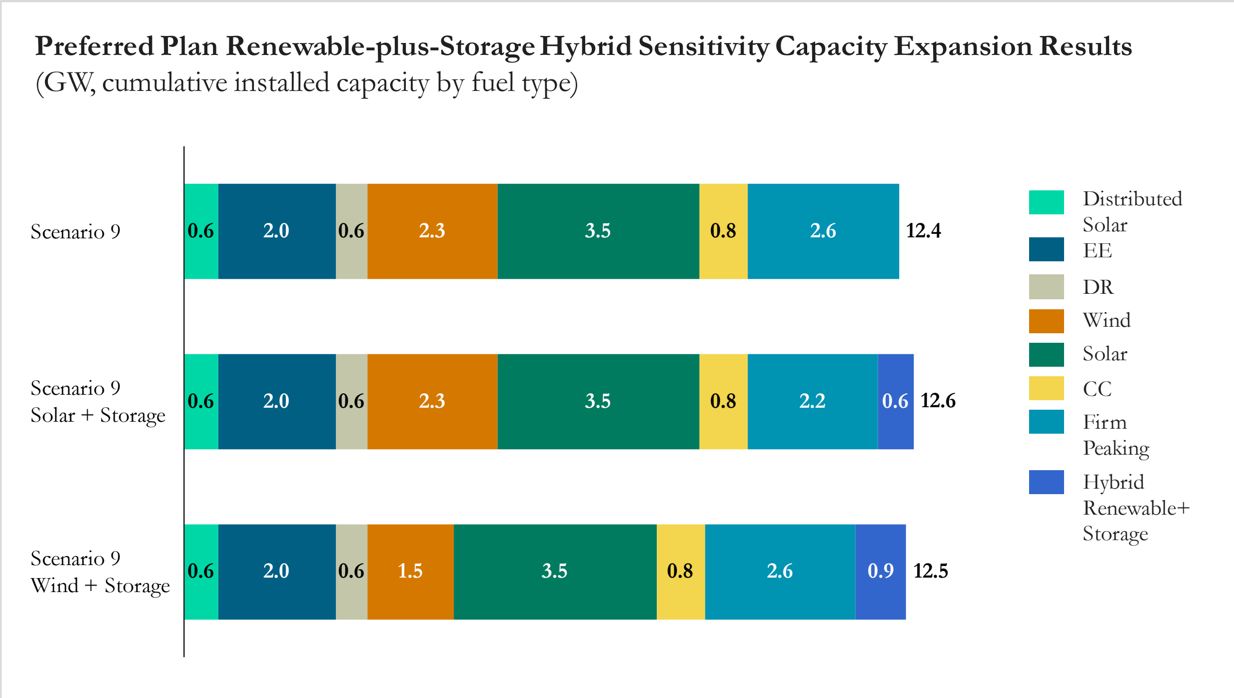
We note that we have not proposed changes to our Supplement Preferred Plan based on these sensitivity results, rather provide them for the Commission's and stakeholders' information.

a. Renewables-plus-storage hybrid resources

The Company conducted sensitivities that test the economic viability of replacing some of the wind and solar selected in our Supplement Preferred Plan with hybrid wind-plus-storage or solar-plus-storage resources. These options are not examined in the initial capacity expansion modeling for process purposes, as adding too many generic resource options to the model optimization slows the modeling process. However, we can evaluate whether a hybrid option is an economic alternative to standalone renewables by manually replacing some of the wind and solar the plan selects with hybrid wind-plus-storage or solar-plus-storage options.

To conduct this test, the Company took the EnCompass optimized expansion plan for Scenario 9 (the Supplement Preferred Plan) and manually replaced the first occurring solar generic resource with a combined solar-plus-storage resource. We then reoptimized the expansion plan around this new, manually included resource. Following the same process, we tested replacing the first occurring generic wind resource with a combined wind-plus-storage resource. Given the additional capacity associated with the storage component of the hybrid resource, the re-optimized result typically either deferred to a later date, or avoided, firm peaking capacity (modeled as CTs), relative to Scenario 9.

Figure 2-21: Preferred Plan Sensitivity Testing – Hybrid Renewables-plus-Storage Capacity Expansion Results



After the capacity expansion modeling step, we then conducted a full 8,760 production costing run on this sensitivity just as we did with the baseload study, in order to evaluate the cost and dispatch data and compare to the Supplement Preferred Plan cost outcomes. These analyses show that – given current assumptions regarding technology costs and our system needs – hybrid renewables-plus-storage resources are not expected to be a cost-effective alternative to standalone renewables. These results are driven by the relative forecasted prices for firm peaking, solar, and storage resources. In both hybrid cases, the storage addition replaced either firm peaking (for the solar hybrid) or solar (for the wind hybrid). That said, these results are based on forecasted technology prices that may change in the future. We fully intend to closely monitor developments for hybrid resource options, both in terms of price and performance, and will adapt our solicitations, modeling approaches and resource procurement accordingly as conditions change.

Table 2-7: Supplement Preferred Plan Hybrid Sensitivities PVSC and PVRR Deltas from Scenario 9

Scenario	PVSC Deltas ($2020 millions)	PVRR Deltas ($2020 millions)
Scenario 9 (Supplement Preferred Plan)	--	--
Scenario 9 Solar-plus-Storage	$29	$44
Scenario 9 Wind-plus-Storage	$212	$182

b. Sherco CC Size Sensitivities

Our Supplement Preferred Plan includes a Sherco CC sized at approximately the same capacity as "proposed to the Public Utilities Commission in docket number E-002/RP-15-21[.]"[27] However, in response to Commission direction, we have developed three different size options – two smaller units and one larger one – to examine whether a differently sized and configured unit would be more economically beneficial. The process we use to test these size options is similar to that which we used for the hybrid renewable-plus-storage options. Starting with Scenario 9 we conducted three EnCompass optimization runs that replaced the default Sherco CC with one of the three alternative sizes (and their associated costs and operational specifications) in each run. This process allowed us to examine how the capacity expansion portfolio would respond to each size alternative. We then conducted a full 8,760-hour production costing simulations for each alternative. Specific detailed assumptions associated with the different CC size options are included in Attachment A, Section IV: Modeling Assumptions and Inputs.

[27] Laws of Minnesota 2017, Chapter 5—H.F. No. 113, section 1.

Figure 2-22: Supplement Preferred Plan Sensitivity Testing - Sherco CC Size Variation Capacity Expansion Results

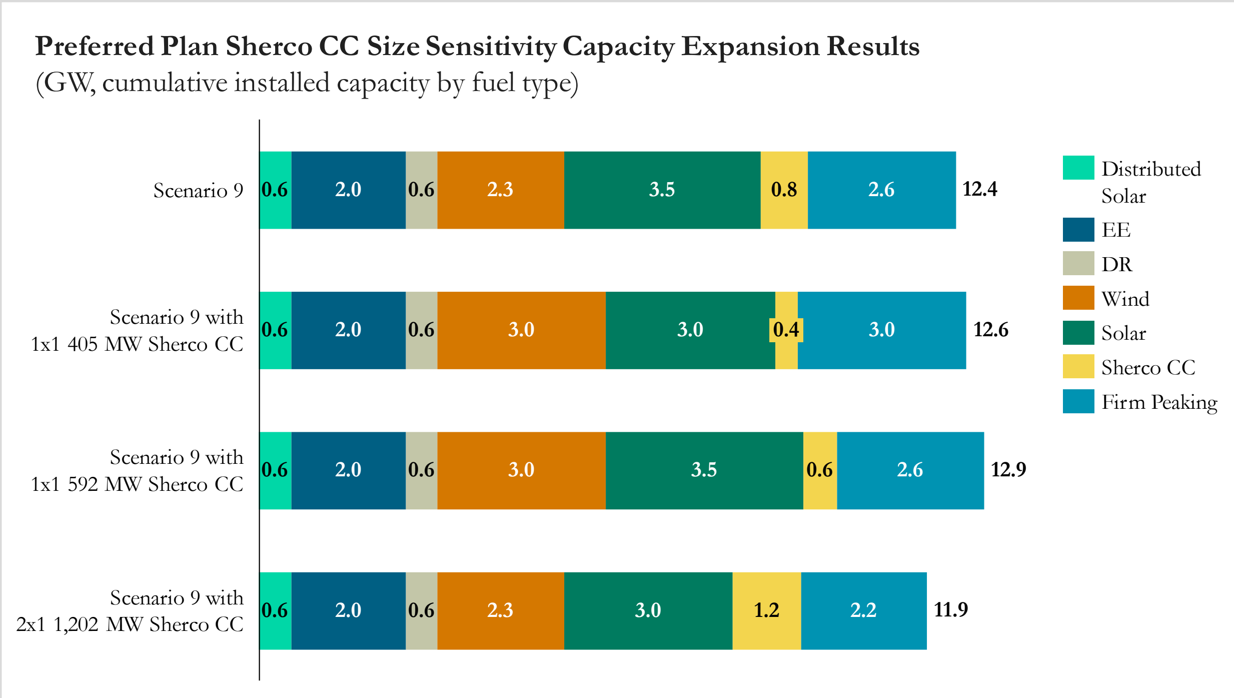


Table 2-8: Supplement Preferred Plan Sherco CC Size Variation Sensitivities PVSC and PVRR Deltas as Compared to Scenario 9

Scenario	PVSC Deltas ($2020 millions)	PVRR Deltas ($2020 millions)
Scenario 9 (Supplement Preferred Plan)	--	--
Scenario 9 with 405 MW 1-by-1 Sherco CC	$193	$234
Scenario 9 with 592 MW 1-by-1 Sherco CC	$32	$38
Scenario 9 with 1202 MW 2-by-1 Sherco CC	($349)	($354)

Our analysis shows that a larger Sherco CC sized at approximately 1,200 MW (installed capacity) would be more cost effective on both a PVSC and PVRR basis than our default option. The larger CC provides about $350 million in PVSC and PVRR savings relative to the base option, whereas the two smaller options both drive increased costs. We expect this outcome is attributable to economies of scale associated with constructing and operating a larger generating unit. Along with similar gas demand costs, we would expect comparable levels of fixed O&M and consistent operational characteristics across the size options, and thus the larger units are more cost efficient. In addition, the cumulative expansion plans in Figure 2-22 show that the larger CC helps avoid other capacity additions – including a CT – relative to the other size options, yielding additional cost savings.

We note that, while Encompass and Strategist results generally aligned for most of the sensitivities, the model results diverged in Sherco CC size testing. Whereas EnCompass results showed that the largest CC option was the most economic, Strategist results showed that the 592 MW size option yielded the most favorable PVSC outcome, at approximately $45 million in savings relative to the Strategist -modeled Scenario 9 capacity expansion plan. The smallest and largest size options both yielded added cost in Strategist modeling. This difference is likely attributable to the different mix of capacity expansion portfolios in the base Scenario 9 modeling in EnCompass versus Strategist. Strategist simulations yielded a much more solar-heavy Scenario 9 portfolio that erodes some of the energy value of the default-sized Sherco CC option.

c. Reliability Testing

Finally, we conducted several reliability-related sensitivity analyses on the Supplement Preferred Plan, to test the robustness of Scenario 9 and three sensitivities under different historical conditions. EnCompass capacity expansion functionality optimizes a portfolio that is energy and capacity adequate – including considerations for market availability – under given assumed load and resource availability conditions. In order to evaluate whether the Supplement Preferred Plan, or variations on it, could result in shortfalls if those assumptions do not hold true, we tested the base Supplement Preferred Plan and three Scenario 9 sensitivities with load and renewable shapes associated with a historical year's results that exhibited more volatility as compared to our base assumptions; in this case 2019. We ran 8,760-hour simulations for each of the four portfolios below for the year 2034 and then assessed portfolio performance across four general categories of reliability metrics. These metrics including native capacity shortfalls, flexible ramp adequacy, market import risk as well as some standard reliability metrics included in the EnCompass model results.

Table 2-9 lists the four different plans that were evaluated, as well as the primary rationale for selecting them.

Table 2-9: Reliability Sensitivities Tested

Capacity Expansion Plan Tested	Description and Rationale for Testing
Scenario 9 – Supplement Preferred Plan	To ensure energy adequacy of the Supplement Preferred Plan in under different historical resource and load shape assumptions.
Scenario 9 – High Distributed Solar Future Sensitivity	Scenario contains low technology cost assumptions, so the 2034 portfolio contains a relatively higher share of batteries and substantially less firm dispatchable generation Scenario 9 under default assumptions.
Scenario 9 – High Electrification Future	Scenario contains low technology cost assumptions and high load, so the 2034 portfolio contains more capacity overall – primarily a high proportion of batteries and variable renewables – and less firm peaking capacity than Scenario 9 using default assumptions.
Scenario 9 – 50 Percent Solar ELCC	Scenario assumes a fixed 50 percent capacity credit for solar in all years, which significantly increases incremental solar additions and reduces firm peaking capacity selected but results in approximately the same amount of storage as Scenario 9 under default assumptions.

Below is a summary table of our key findings. A more detailed discussion of our approach and results can be found in Attachment A, Section XII: Supplement Preferred Plan Sensitivities – Reliability Analyses.

Table 2-10: Summary of Reliability Metrics Analyzed, by Test

	Native Capacity Shortfall Metrics		Flexible Resource Adequacy Metric	Maximum Import Metric
Expansion Plan Tested ***(Test Load and Resource Shapes)***	**Number of Native Capacity Shortfall Events**	**Longest Shortfall Event (hours)**	**Maximum 3 – Hour Upward Ramp and Occurrence Month (MW)**	**Hours >95 Percent of 2,300 MW Import Limit**
Baseline – Scenario 9 *(Default)*	0	0	4,760 (February)	9
Scenario 9 *(2019)*	4	2	5,506 (June)	158
Scenario 9 – High Distributed Solar Future *(2019)*	14	5	7,221 (June)	157
Scenario 9 - High Electrification Future *(2019)*	21	6	7,152 (March)	674
Scenario 9 – 50 percent ELCC *(2019)*	159	22	7,239 (January)	311

While we are still working to fully understand all of the EnCompass model's capabilities with respect to reliability analyses, we believe the above findings indicate potential risks associated with portfolios that rely more heavily on variable renewables and use-limited resources. As demonstrated in the table above, the Supplement Preferred Plan exhibits few to no issues under the typical conditions that were used as a default assumption for baseload scenario modeling. When evaluated under the 2019 actual historical conditions, we did encounter more periods in which native capacity is insufficient to serve our customers and our import capabilities were at maximum levels, but these events were still relatively uncommon.

The three other portfolios, however, produce more reliability challenges when evaluated under the 2019 actual shapes, either with the magnitude or length of native capacity shortfalls, 3-hour ramping needs, or others. In particular, the "Scenario 9 – 50 Percent ELCC" portfolio experiences the highest number and duration of native load shortfalls, and a high 3-hour ramp. We believe this evaluation helps to confirm that our use of a declining ELCC metric for solar is appropriate. We also note that the longest shortfall duration in this test scenario far exceeds the capability of a four-hour battery to mitigate and indicates further examination regarding a 100 percent ELCC assumption for battery energy storage is warranted.[28]

In conclusion, we believe these sensitivity results reinforce the importance of assessing our system's reliability as we retire coal units and add renewables, and we will continue to develop our approach to reliability analyses using EnCompass in the future. That said, when evaluating our full body of modeling results, including these reliability results, we believe they support the conclusion that Scenario 9 is an appropriate choice to form the basis of our Supplement Preferred Plan. In the next Chapter, we discuss the elements comprising the Supplement Preferred Plan.

[28] We note these findings – regarding the appropriateness of declining ELCC assumptions as solar and energy storage penetration increases – are consistent with E3 modeling presented in our initial Resource Plan filing in July 2019. Please refer to Appendix P2 of our initial filing for further discussion.

SECTION 3: SUPPLEMENT PREFERRED PLAN

As discussed in the last chapter, in preparing this Supplement, the Company conducted extensive additional expansion modeling using both Strategist, a tool we have historically relied on, and EnCompass, a new tool that provides the additional capability of modeling our system on an hourly basis. We have also updated modeling assumptions and adjusted some of our modeling approaches to address concerns raised by some parties with the modeling used to create our initial Preferred Plan from our June 2019 filing.

Based on this additional modeling in both EnCompass and Strategist, we developed our Supplement Preferred Plan, which still shares the same key elements as the initial Preferred Plan. Our Supplement Preferred Plan continues to include early retirements of our baseload coal units, extension of the license for Monticello, and significant renewable additions after 2024. We believe the Supplement Preferred Plan best positions the Company to achieve our ambitious carbon reduction goals while maintaining a reliable system and keeping our customers' bills low and, therefore, is in the public interest and should be approved.

Below, we discuss the components of our Supplement Preferred Plan, our Five-Year and Long-term Action Plans under the Supplement Preferred Plan, a comparison of modeling results under both EnCompass and Strategist, the components of our North Dakota expansion scenario, and why the Supplement Preferred Plan is in the public interest.

Before discussing the specific elements of the Supplement Preferred Plan, however, we note that, on June 17, 2020, in Docket No. E,G999/CI-20-492, in response to the Commission's Notice of Reporting Required by Utilities, the Company filed a Report laying out a number of proposed investments the Company could make to assist in Minnesota's economic recovery from the COVID-19 Pandemic (June 17 Relief and Recovery Report). Although these investments are not specifically included in the Supplement Preferred Plan, we believe they are consistent with the direction we have set out here, as discussed in our June 17 Relief and Recovery Report and below.

A. Supplement Preferred Plan

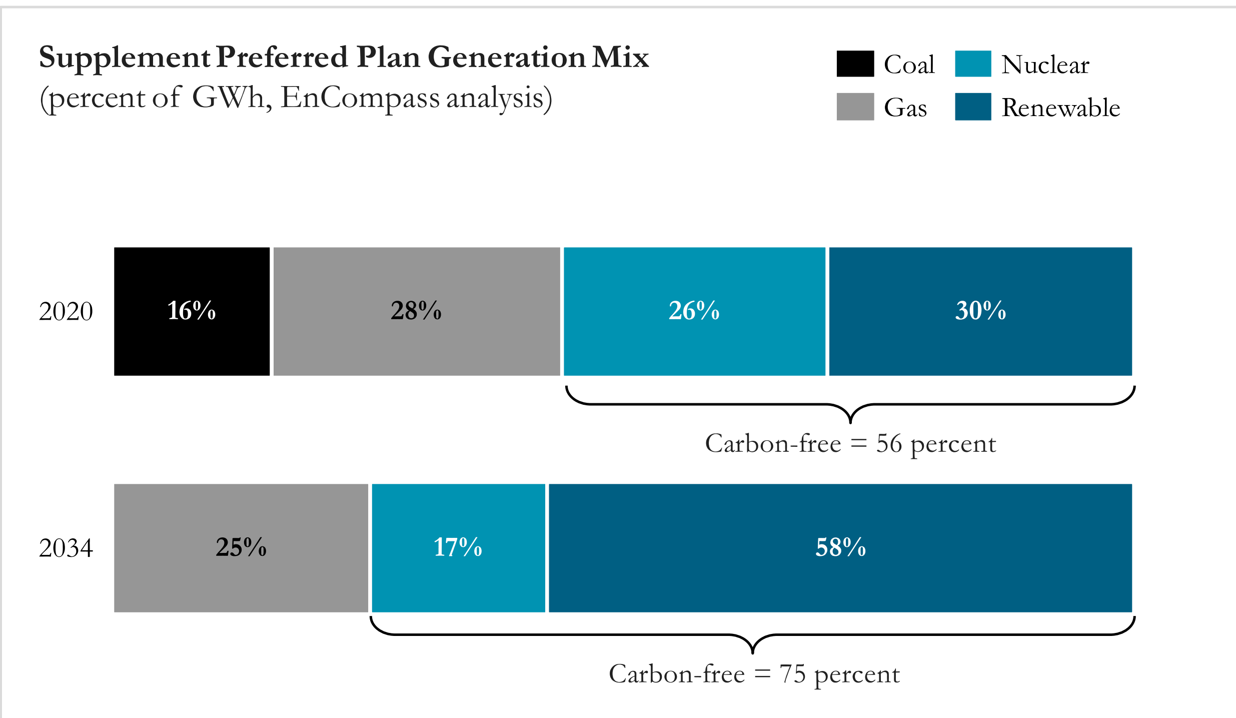
Our Supplement Preferred Plan maintains the vision for the future of the Company's system that was included in our initial Preferred Plan. We are continuing to propose the following core components:

- 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 DR resources;
- Continued operation of our nuclear plants at least until the end of their licenses and extending operation of the Monticello nuclear plant to 2040; and
- Construction of a new CC at our Sherco site.

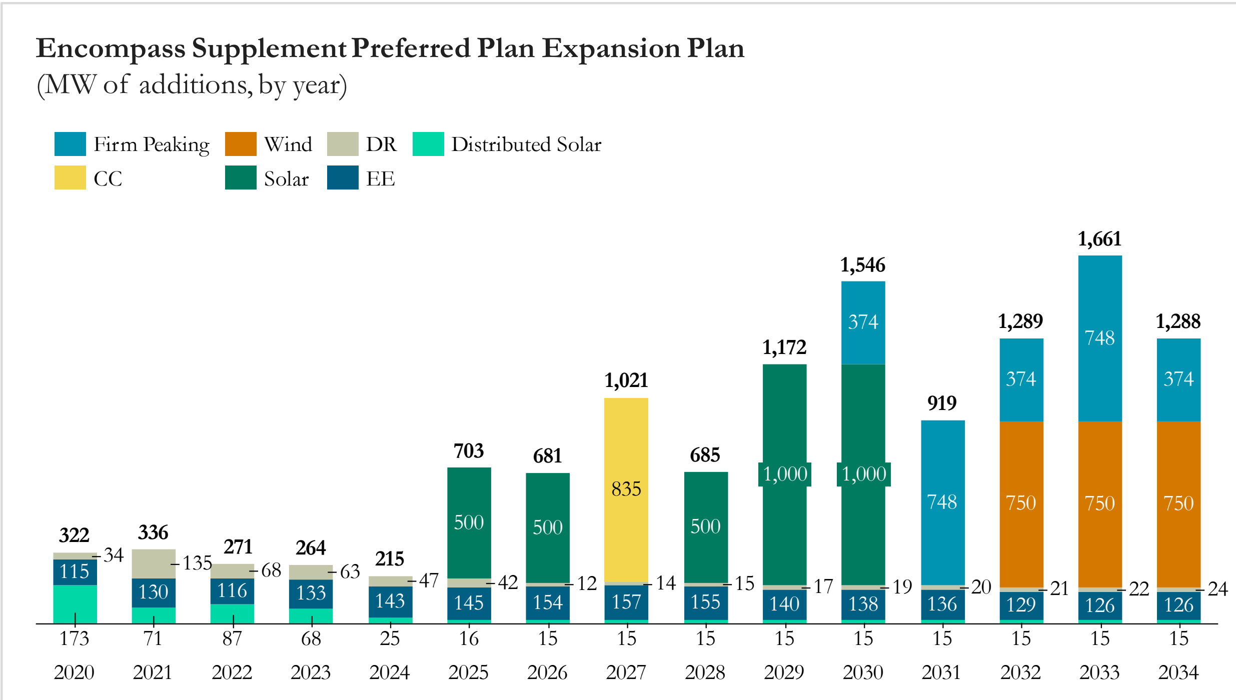
The fleet transformation reflected in the Supplement Preferred Plan will achieve a substantial reduction in CO_2 emissions, meeting our corporate goal of an 80 percent reduction in emissions from 2005 levels by 2030, and setting the Company on a path to achieve 100 percent carbon-free generation by 2050. Figure 3-1 below compares the Company's current generation mix to the Supplement Preferred Plan's projected generation mix by 2034 and their respective percentages of carbon-free generation.

Figure 3-1: Supplement Preferred Plan Generation Mix 2020-2034



As shown above, like our initial Preferred Plan, the Supplement Preferred Plan continues to facilitate our transition away from coal-fired generation by 2030. To replace this capacity, we are planning significant renewable energy additions, to continue operating our nuclear fleet and extending our Monticello operating license, the addition of a natural gas CC at Sherco, substantial EE and DR additions, and a sufficient amount of firm peaking resources to maintain reliability. Figure 3-2 below presents the amount and timing of the resource additions that comprise our Supplement Preferred Plan.

Figure 3-2: Supplement Preferred Plan Resource Additions



Below, we lay out the resource changes we are planning from 2020-2034 in the Supplement Preferred Plan.

1. *Renewable Additions*

Renewable additions continue to be the cornerstone of our Supplement Preferred Plan, which shows additions consistent with the initial Preferred Plan by 2034. The Supplement Preferred Plan proposes to add approximately 3,500 MW of cumulative utility scale solar resources and 2,250 MW of wind by 2034. This represents an increase over the total renewable capacity proposed in our initial Preferred Plan. We note that, given existing transmission constraints, these significant planned renewable additions will require supporting infrastructure expansion; we incorporated assumed costs of that infrastructure in our modeling. We also recognize that resource diversity helps ensure our system remains reliable, especially given variable renewables are not available on demand, every hour of the day. Therefore, our Supplement Preferred Plan continues to include cost-effective natural gas and carbon-free nuclear generation, which will ensure we are able to continue running a safe and reliable system.

2. Coal Resources

The Supplement Preferred Plan maintains our plan to retire our entire fleet of coal-based generating units by 2030. As with the initial Preferred Plan, not only are we continuing our Commission-approved plan to retire Sherco Units 1 and 2 in 2026 and 2023, respectively, we also are maintaining our proposal to retire the Allen S. King plant at the end of 2028, and we are proposing to retire Sherco Unit 3 at the end of 2029, both several years ahead of their originally planned retirement dates. Our Supplement Preferred Plan also reflects our commitment to offer the King plant—in addition to Sherco Unit 2—into MISO on a seasonal and/or fully economic basis until its retirement.

These plans are not only consistent with our initial Preferred Plan but also the Company's commitments in the MEC/IRP Settlement Agreement filed in Docket No. IP6949, E002/PA-18-702 on May 20, 2019. Notwithstanding the Commission's decision to deny the Company's request to acquire the Mankato Energy Center, we remain committed to the specific agreements laid out in that Settlement, including among other things the early retirement of the King plant and Sherco Unit 3, and seasonal dispatch of Sherco Unit 2 until its retirement in 2023.

As we retire these coal units, we continue to be mindful of the need to maintain a resilient and reliable grid. This informs the inclusion of the Sherco CC and other firm peaking resources in the Supplement Preferred Plan.

3. Nuclear Resources

Like our initial Preferred Plan, the Supplement Preferred Plan proposes to operate the Monticello generating plant through 2040 (ten years longer than its current license), and to continue operation of both Prairie Island (PI) Units at least through the end of their current licenses (PI Unit 1 to 2033 and PI Unit 2 to 2034). Although we acknowledge our current modeling projects incremental benefits by also extending the licenses for the Prairie Island Units, there is time to make a decision around potential extension for Prairie Island later. Moreover, we note that through 2030, the planned additions under both our Supplement Preferred Plan and Scenario 12 –which retires our coal units early and extends all nuclear units –are identical. There is, therefore, very little difference over the next decade in choosing one plan over the other, and reserving decision on Prairie Island has no impact on the potential benefits of a license extension, should we choose that path.

By delaying the decision regarding whether to extend the Prairie Island license, we can ensure that it will be made with more complete information, including outreach and discussions with the Prairie Island Indian Community, experience with the initial phases of planning for the Monticello re-licensing, and continuing efforts to identify a long-term waste storage solution. This path also allows us to dedicate our resources toward the necessary immediate actions, including the extensive work required to prepare for and pursue Monticello license extension.

4. *Combined Cycle Resources*

Our Supplement Preferred Plan continues to include our plan to build an approximately 800 MW combined-cycle unit at the Sherco Plant located in Becker, Minnesota in the mid-2020s.[29] As discussed in our initial filing, continuing to include dispatchable generation on our system is vital to our ability to manage the retirement of our coal units and integrate large amounts of renewables. 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, included as Attachment D1 of our 2015 IRP Supplement;[30] it will primarily offset the retirement of other gas units on our system, including the Cottage Grove facility and Black Dog 5; and it will mitigate impacts to the local community and our employees, and potentially provide improved access to natural gas supplies for communities in Central Minnesota.

5. *Firm Peaking and Black Start Resources*

In addition to the proposed addition of the Sherco CC, our Supplement Preferred Plan proposes to add approximately 2,600 MW of cumulative firm peaking resources at the end of the planning period. These proposed additions are needed 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. As discussed in our initial filing, although we modeled these units as CTs, we are not committing to a specific resource type to meet this need because these units are not needed until the out-years of our current Plan.

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[29] Based on the Commission's decision in Docket No. IP6949,E002/PA-18-702, we are not including an acquisition of MEC in the Supplement Preferred Plan.

[30] Docket No. E002/RP-15-21, SUPPLEMENT – CURRENT PREFERRED PLAN, Attachment D1 (January 29, 2016).

6. Energy Efficiency and Demand Response

Our Supplement Preferred Pan continues to include the EE and DR investments we included in our initial Preferred Plan. The level of EE we continue to propose seeks to achieve savings levels ranging from 2 to 2.5 percent annually, achieving average savings of over 780 GWh of energy in each of 2020-2034, and more than 800 MW of additional demand savings by 2034 when compared to the 1.5 percent level approved in our last Resource Plan. We also are proposing an incremental 400 MW of DR by 2023, as required by the Commission's Order in our last Resource Plan,[31] which grows our DR resources to approximately 1,500 MW total by the end of the planning period.

B. Action Plans

1. Five-Year Plan (2020-2024)

Consistent with our initial filing, our Five-Year Action Plan does not include any incremental capacity additions through 2024. Therefore, our actions in the first five years of the planning period remain focused on addressing previously approved or pending resource additions and retirements, wind repowering, procurement to meet specific customer needs, and growth of DSM programs. Below, we discuss near-term actions by resource type.

Wind. As under our initial Preferred Plan, we are continuing progress on the 1,850 MW of wind generation from our recent acquisitions and RFPs. However, as we have discussed in other filings, the Crowned Ridge II project will now be a 200 MW, rather than 300 MW, wind facility. Additionally, in response to feedback we received regarding the initial Preferred Plan, we did not require our models to select replacement wind resources when existing resources reached the end of their contracts. Instead, the models optimized and selected wind additions between 2032 and 2034, but not during the five-year plan period. We note, however, that the assumptions in the modeling reflected only incremental greenfield resources.

To the extent we encounter opportunities to economically repower existing resources, or if specific customer needs require procurement, we expect to pursue them and submit the plans for approval in separate proceedings. To that end, in our June 17 Report in Docket No. E,G999/CI-20-492, we noted our plan to issue a solicitation for repowering existing wind resources. Although we do not know at this time the

[31] *See* Docket No. E002/RP-15-21. ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE RESOURCE PLAN FILINGS (January 11, 2017) at Order Point 10.

potential magnitude of such projects, we estimate that this could result in an 800-1,000 MW repowering portfolio. This solicitation is designed to identify opportunities to reduce customer costs by displacing existing projects with higher levelized costs. And, although it would necessarily result in existing resource extensions during the first five years of the planning period that were not included in our modeling, it is directionally consistent with the significant renewable additions included in the Supplement Preferred Plan.

Solar. Our Supplement Preferred Plan continues to include significant amounts of large-scale solar resources, in addition to forecasted growth of distributed solar. However, as with the initial Preferred Plan, the initial planned addition of 500 MW does not occur until 2025, which is just outside of our Five-Year Action Plan window. We would need to begin the process of adding these utility-scale resources in the 2023 to 2024 timeframe. We also note that, in our June 17 Report in Docket No. E,G999/CI-20-492, we proposed the addition of up to 460 MW of solar additions to interconnect at the Sherco substation. If approved, this would largely fill the need projected in 2025 in the Supplement Preferred Plan.

Hydro. The Supplement Preferred Plan continues to add an incremental 125 MW of energy and capacity in 2021, through a PPA with Manitoba Hydro previously approved by the Commission in 2011.[32]

Nuclear. The Supplement Preferred Plan continues to include a request to operate our Monticello nuclear unit for an additional 10 years beyond its current license. We plan to initiate a Certificate of Need proceeding in Minnesota, as well as a Supplemental License Renewal process with the Nuclear Regulatory Commission, within the next five years.

Natural Gas andOil Peaking. Consistent with the Commission's October 22, 2019 Order in Docket No. E,G-002/D-19-161, the Company plans to extend the lives of Blue Lake Units 1-4 through 2023. We also continue to plan development activities associated with the Sherco CC during the next five years. Unlike our initial Preferred Plan, however, the Supplement Preferred Plan does not include the MEC acquisition, given the Commission's December 18, 2019 Order denying the proposed acquisition.[33] MEC capacity is included in our plan, via the existing PPAs, through their original expiration dates.

[32] Order Approving Agreements, May 26, 2011 (Docket No. E-002/M-10-633).
[33] *See* Docket No. IP-6949, E-002/PA-18-702, IP-6949/GS-15-620.

Coal. Consistent with our last Resource Plan, we are continuing to work to retire Sherco Unit 2 in 2023 and Sherco Unit 1 in 2026. The Supplement Preferred Plan also continues to propose retiring Sherco 3 and King prior to 2030, consistent with the initial Preferred Plan.

Demand Response. The Supplement Preferred Plan continues to include the acquisition of 400 MW of incremental DR resources by 2023. For this Supplement Preferred Plan, the incremental capacity from this acquisition was included in the baseline portfolio for the capacity expansion optimizations.

Energy Efficiency. The Supplement Preferred Plan continues to include significantly increased levels of EE. For this Supplement Preferred Plan, the incremental capacity and energy from these programs were included in the baseline portfolio for the capacity expansion optimizations.

Additional infrastructure. We continue to plan sufficient supporting infrastructure to facilitate our fleet transformation, ensure grid resilience and reliability, and to enable greater DER and DR resources on our system. For example, we continue to anticipate completing transmission investments, such as the Huntley-Wilmarth project, in late 2021. Additionally, following the Commission's vote on May 29, 2020 to certify the Advanced Metering Infrastructure and Field Area Network components of our advanced grid strategy, we plan to install new electric meters and supporting infrastructure that will, among other things, facilitate integration of DER and DR resources across our service area.

2. *Long-Term Plan (2025-2034)*

Although there are differences between our initial Preferred Plan and the Supplement Preferred Plan, much of the action we have planned over the long-term horizon is consistent between the two. For example, both plans lay out paths toward achieving 80 percent carbon reduction from 2005 levels by 2030, which include retiring baseload coal units and adding significant variable renewable resource capacity. As we noted in our July 1, 2019 filing, however, the MISO generator interconnection queue process is severely backlogged, and most renewable projects are assigned high interconnection cost estimates, such that most projects continue to withdraw from the queue. This is, in large part, a result of substantial previous renewable buildout that has exhausted existing transmission capacity, even considering vast expansion through multi-value projects in the past. As we transition to a grid mix with even more renewable generation, we will need to add transmission capacity that can support the carbon-free future we are working toward.

The proposed actions we plan on taking during the 2025-2034 period, under the Supplement Preferred Plan, include:

- Adding 3,500 MW of cumulative utility-scale solar between 2025 and 2031.[34]
- Adding 2,250 MW of incremental wind between 2032 and 2034 and repowering existing wind resources when economical.
- Continuing plans to retire Sherco Unit 1 in 2026, and the proposed retirement of King in 2028 and Sherco Unit 3 by 2030.
- Continuing plans to add a natural gas CC at the Sherco site in 2026 and associated natural gas infrastructure, achieving commercial operation prior to ceasing coal operations at Sherco Unit 1.
- Continuing plans to locate more generation in North Dakota.
- Continuing to pursue a Certificate of Need, and a license extension with the NRC, for the Monticello plant.
- Adding approximately 2,600 MW of cumulative firm peaking resources between 2030 and 2034; these additions could be hydrogen-fueled generation, storage or DR, in addition to CTs, depending on cost, reliability, and state policy goals.
- Developing additional regional transmission infrastructure.
- Continuing plans to grow our DR portfolio by approximately 550 MW, to a total portfolio size of approximately 1,500 MW.
- Continuing plans to achieve average annual energy savings of over 780 GWh, through our EE programs.

In addition to these specific plans, we continue to anticipate that, over the next fifteen years, we will explore ways to increase electricity storage on our system, new technologies that can help us achieve 100 percent carbon-free electricity by 2050, and ways we can leverage carbon-free electricity to reach statewide environmental goals—including by electrifying other sectors of the economy, like transportation. We also expect that, beginning with our next Resource Plan, we will explore the economic benefits and necessary actions to extend the Prairie Island nuclear facility operating license.

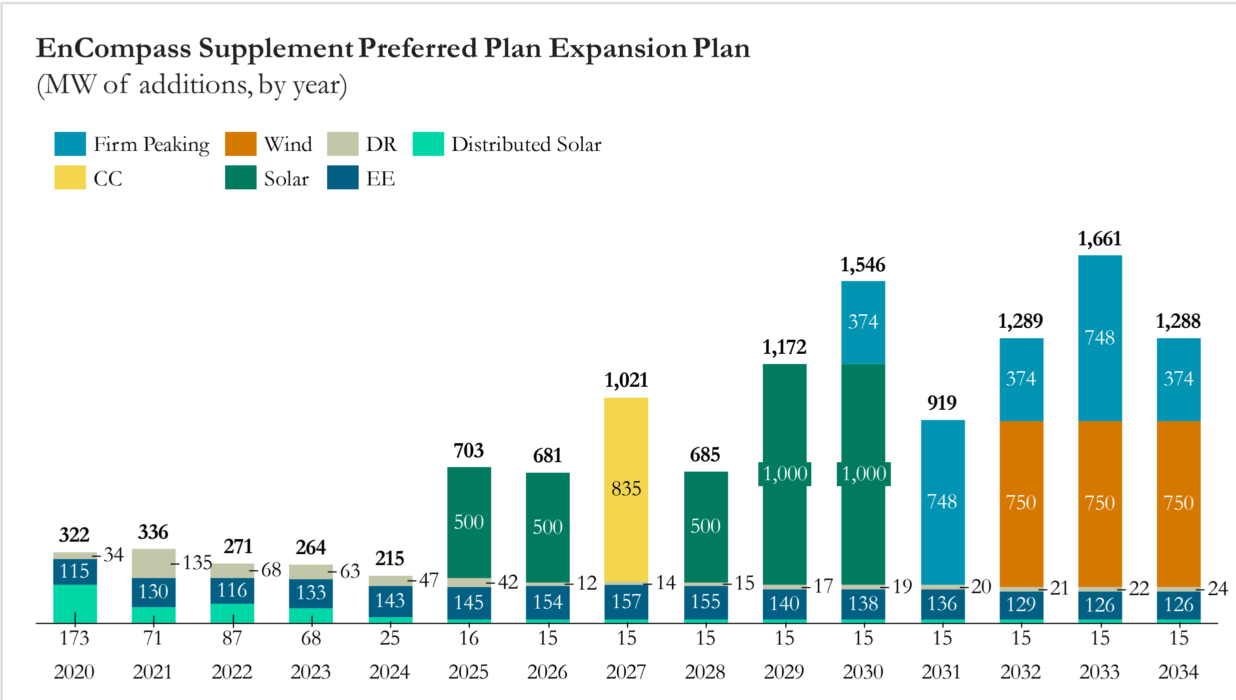
[34] We note that our plan to add these resources is contingent on the existence of sufficient transmission infrastructure and reasonable interconnection costs.

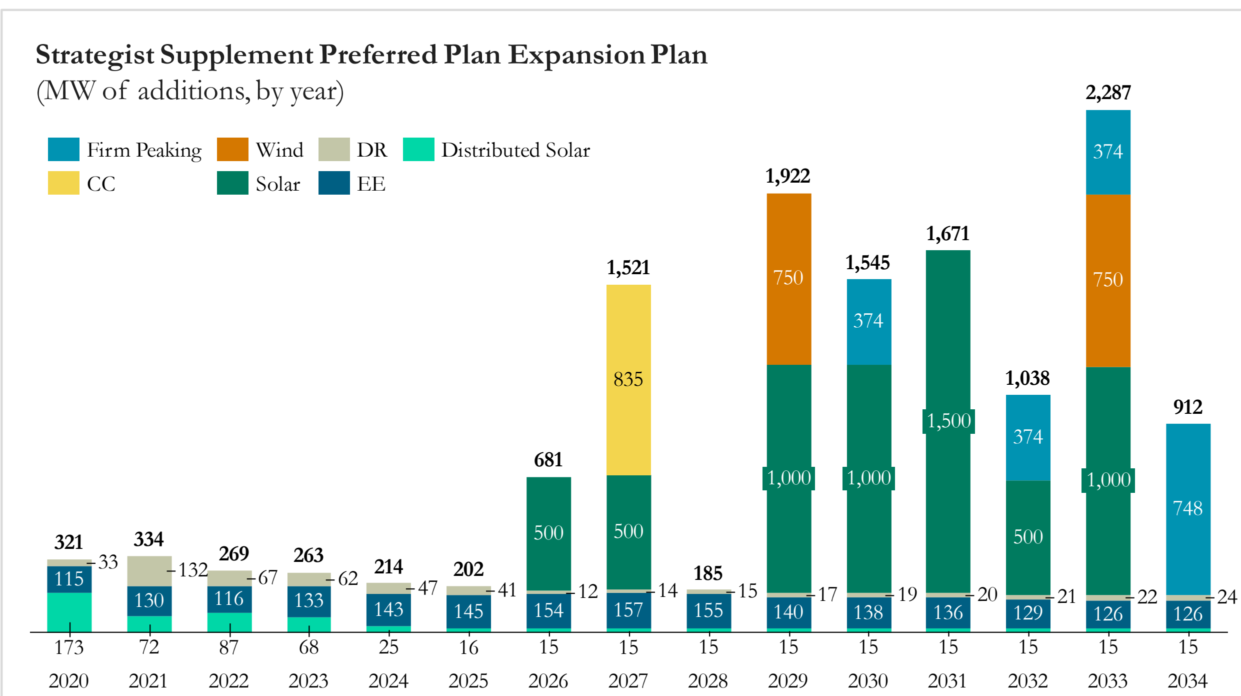
C. Comparison of EnCompass and Strategist Results

As noted above, in preparing this Supplement and choosing our Supplement Preferred Plan, we conducted modeling using both the EnCompass tool we intend to use going forward, and the Strategist tool we have historically used. Because the two tools have different capabilities— primarily that EnCompass is able to model our system on an hourly basis, and Strategist cannot—the modeling results from each tool are, unsurprisingly, different. Because we believe the more granular forecasting capabilities of EnCompass provide us a more accurate view of our future energy and capacity needs, and therefore is a better proxy for our reliability needs, we based our Supplement Preferred Plan on those modeling results.

The updated results from our Strategist modeling, however, provide a valuable comparison, and they directionally confirm the Company's Supplement Preferred Plan. Under both models, our plan for early baseload retirements and extending Monticello provides a clear path for achieving an 80 percent reduction in carbon emissions from 2005 levels by 2030. Relatedly, both show significant savings on a PVSC basis, when considering externality and regulatory CO_2 costs, and additional potential savings depending on future decisions regarding Prairie Island license extension. Additionally, neither model shows a need for resource additions during the Five-Year Action Plan window. Figure 3-3 below shows the amount and timing of the resource additions projected for the Supplement Preferred Plan, from both EnCompass and Strategist.

Figure 3-3: Comparison of EnCompass and Strategist Supplement Preferred Plan Expansion Plans





That is not to say the models entirely align. The specific longer-term projected resource additions differ somewhat between the two, primarily on the amount and mix of renewable and firm peaking resources. Strategist projects additions of approximately 6,000 MW of solar, 1,500 MW of wind, and 1,900 MW of firm peaking resources, whereas EnCompass projects additions of approximately 3,500 MW of solar, 2,250 MW of wind, and 2,600 MW of firm peaking resources. Nonetheless, although these long-term projections are different, they are directionally consistent – both show significant renewable additions and a need for firm peaking resources to support that variable renewable generation.

We believe, therefore, that the results of both our updated Strategist modeling and new EnCompass modeling support the Supplement Preferred Plan. They both support the Five-Year Action Plan outlined above, and the longer-term differences between the two—which will be reevaluated during the next planning cycle—do not undermine the validity of the Plan. Instead, they are the differences one would expect from the notably different modeling methodologies, particularly when considered in light of the uncertainties inherent in longer-term forecasting. We do note that EnCompass is the model that will be used for all subsequent resource planning activities and we believe the results from this model are more robust and better reflect operating realities.

D. Supplement North Dakota Scenario

As discussed in our initial filing, 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. We provided a "North Dakota Plan" in our initial filing, which we have updated consistent with the updates we included in our Supplement Preferred Plan. We refer to this scenario as the "Supplement North Dakota Scenario."

E. Plan Components

While our Supplement 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, we did not impose a constraint in supplemental modeling that required all scenarios to meet our goal. Instead, we allowed the model to optimize resource additions without a constraint on carbon emissions, and we considered the amount of system emissions when selecting our preferred plan. Consistent with this approach in our supplemental modeling, we have not required the Supplement North Dakota Scenario to achieve an 80 percent reduction in carbon emissions by 2030. Consistent with our initially filed

North Dakota Plan, the Supplement North Dakota Scenario differs from the Supplement 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 Supplement Preferred Plan, we included the externality and regulatory costs of CO_2 approved by the Minnesota Public Utilities Commission. The impact of these differences is reflected in the Supplement North Dakota Scenario as shown below:

Table 3-1: Expansion Plan Comparisons
Supplement Preferred Plan – Supplement North Dakota Scenario – Summary of Differences

Supplement 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	0	500	1000	1000	0	0	0	0	3500
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	374	748	374	748	374	2618
DR	34	135	68	63	47	42	12	14	15	17	19	20	21	22	24	553
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126	2041
Wind	0	0	0	0	0	0	0	0	0	0	0	0	750	750	750	2250
Distributed Solar	173	71	87	68	25	16	15	15	15	15	15	15	15	15	15	574

Supplement North Dakota Scenario

	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	0	0	1000	1000	500	0	500	1500	4500
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	374	374	374	0	0	374	748	374	748	0	3366
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	2041
Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Distributed Solar	173	71	87	68	25	16	15	15	15	15	15	15	15	15	15	574

Difference – Supplement North Dakota Scenario Compared to Supplement 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	0	-500	0	0	500	0	500	1500	1000
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	374	374	374	0	0	0	0	0	0	-374	748
DR	-34	-135	-68	-63	-47	-42	-12	-14	-15	-17	-19	-20	-21	-22	-24	-553
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	-750	-750	-750	-2250
Distributed Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

In the modeling for the Supplement North Dakota Scenario, solar additions in 2025 in the Supplement Preferred Plan are delayed to 2029, and firm dispatchable resources are added in 2025 to meet capacity needs. Beyond 2030, solar additions are accelerated, and less wind is added. The Supplement North Dakota Scenario achieves a 73 percent reduction in CO_2 emissions by 2030, while our Supplement Preferred Plan achieves our 80 percent reduction goal. As discussed previously, our Supplement Preferred Plan 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, 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 Supplement North Dakota Scenario. 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.

F. Public Interest Analysis

Based on the additional analysis we conducted in preparing this Supplement, which builds on the analysis underlying our July 1, 2019 filing, we conclude that the Supplement Preferred Plan is in the public interest. We believe it best balances the state's goals of reducing carbon emissions, maintaining reliability, keeping customer costs low, and managing risk 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.[35] 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,

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

- 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.

Our Supplement Preferred Plan is the best option, when considered in light of these criteria and the overall planning landscape.

1. Reliability

When we developed our initial Preferred Plan, we recognized that, as we added increasing variable renewable resources to our generation mix, maintaining reliability would become increasingly complex. To ensure we could meet our reliability obligations in this changing world, we developed a "Reliability Requirement" to include in our Strategist modeling. As Strategist does not have the hourly modeling capability, we needed to ensure the expansion plans developed would meet energy adequacy needs across every hour of the year. This resulted in—among other things—the addition of 1,700 MW of firm peaking resources in the out years of the initial Preferred Plan.

EnCompass hourly chronological modeling results validate our decision to include the Reliability Requirement with the initial Preferred Plan. With EnCompass, we are able to analyze energy adequacy on an hourly basis as a proxy for reliability, which we believe is informative even if it does not specifically analyze reliability as in power flow or voltage-stability analyses. EnCompass selected approximately 2,600 MW of firm, peaking resources[36] in 2030-2034 through its optimization; in other words, we did not force the model to include these resources, but it selected them as part of a least-cost and reliable portfolio.

We also continue to include the planned Sherco CC in the Supplement Preferred Plan to support both the addition of renewable resources in the mid-2020s and our black start plan. Relatedly, as discussed above, our Supplement Preferred Plan includes cost assumptions that reflect an estimate of the amount of investment required to extend the lives of our existing black start generating facilities (approximately 430 MW of accredited peaking capacity), beyond their existing planned retirement dates to 2030. We expect that, depending on the specific resource type, some of the firm peaking

[36] Because these additions do not occur for more than ten years, we are intentionally leaving them technology neutral, recognizing that they could be non-emitting resources like storage or DR.

resources projected to be added between 2030 and 2034 could be available to provide black start services.

2. Impact to Customer Bills

Like our initial Preferred Plan, our Supplement Preferred Plan achieves significant carbon reduction and maintains reliability while keeping average residential customer bills well below the national average, and at a rate of growth below inflation and nearly a full percentage point below the national average growth rate over the planning period. Additionally, by taking limited steps in the next five years, we are preserving flexibility to achieve our carbon reduction goals through the most cost-effective means available in the future. Therefore, we continue to believe our Supplement Preferred Plan is designed to keep rates as low as practicable.

3. Environmental Effects

Our Supplement Preferred Plan continues to chart the path for the Company achieving a completely carbon-free resource mix by 2050, including the relatively near-term steps to achieve carbon emissions reductions of 80 percent below 2005 levels by 2030. We continue to propose closing all of our remaining coal units by 2030 and operating the Monticello nuclear generating plant through 2040. Additionally, the Supplement Preferred Plan projects even more renewable additions than the already significant buildout included in our initial Preferred Plan, as well as continues to pursue ambitious load reduction resulting from DR and EE achievements. All of these actions will ensure we achieve the Company's and state's environmental goals.

4. Socioeconomic Impacts

As noted in our initial filing, the Center for Energy and Environment (CEE) conducted a Host Community Impact Study examining the impacts of the large baseload generation plants in Minnesota on the host communities. That study is discussed in Attachment E of this Supplement.

As we move forward with our carbon reduction goals, we are cognizant that phasing out some of our legacy generation 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. We are dedicated to working with our employees, communities, and stakeholders to manage community impacts throughout our clean energy transition. Our baseload generation plants are prominent places of employment and contributors to the property tax base in the host communities. This is why we make efforts to spur economic development in locations where our current units will eventually be phased out.

In addition to the 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 we have provided various services to enable impacted employees to apply for jobs within Xcel Energy--- these services included résumé writing services, support for interview practice, job training, and job shadowing opportunities. Through natural attrition and job re-locations, we have been able to successfully "re-home" nearly all impacted employees from plant closures and conversions to date. Our plans for ensuring a just and equitable workforce transition are discussed further in Attachment C of this Supplement.

Finally, we acknowledge that the COVID-19 pandemic has made this a particularly challenging time for many people throughout Minnesota and our service territory. In response to the Commission's request, in Docket No. E,G999/CI-20-492, the Company filed a Report laying out a number of proposed investments the Company could make to assist in Minnesota's economic recovery. These investments could create approximately 3,000 new jobs, in addition to the approximately 2,000 jobs created by the renewable, transmission, and advanced grid projects that are currently underway or will be soon. To the extent applicable, we have discussed those proposed and planned projects in this Supplement.

5. Flexibility to Respond to Change and Limiting Risks

Like the initial Preferred Plan, a key aspect of the Supplement Preferred Plan is our ability to maintain optionality and defer significant capacity additions within the Five-Year Action Plan window. We are continuing to defer a decision on extending the life of Prairie Island. Similarly, although we show a need for firm peaking capacity resources from 2030 to 2034, we are not committing to a particular technology or beginning projects in the near term. This allows us to consider options beyond natural gas units, depending on what technologies are sufficiently developed and economically viable in the future. Prioritizing flexibility additionally ensures that we make resource decisions when we have the most complete information on both our system's future needs and different resources' capabilities to meet those needs. Finally, by developing the Supplement Preferred Plan using hourly modeling capability in Encompass – validated by Strategist, which we have relied on for years –

we are ensuring that our Plan limits potential reliability risks as we retire coal-fired baseload units and integrate vast amounts of incremental renewable resources

G. Conclusion

The Supplement Preferred Plan we propose in this Supplement builds upon the strong base of our initial Preferred Plan and remains largely consistent with that plan. The Supplement Preferred Plan continues to eliminate coal and adds even more renewables than the already ambitious initial Preferred Plan, all while keeping bills low for our customers. It also preserves flexibility in how we achieve our carbon reduction goals, deferring important decisions on our nuclear fleet and capacity additions for the future, when they can be re-evaluated with the latest data on our system needs and technology capabilities available at that time. Finally, the updated modeling we used to inform the Supplement Preferred Plan ensures that our plan will maintain reliability at all hours of the year. For all these reasons, and those discussed elsewhere in this filing, we believe the Supplement Preferred Plan is in the public interest and should be approved.

I. MINIMUM SYSTEM NEEDS

Our resource planning process focuses on achieving deep carbon reductions while serving our Upper Midwest customers reliably and affordably. The Minimum System Needs chapter of our July 2019 Resource Plan described how we arrived at the minimum amount of resources our system will need through the planning period to serve our customers.

Our approach to identifying the NSP System's minimum system needs is largely unchanged from our initial filing; however, we have updated certain inputs. In this section, we provide an overview of these changes and provide an updated net resource surplus/deficit view, as well as a summary of Reference Case results. Together these results form the basis of our Supplement Preferred Plan modeling and selection.

Key updates to our minimum system needs assumptions include:

- Corporate load and energy demand forecasts are updated to fall 2019 vintage;
- MISO Resource Adequacy (RA) and planning reserve margins are updated to 2019 guidance, including forward-looking guidance from MISO's Transmission Expansion Planning (MTEP) process;
- Removed the Reliability Requirement as an *ex ante* input, instead allowing modeling software to select resources that ensure reliability, according to identified system needs; and
- Baseline resources now include only existing and authorized additions of resources as of January 2020.

We describe our approach and inputs used to identify minimum system needs further below.

A. Determining 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. We start with an internally developed customer needs forecast, which is derived from customer demand and energy forecasts and adjustments for the effects of energy efficiency resources (EE), distributed energy resources (DER), and electric vehicle (EV) adoption. To this, we add a reserve margin that is prescribed by MISO. We then subtract the energy resources we already have, or expect to have, on our system, in order to determine our net surplus or need.

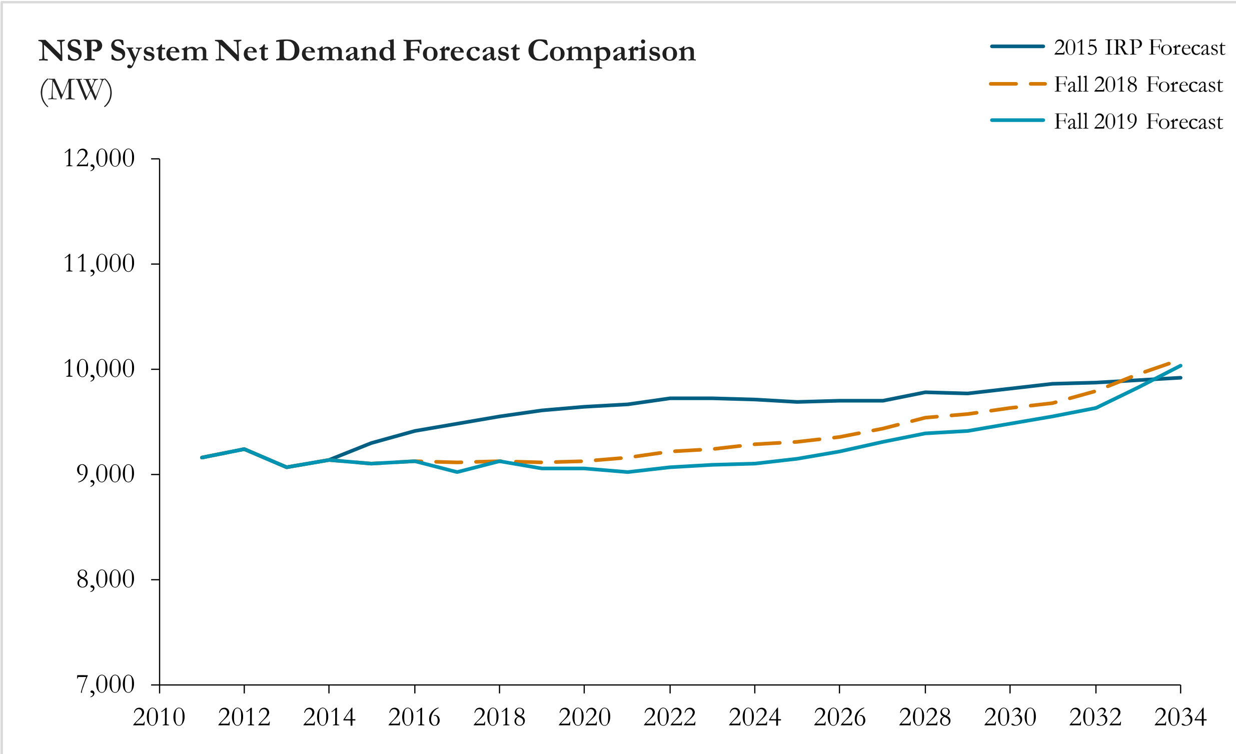
Forecasting our customers' energy needs starts with a peak-hour demand forecast (in MW) and a forecast of our customers' total energy needs (in MWh) for each year of the planning period. We updated the customer needs forecast for this Supplement as discussed below.

1. *Corporate Forecast for Peak Demand Requirements*

Our Load Forecasting team uses econometric analysis and historical actual coincident net peak demand data to determine forecasted system demand, which forms the basis of our capacity requirements for each planning year. From these corporate forecasts, we make adjustments that add back in the effect of anticipated future EE achievements and distributed solar generation, so that we can model EE and distributed solar as competing with supply-side resources in the modeling process. This was a change we first implemented with our July 2019 initial Resource Plan filing and is further discussed below.

The peak corporate demand forecast for this Supplement shows relatively slow load growth, with an average annual growth rate of 0.7 percent, after accounting for reductions to demand from future EE achievements. Figure I-1 below shows the updated corporate net load forecast – called "Fall 2019 Forecast" in the Figure – in relation to the forecast from our initial Resource Plan (Fall 2018 Forecast) and our previous Resource Plan. In general, we expect load to be slightly lower than the forecast used in our initial filing, due to several factors. Some factors reducing the demand outlook include weather-driven near-term energy demand declines, additional anticipated EE savings, and the removal of certain anticipated commercial and industrial load where customers' plans had changed since our fall 2018 forecast. In the out years of the forecast, however, we anticipate more rapid growth as a result of EV adoption. We provide additional discussion addressing these changes in Attachment A, Section II: Load Forecast and III: DER Forecasts.

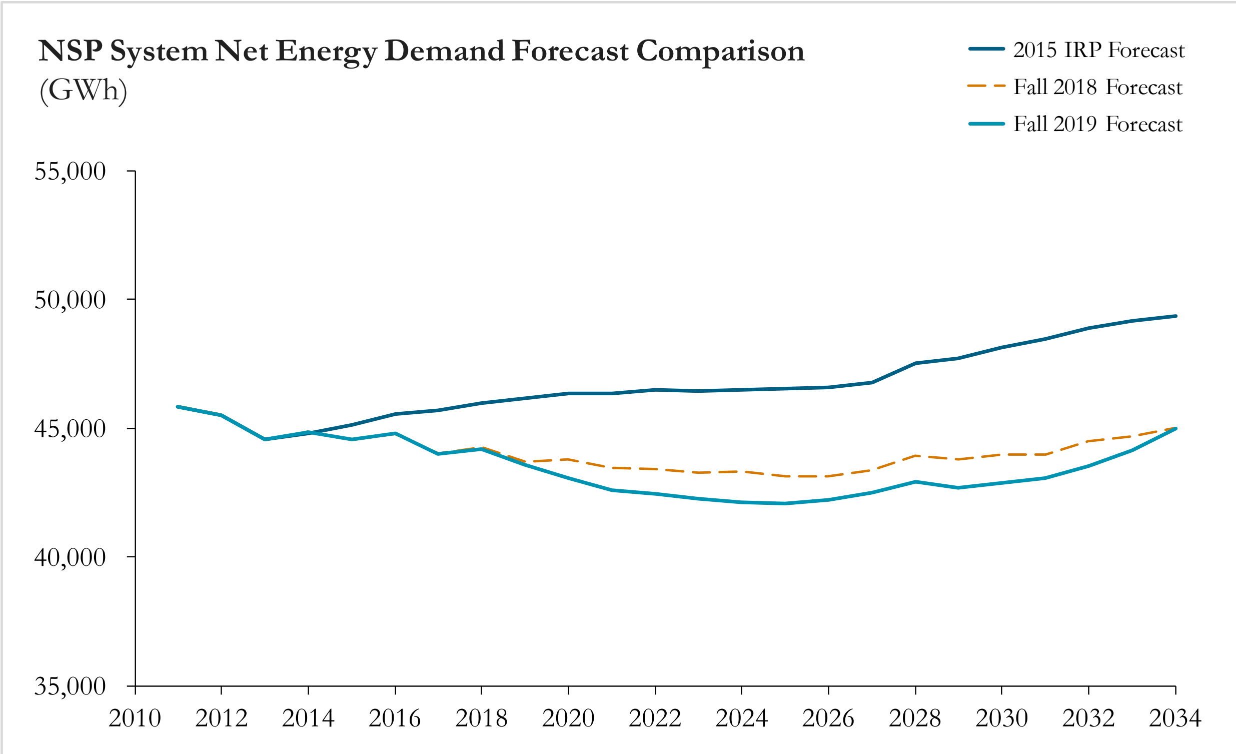
Figure I-1: Corporate Forecast of Peak Load by Vintage



2. *Corporate Forecast for Energy Requirements*

In addition to forecasting peak demand, we also forecast our customers' energy requirements. The energy forecast underlying this Supplement indicates that we expect net energy requirements to be relatively flat, with approximately 0.2 percent growth over the full 2020-2034 planning period. Figure I-2 below portrays our net energy demand for this Supplement, as compared to the forecast in our initial filing and our previous Resource Plan. As discussed above, changes from our Fall 2018 to Fall 2019 forecast vintages are attributable to changes in customer consumption and future plans, additional savings from energy efficiency measures and anticipated EV adoption.

Figure I-2: Corporate Forecasted Net Energy Requirements by Vintage



3. Forecast Adjustments for Anticipated Customer Trends

After determining the base peak capacity and energy demand forecasts, we make adjustments to account for the impact of events or trends we reasonably expect to occur in the planning period. The adjustment types and methods have not changed since our initial filing, although we have updated the forecasts for DER and EVs. We also made certain adjustments to overall demand for large customer changes expected in future years. We note that the baseline forecasts used in this Supplement do not reflect potential effects of the COVID-19 pandemic and resulting recession on our energy demand. It is too early to know to what extent energy demand will decline in response or the duration of these effects.

4. Adjustments to Model Certain Load-Modifying Resources as Competing with Supply-Side Resource Options

As noted in our initial filing, this is the first resource planning cycle in which we have treated load-modifying resources – such as energy efficiency, demand response, and distributed generation – as competing with supply-side resources in our modeling process. Previously, we netted out these resources at an assumed level of adoption across the planning period, and our corporate forecasting process continues to use this method to estimate our net energy and load into the future. However, in the initial plan we filed in July 2019, we tested the economic impact of including various "bundles" of EE and DR – in other words, portfolios of EE or DR measures at an assumed average cost – in order to allow these resources to compete with traditional supply-side resources such as large-scale renewables or gas resources. In order to avoid double counting, however, this requires us to adjust our corporate forecast for use in Strategist and EnCompass modeling.

Figure I-3, below, illustrates the adjustment process. We removed the assumed effect of existing and planned demand-side management programs and distributed solar from the corporate forecast, so that we could model the economic effect of the first two EE Bundles separately. In our initial filing we showed that these two EE Bundles were economic relative to a scenario in which no incremental EE measures were pursued, thus for the purposes of this Supplement, we have included them in our baseline modeling. The end result is a net demand and energy forecast for use in the Resource Plan.

Figure I-3: Illustrative Adjustments to Translate Corporate Forecasts to Resource Plan Model Inputs

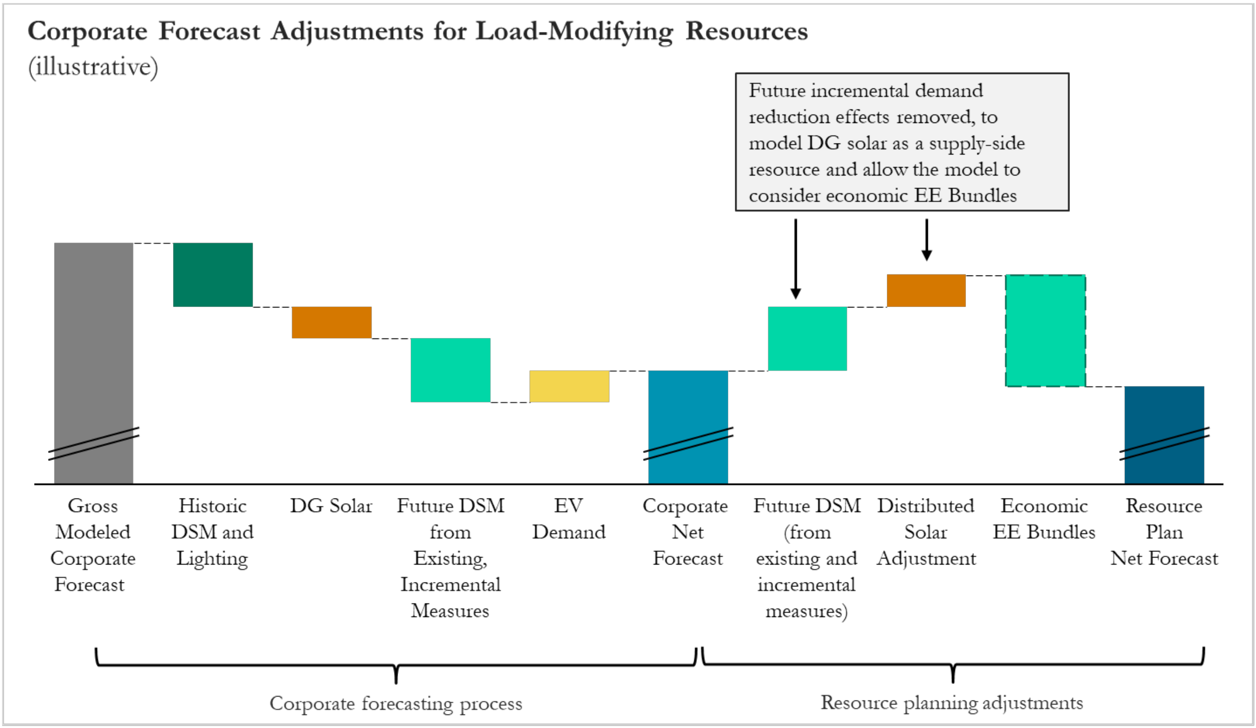


Figure I-4: Net Peak Demand Forecast Adjustments for Resource Plan Modeling[1]

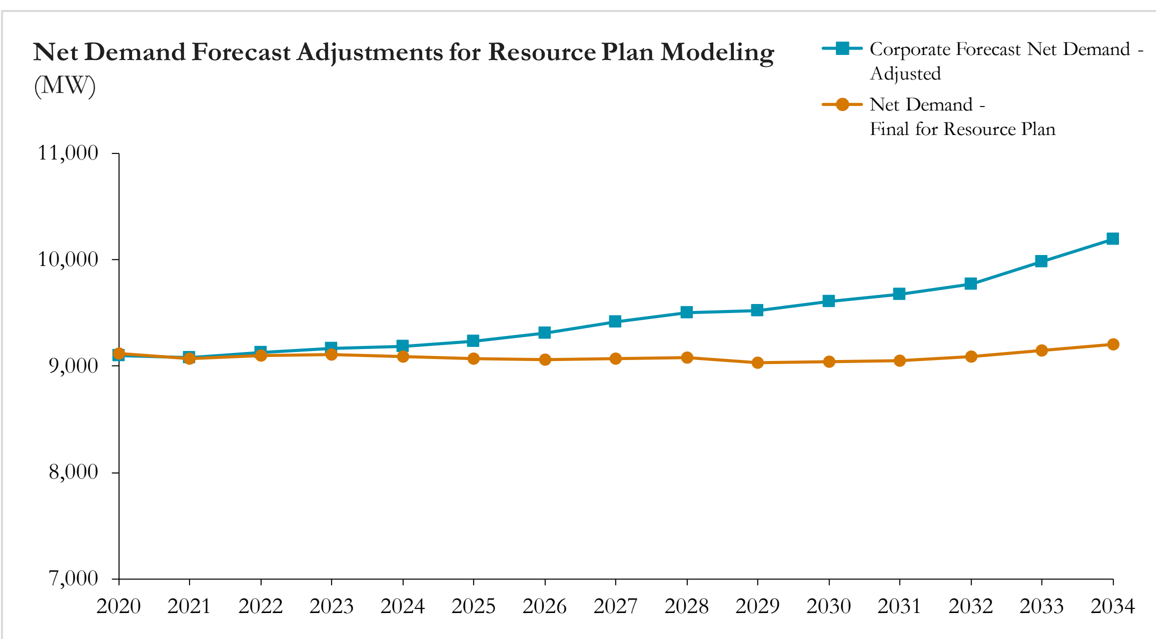
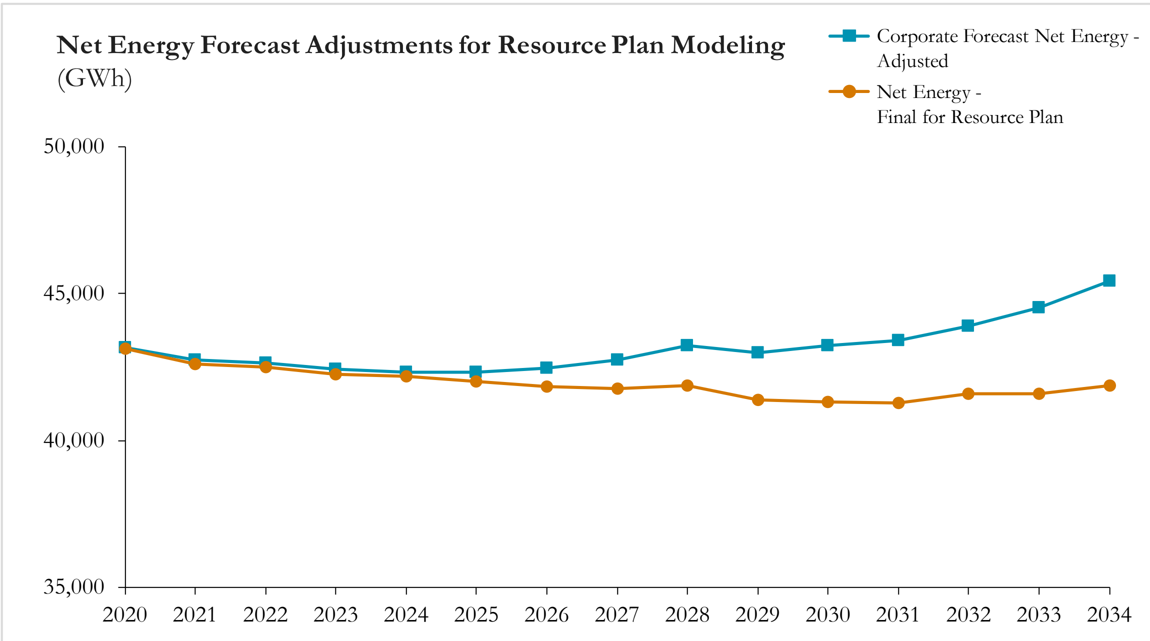


Figure I-5: Net Energy Requirements Forecast Adjustments for Resource Plan Modeling[2]



5. Customer Green Energy Programs

Finally, while they have no effect on total system energy or peak demand requirements, we note the Company offers customer programs that allow customers to specify a preference for renewable energy, and we then correlate that demand to specific resources. Windsource and Renewable*Connect are two programs where we procure renewable energy on behalf of subscribed customers and they pay for these resources directly through Program-specific rates.

In 2003, the Company initiated Windsource, which is a green tariff program that allows customers to subscribe to blocks of wind energy for a premium price. The Company began offering Renewable*Connect (R*C) as a pilot in 2017, in an effort to meet customer demand for a voluntary green tariff that also includes solar resources. In January 2019, we proposed to expand the pilot to a full program and roll

[1] Corporate Forecast Net Demand - Adjusted represents the corporate forecast further adjusted to model distributed solar as a supply-side resource.
[2] Corporate Forecast Net Energy Adjusted represents the base corporate forecast further adjusted to model distributed solar as a supply-side resource.

Windsource customers and resources into the R*C program. The Commission approved our proposal in August 2019.[3]

Customer interest in these programs has been strong, and there are over 2,350 customers on the R*C waiting list.[4] We anticipate a full rollout of the next tranche of R*C to begin in 2022 when our proposed R*C resources come online, and that this tranche will be fully subscribed given the existing customer interest; however, we are not able to confirm this until pricing for the month-to-month and long-term-offer options are finalized and customers sign contracts. We discuss approved and proposed resources aligned to serve Windsource and R*C customers below in Section C. Baseline Resources.

B. 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 (LSEs) like the Company to maintain resources that exceed their level of demand by a specific margin – the planning reserve margin or PRM – to cover potential uncertainty in the availability of resources or level of demand.[5] These RA requirements are fundamental to the resource planning process, informing the level of capacity we need in our portfolio to adequately serve customers' summer peak demand. MISO also continues to explore ways in which it can ensure RA requirements adequately reflect system needs across all hours of the year – through its *Resource Availability and Need* (RAN) and *Renewable Integration Impact Assessment* (RIIA) work – and includes forward-looking capacity accreditation assumptions in its own transmission planning process. Similarly, in an environment with increasing variable resources, the Company must examine resource adequacy in a more nuanced way than it has in the past, to ensure we have the right resource attributes on our system to meet customer needs in every hour of every day.

[3] *See* Docket No. E002/M-19-33. IN THE MATTER OF NORTHERN STATES POWER COMPANY'S D/B/A/ XCEL ENERGY, PETITION TO EXPAND ITS RENEWABLE*CONNECT PROGRAM, *Order Approving Petition with Modifications* (August 12, 2019).
[4] Data as of December 2019. *See* Docket No. E002/M-20-380. ANNUAL COMPLIANCE FILING, TRACKER ACCOUNT REPORT, AND PROPOSED 2021 TARIFF RATES. (March 30, 2020) at 1.
[5] 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.

EnCompass modeling – which evaluates our system's dispatch capabilities on an hourly chronological basis – allows us to conduct a deeper examination in this Supplement, examining the potential for energy and capacity shortfalls on an hourly basis. We discuss our analysis capabilities relative to resource attributes on our system further below and in Attachment A, Section VI: Resource Attributes.

1. *MISO Reserve Margin Requirements Applied to the NSP System*

MISO currently bases its PRM requirements on an annual analysis of the reserve required to avoid loss of load events. Based on the needs indicated in MISO's 2020-2021 Loss of Load Expectation Study (LOLE Study) the Company calculated its effective reserve margin for this Supplement to be 3.46 percent, in comparison to the 2.98 percent applied in our initial filing. This result increases the amount of minimum "buffer" capacity the Company must maintain on the NSP System. We further discuss how we derived this reserve margin below.

For 2020, MISO has indicated an unforced capacity (UCAP) PRM of 8.9 percent,[6] and this requirement remains relatively constant at 8.8-8.9 percent over the full MISO planning period to 2029. We determine the NSP-specific reserve margin based on this information, and the coincident peak demand factor of our own peak load in relation to the MISO peak. Consistent with our initial filing, we continue to estimate a coincident peak demand factor of 95 percent; meaning 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. Considering the MISO PRM and our own coincident peak factor together, our NSP-system effective reserve margin drops from the 8.9 percent MISO-wide PRM to 3.46 percent.

Figure I-6: MISO Planning Reserve Margin Calculation – NSP System Planning Year June 1, 2020 to May 31, 2021

$$(95\, percent\ coincidence\ factor) x\ (1 + 8.9\, percent) - 1 \\ = 3.46\, percent\ effective\ reserve\ margin\ for\ NSP$$

[6] UCAP refers to units' Unforced Capacity Rating, which is a function of the unit's installed capacity (ICAP) 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 2020-2021 Loss of Load Expectation Study Report" at 21. The Study also provides the value in ICAP, which 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.

Applying our effective reserve margin to our annual load forecasts over the planning period determines our overall capacity obligation. We illustrate this calculation for 2020 below.

Table I-1: Capacity Obligation Calculation – 2020 Example

Total Capacity Obligation Component	Value
Forecasted load	9,115 GW
NSP Effective Reserve Margin	x (1+ 3.46%)
NSP Obligation	**= 9,430 GW**

Our updated estimated obligation for all planning period years can be found in the updated Net Resources and Capacity Surplus/Deficit table in Section I.D below.

2. *NSP Resources Capacity Accreditation*

After we determine this MISO obligation level, we consider the types of resources suitable to meet the requirement. MISO's tariff and business practices set forth procedures to enable various types of resources to be used to achieve our RA requirements: (1) capacity resources,[7] (2) load modifying resources,[8] and (3) energy efficiency resources.[9]

Resource accreditation represents a measure of a resource's reliable contribution to System RA needs. A generator's operation, maintenance, and utilization directly impact the portion of nameplate capacity rating currently recognized as an accredited resource. Therefore, for a resource's expected contribution to RA, we use UCAP values instead of ICAP. UCAP is calculated differently for dispatchable resources (e.g., nuclear, natural gas, coal), EE, and DR as compared to non-dispatchable, variable resources (e.g., wind and solar). We discuss how these values are determined in our initial filing.[10]

The RA values for most types of resources have not changed between our initial filing and this Supplement. However, for variable resources – especially wind – MISO

[7] 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.
[8] Behind-the-Meter Generation and DR available during emergencies, which reduces the demand for energy supplies coming from the LSE.
[9] *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.
[10] *See* 2020-2034 Upper Midwest Integrated Resource Plan at Page 53.

modifies its assigned RA values from time to time. In its latest report, MISO assigned wind an Effective Load Carrying Capability (ELCC) of 16.7 percent for wind in Zone 1,[11] which is higher than the 15.6 percent we used in our initial filing. This means that for every 100 MW of installed wind capacity, we can count 16.7 MW toward our RA requirements. MISO has not issued guidance regarding forward-looking wind ELCC values, so we use 16.7 percent across the planning period.

We have also updated our approach to accounting for solar RA values, in response to MISO's recent findings in its *Renewable Integration Impact Assessment* work. This study found that, as solar capacity on the MISO grid increases, it is expected to contribute a diminishing marginal amount of capacity value. This is consistent with other utilities within MISO and other jurisdictions approach modeling solar resource adequacy values.[12] In response, MISO's latest Transmission Expansion Plan analysis uses solar capacity accreditation values that start at the current 50 percent level in 2020-2023 and decline to 30 percent by 2033. We have elected to mirror this assumption in our Supplement modeling, although we have also conducted a sensitivity that holds solar ELCC constant at 50 percent throughout the planning period.

3. Resource Attributes and the Reliability Requirement

In our initial Plan, we discussed the need for a Reliability Requirement, that would maintain sufficient firm dispatchable capacity on our system over the long term, in order to meet customers' energy needs in every hour of every day. This Requirement was derived based on real-world operating conditions: we have, in fact, already encountered days when wind and solar are not available and, but for dispatchable generation on our system, customers' expectations of reliability would not have been met. These were detailed in Appendix J2 of our initial filing. Given the amount of dispatchable capacity that is scheduled to retire from our system in the next 15 years, the volume of new variable, renewable resources we propose to add, and the fact that MISO planning constructs do not yet incorporate the potential effects of vast variable resource additions, we derived a Reliability Requirement as a starting point to ensure that our system is resilient and that our customers experience the system reliability they expect.

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[11] *See Planning Year 2020-2021 Wind & Solar Capacity Credit*. MISO (December 2019), at 4. Available at: https://cdn.misoenergy.org/2020%20Wind%20&%20Solar%20Capacity%20Credit%20Report408144.pdf

[12] For example, DTE Energy, Indianapolis Power & Light and Dominion Virginia – among others – use declining solar ELCC in their resource plan modeling. Further, the California Public Utilities Commission uses an assumption of declining marginal ELCC, both their resource planning and resource adequacy proceedings. Please see Attachment A, Section VI: Resource Attributes for further discussion.

That said, we recognize that, in our initial filing, we were not able to complete robust hourly modeling to analyze more precisely the amount of capacity needed to avoid such periods of unserved energy. This was, in part, because Strategist is not an hourly dispatch model; rather, it provides a view of needed capacity expansion to meet annual requirements according to load duration curve assessments. In order to more fully examine the potential need for firm and dispatchable resources to meet intra- or inter-day net load, we are examining unserved energy potential through our hourly chronological dispatch modeling. In other words, we have not included an *ex ante* Reliability Requirement in our baseload studies. Instead, we have modeled an unconstrained system in Strategist and EnCompass capacity expansion functionality, and then we used EnCompass 8,760-hour chronological modeling to determine our Preferred Plan's reliability risk exposure under low renewable availability conditions. We discuss our findings resulting from EnCompass modeling in Section II. Modeling Framework and Results and Attachment A, Section XI: Supplement Preferred Plan Sensitivities – Reliability Analyses provide additional discussion on how we approach resource attributes in planning in Attachment A, Section VI: Resource Attributes.

C. Baseline Resources

After evaluating customer needs and MISO RA requirements, we then evaluate the baseline of resources we already have to serve customers. This includes all owned, contracted, or otherwise available resources on the system or that have received regulatory approval as of January 31, 2020, through their established expiration dates.[13] We note that this is a departure from our approach in our initial filing, where resources we had proposed and were pending approval were also included. This results in a baseline maximum capacity of over 15,000 MW,[14] approximated below by resource type:

- 4,200 MW of wind, including over 1,500 MW of capacity currently under development
- 1,000 MW of solar (including community and grid-scale solar)
- 950 MW of other renewables (including biomass, landfill gas, and hydroelectric resources)

[13] This could include refer to contract expiration, planned retirement or financial end of life. Black start resources are one exception to this general rule, which is discussed further in this section.
[14] Maximum capacity is approximately the same as ICAP but includes some adjustments for unit availability. We use these max cap values, in combination with MISO-assigned resource adequacy values, in order to derive our UCAP totals for each resource type. These adjusted values help us to determine our net resource surplus/deficit positions, which are shown in Section I.D below.

- 1,740 MW of nuclear
- 4,740 MW of natural gas or oil-fired capacity[15]
- 2,400 MW of coal capacity

We note that the baseline resources included in our Supplement modeling have not substantially changed since our initial filing, with a few exceptions outlined below:

- *Mankato Energy Center*: In our initial filing, the Company's proposal to acquire MEC Units I and II as NSP assets was pending Commission action and the units were included in our modeling as owned assets. Ultimately the Commission denied the request to own MEC as a regulated asset and instead the Company purchased MEC as a merchant facility. The Company has since reached an agreement with Southwest Generation to sell the plant; however, it will continue to serve NSP customers under the prevailing power purchase agreements (PPAs).[16] As such, the current contract expiration dates of 2026 for MEC I and 2037 for MEC II are now reflected in our baseline modeling.
- *Crowned Ridge Wind*: Our initial filing included a 600 MW Crowned Ridge Wind facility that was scheduled to come online by 2020. The project has since been reduced to 400 MW as a result of the Seller encountering prohibitively high transmission interconnection upgrade costs associated with the last phase of the project.[17]
- *Retirement date adjustments*: We received feedback from the Commission that generating unit retirement dates in our modeling – particularly for Sherco Unit 3 – should match the units' current financial-end of-life dates. We have updated several resources' retirement dates based on this feedback.
- *Black start resources*: As we noted in our July 2019 filing, we anticipate that we will need to develop a plan for our black start resources before our next Resource Plan. These units are critical for us to be able to jumpstart the grid "from black" in the event of a widespread outage. Two black start critical units in Minnesota and Wisconsin are scheduled to retire within the planning period, but in reality, we cannot operate a system without viable black start units. While we continue to develop a robust alternatives analysis we included interim placeholder capacity in our modeling, so that we may evaluate a capacity

[15] Not including the planned Sherco CC.
[16] *See* Docket No. E002/AI-19-622 LETTER – MANKATO ENERGY CENTER I AND II AFFILIATED INTEREST REQUEST (April 6, 2020).
[17] *See* Docket No. E002/M-16-777.

expansion portfolio that includes consideration of this future need. We discuss black start resources further in Attachment A, Section VII: Black Start.

We provide a full listing of existing resources included in our modeling in Attachment A, Section V: Resource Options.

We further note that the above totals include some renewable resources that are aligned to customer demand participating in our Windsource and R*C programs.[18] We outline these resources in Table I-2. As described below, there are two additional resources that were not yet approved by the time we locked in the resource list for modeling (as of January 31), and thus are not included in our baseline modeling for this Supplement.[19] One of these projects has since been approved and the other remains pending before the Commission at the time of this filing.

Table I-2: Windsource and Renewable*Connect Program Resources

Name	Type	Size (MW contracted)	Program
Existing Resources *(included in modeling)*			
Various Small Wind	Wind	Approximately 40	Windsource
Moraine II	Wind	50	Windsource
Odell	Wind	No more than 50 (partial output)	Renewable*Connect
North Star	Solar	No more than 25 (partial output)	Renewable*Connect
Recent Resources *(approved after January 31 and not included in modeling)*			
Deuel Harvest North	Wind	100	Renewable*Connect
Pending Resources *(proposed but not yet approved)*			
Elk Creek	Solar	80	Renewable*Connect

The Company files regular status updates on the R*C and Windsource programs, which include more discussion on program demand and resources. Please refer to *Annual Compliance Filing, Tracker Account Report, and Proposed 2021 Tariff Rates* (Docket No. E002/M-20-380) for R*C, and *Compliance Report and Semi-Annual Tracker Account*

[18] Note that the resources currently aligned to Windsource customers will continue to serve customers when the Windsource program sunsets and subscribers and resources are rolled into the R*C program.
[19] *See* Docket No. E002/M-19-33. IN THE MATTER OF NORTHERN STATES POWER COMPANY'S D/B/A/ XCEL ENERGY, PETITION TO EXPAND ITS RENEWABLE*CONNECT PROGRAM, *Order Approving Petition with Modifications* (August 12, 2019) at Order Point 3.

Report, Voluntary Renewable Energy Rider (Windsource) (Docket No. E002/M-01-1479) for additional details.

D. Net Resources and Capacity Surplus/Deficit

After assessing our anticipated load and MISO requirements, we compare our system-wide obligations to the resources we already have – existing or approved – on our system. As we have discussed, we expect our near-term customer load to decline, given increased EE and DR opportunities, but in the longer-term beneficial electrification growth is expected to offset some of these declines. Further, MISO has increased its PRM requirement since our initial filing. As shown below, given current unit retirement dates and existing or approved resources only, we would anticipate a net capacity surplus as measured by the MISO RA requirements through 2025, and a deficit thereafter. Our Reference Case and various baseload scenario capacity expansion plan modeling assesses potential combinations of resources that address this overall capacity deficit.

Table I-3: 2020-2034 System Net Accredited Capacity Surplus/Deficit Prior to Expansion Planning (MW, resource values measured in terms of UCAP)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
System needs															
Forecasted gross load	10,502	10,563	10,635	10,711	10,780	10,842	10,911	10,982	11,053	11,119	11,184	11,253	11,324	11,391	11,452
EV Forecast	8	12	17	25	35	44	53	65	79	99	126	163	214	273	336
Forecasted EE[20] (reduction to load)	(1,395)	(1,508)	(1,550)	(1,625)	(1,723)	(1,817)	(1,907)	(1,975)	(2,052)	(2,189)	(2,269)	(2,367)	(2,448)	(2,521)	(2,583)
Forecasted net load	9,115	9,067	9,101	9,111	9,092	9,068	9,057	9,072	9,080	9,029	9,041	9,049	9,090	9,143	9,205
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Load	8,659	8,614	8,646	8,655	8,638	8,615	8,604	8,618	8,626	8,578	8,589	8,597	8,636	8,686	8,745
MISO PRM	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%
NSP Obligation	9,430	9,380	9,416	9,426	9,406	9,382	9,370	9,385	9,393	9,341	9,354	9,362	9,404	9,459	9,523
Existing and approved resources (UCAP)															
Load Management *(existing)*	1,012	1,027	1,041	1,055	1,066	1,072	1,077	1,078	1,077	1,071	1,059	1,048	1,037	1,026	1,016
Load Management *(potential study)*	33	165	232	294	341	382	394	407	423	440	458	478	499	521	545
Coal	2,295	2,295	2,295	2,295	1,647	1,647	1,647	994	994	994	994	994	994	994	994
Nuclear	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,019	1,019	1,019	498	0
Natural Gas/Oil	3,858	3,858	3,858	3,858	3,713	3,403	3,112	2,831	2,831	2,831	2,831	2,288	2,012	2,012	2,012
Sherco CC	0	0	0	0	0	0	0	728	728	728	728	728	728	728	728
Biomass/RDF	110	110	110	86	86	61	61	61	29	29	29	19	19	19	19
Hydro	881	1,001	993	993	993	162	162	162	162	162	162	162	156	152	152
Wind	498	623	672	647	635	631	626	611	605	583	582	566	563	498	479
Grid-scale solar	129	129	128	127	122	116	110	105	99	94	88	83	78	73	72
Solar*Rewards Community Solar	329	357	394	421	409	392	376	359	343	326	309	292	276	259	259
Distributed Solar	37	45	53	60	64	68	71	74	76	78	78	79	78	77	81
Existing Resources	10,824	11,252	11,418	11,478	10,717	9,576	9,278	9,052	9,007	8,976	8,338	7,757	7,459	6,857	6,358
Net Resource (Need)/Surplus	1,394	1,871	2,002	2,052	1,311	195	(92)	(334)	(386)	(365)	(1,016)	(1,605)	(1,945)	(2,602)	(3,166)

E. Reference Case Results

After establishing the net surplus/deficit, we then begin modeling our future capacity expansion portfolios around "baseload scenarios," which test combinations of baseload unit retirement dates. Our Reference Case – or Scenario 1, to which we compare all other scenarios – reflects baseload unit retirement dates as they stand today. Our other baseload scenarios test different combinations of retirement dates to examine whether a different approach may benefit customers by reducing the net present value of costs associated with the resulting portfolio of capacity additions.

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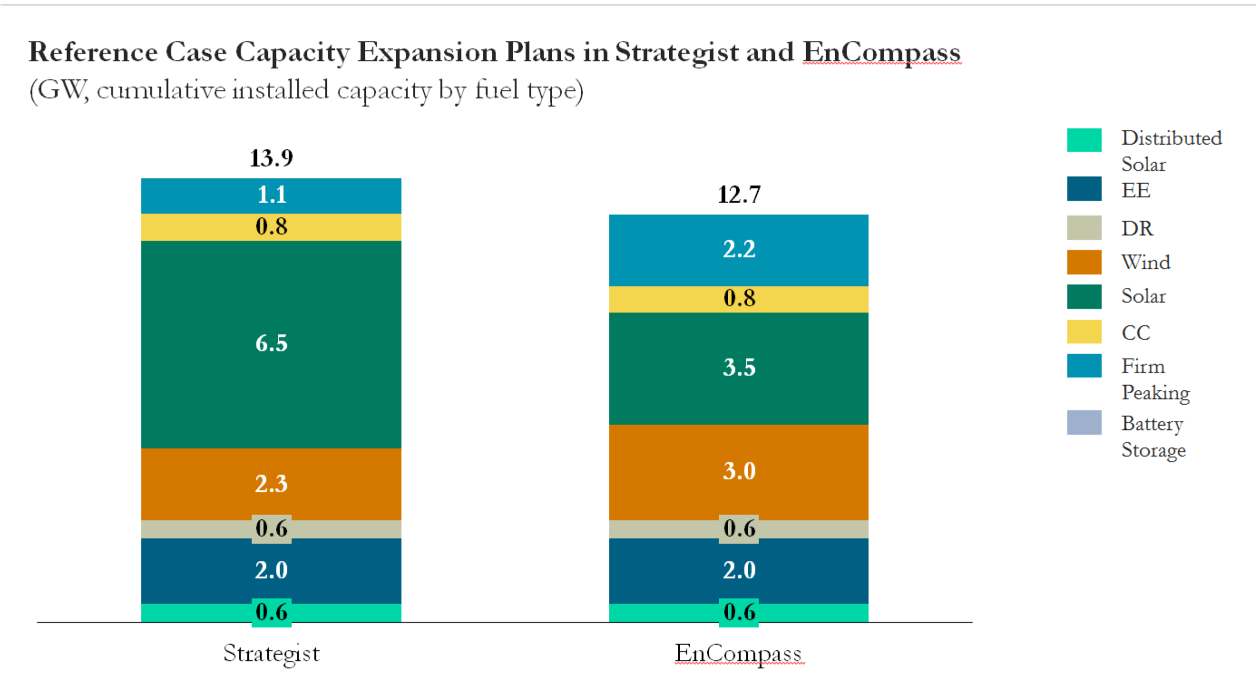
[20] Includes EE savings from historically installed measures, as well as future EE from bundles modeled in this Resource Plan, achieving 2-3% savings levels.

As discussed in this filing, the Company has modeled baseload scenarios both in Strategist – our legacy forecasting tool – as well as the new EnCompass model. Because these models use distinctly different approaches to arrive at capacity expansion plans, they also come to different conclusions regarding optimal future portfolios and energy dispatch. As illustrated in Figure I-7 below, the Strategist Reference Case expansion plan includes a substantial amount of solar capacity additions whereas the EnCompass model's Reference Case selections reflect less capacity overall and a more balanced portfolio of additions across wind, solar and firm peaking capacity.

Figure I-7: Reference Case Capacity Expansion Plans



Both the Strategist and EnCompass Reference Case capacity expansion plans result in high levels of renewable and carbon-free energy on our system by 2034. Strategist modeling shows the Reference Case achieving 76 percent carbon-free energy by 2034, up from 60 percent in 2020. The EnCompass capacity expansion plans result in the Reference Case achieving 71 percent carbon-free energy by 2034, up from 56 percent modeled in 2020. The 2020 share of carbon-free energy differs as a result of the models' different approaches to system dispatch.

Figure I-8: Reference Case Energy Mix in 2020 and 2034, from Strategist

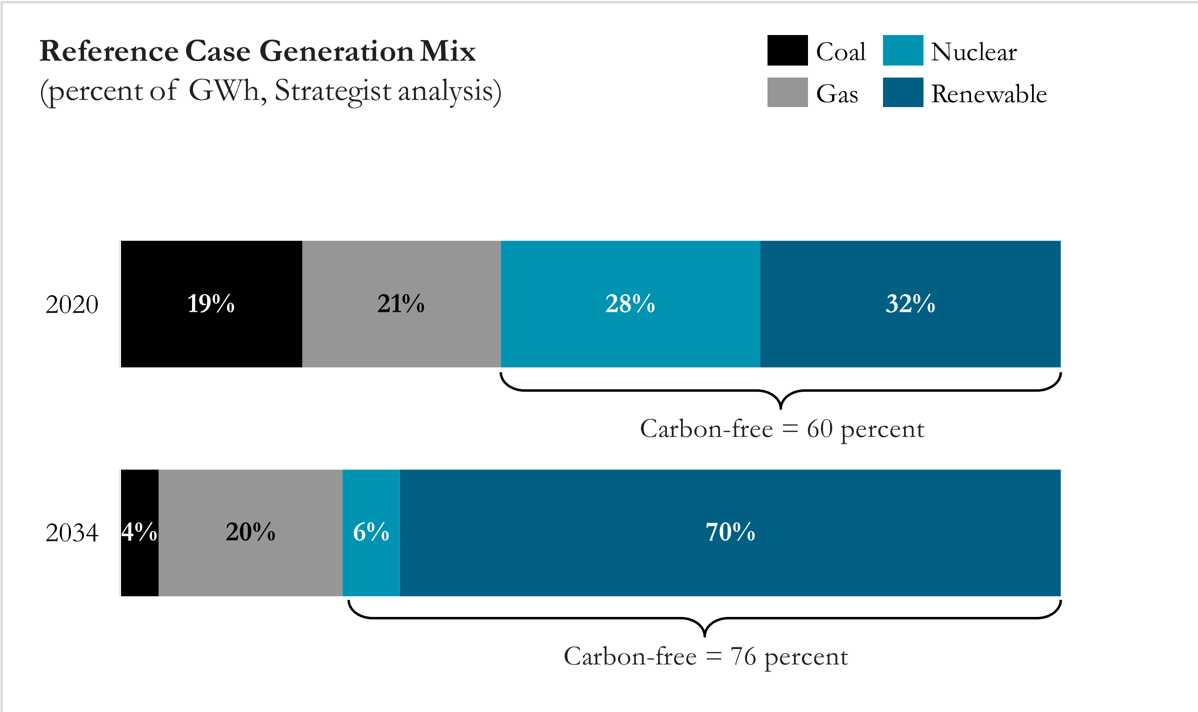
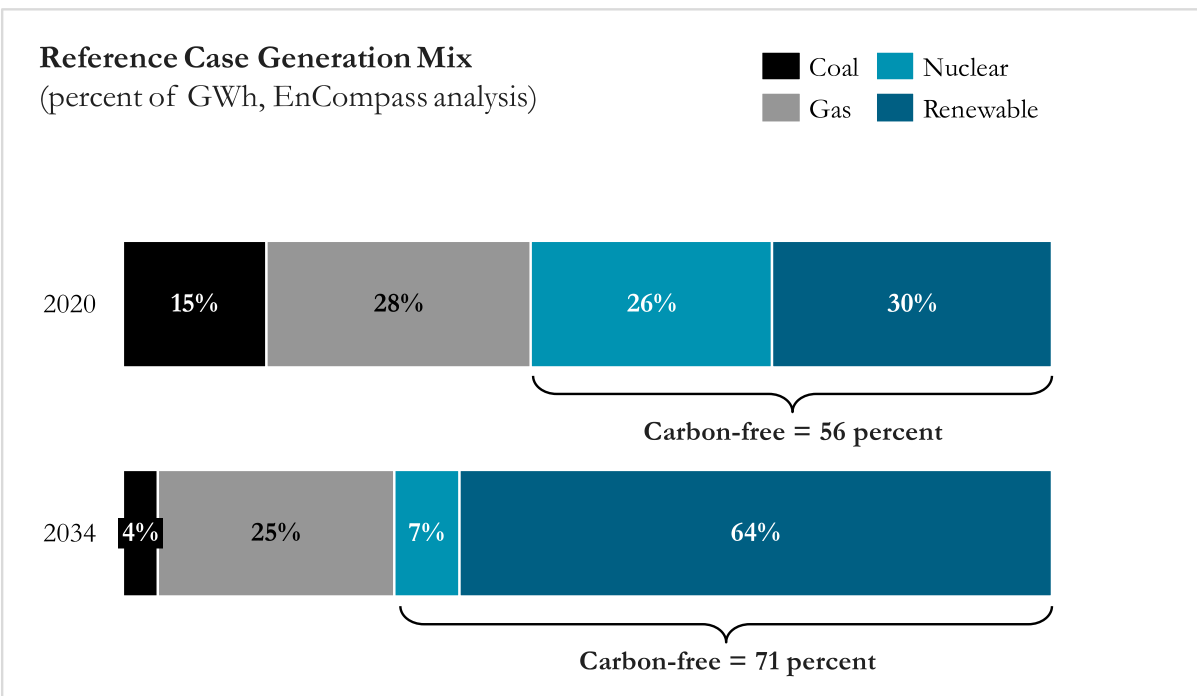


Figure I-9: Reference Case Energy Mix in 2020 and 2034, from EnCompass



II. LOAD FORECAST

This Section discusses the methodology we used in conjunction with this Resource Plan to forecast customer need. The underlying econometric models and statistical techniques used in our initial Plan in July 2019 have not changed, so we do not address them in detail in this Supplement.[21] Further, we continue to make adjustments in order to appropriately align our corporate load forecasting methods with Resource Plan objectives of modeling demand-side resources in competition with generic supply-side resource options, such that both types of resources are evaluated for inclusion into our Supplement Preferred Plan on an economic basis. This section discusses the outcomes of our energy and demand-side resource forecasting.

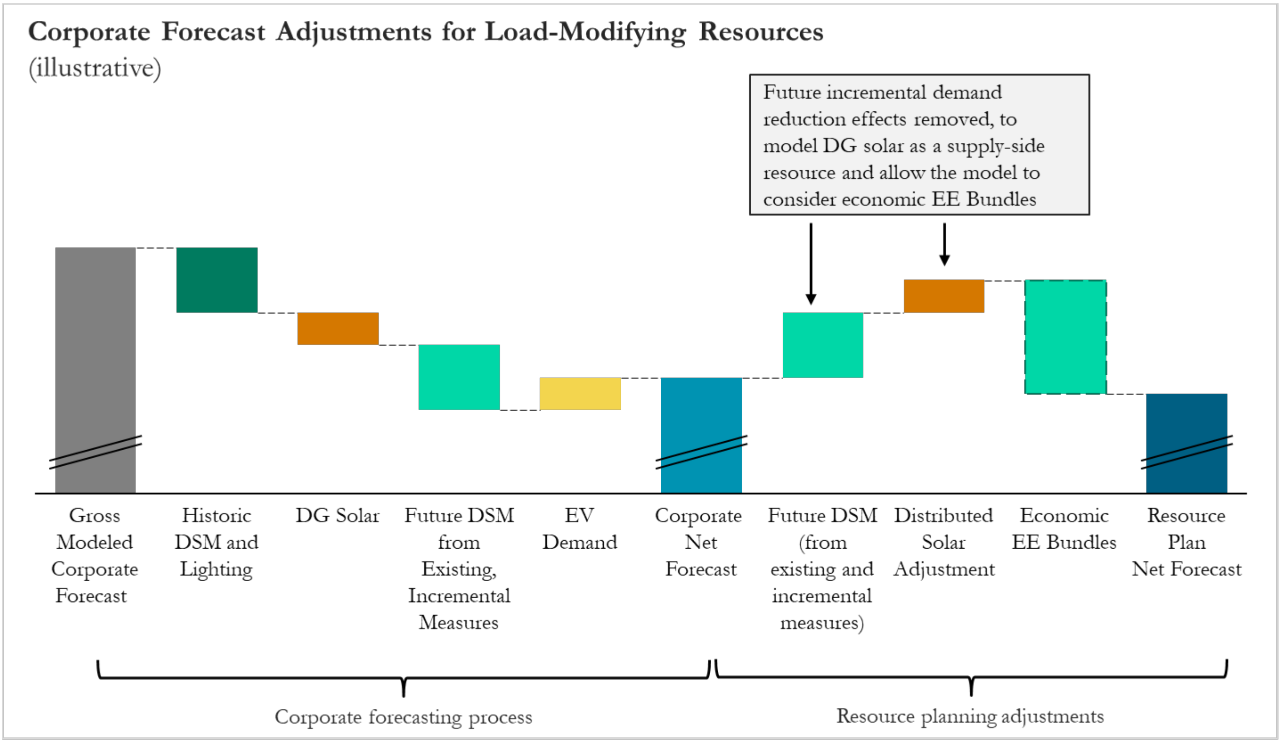
At a high level, the Company relies on econometric models and other statistical techniques to develop the sales forecast. The econometric models relate our historical electric sales to demographic, economic and weather variable data. For example, we use projections of economic activity for our various service areas that are provided by IHS Markit Inc. (formerly IHS Global Insight, Inc.). Based on this and other inputs, 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 then 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 note that the corporate forecasts described in this section are adjusted before they are used in Strategist and EnCompass modeling, so that we can allow the model to evaluate demand-side resources – such as incremental EE and distributed solar (or DG Solar) – against supply-side resources in the Strategist and EnCompass modeling processes. We also test different levels of incremental demand from electric vehicles (EV) in sensitivities, later in the modeling process. The corporate forecast adjustment process for use in resource plan modeling is further illustrated in Figure II-1 below. This section focuses primarily on discussing corporate forecast methodology

[21] Please refer to Appendix F1 of our initial filing for a detailed discussion of load forecasting methodologies.

development, with notes regarding adjustments for use in resource plan modeling where relevant.

Figure II-1: Illustrative Adjustments to Translate Corporate Forecasts to Resource Plan Model Inputs



Finally, we note that the recent COVID-19 pandemic and associated economic slowdown has certainly affected the overall amount and patterns of our customers' energy consumption. We are continuing to monitor these changes; however, it is too soon to attempt to capture the potential long-term effects in the forecasts underlying this Supplement.

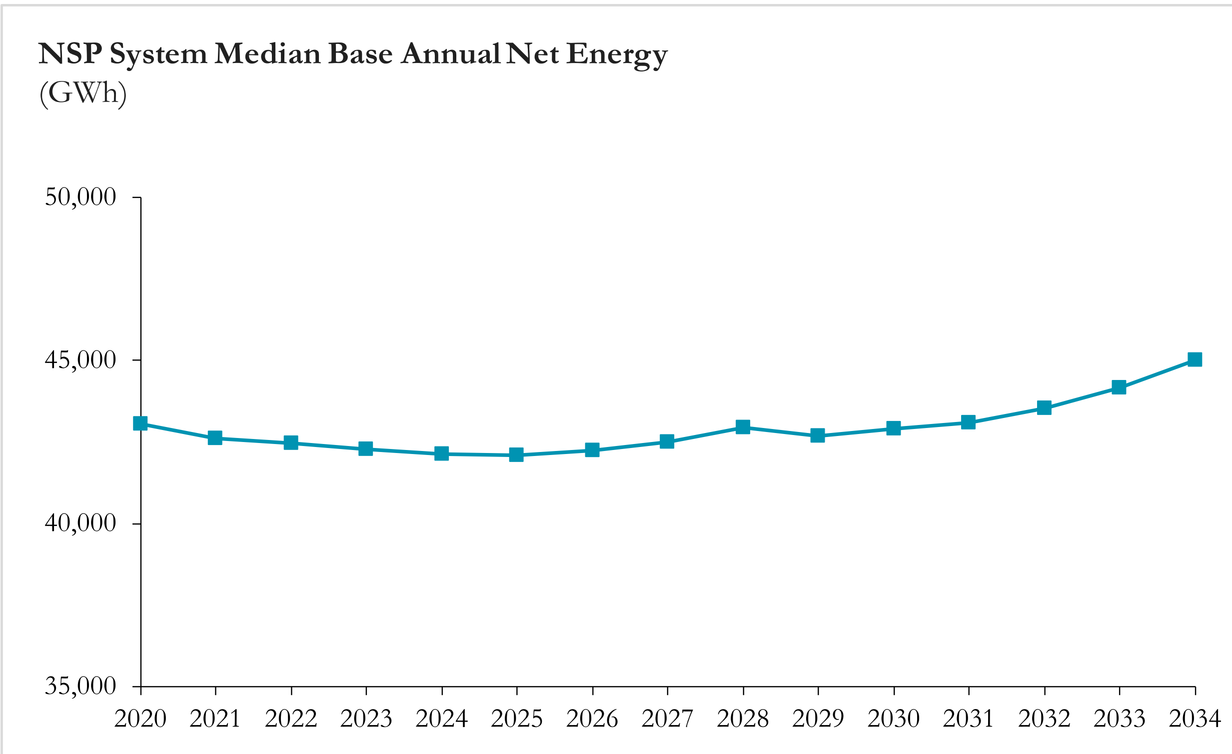
A. Energy Forecast

1. Base Forecast Methodology

Our updated base energy forecast increases at an average annual growth rate of 0.2 percent over the 2020 – 2034 planning period, net of approximately the same amount of energy efficiency (EE) savings levels included in our initial Preferred Plan, as well as updated forecasts for distributed solar energy production, and electric vehicle charging consumption.

Taking these adjustments into account, the base forecasted electric energy requirements are expected to increase at an annual average of 140 gigawatt-hours (GWh), growing from approximately 43,000 GWh in 2020 to 45,000 GWh in 2034. See Figure II-2 below.

Figure II-2: NSP System Total Median Net Energy



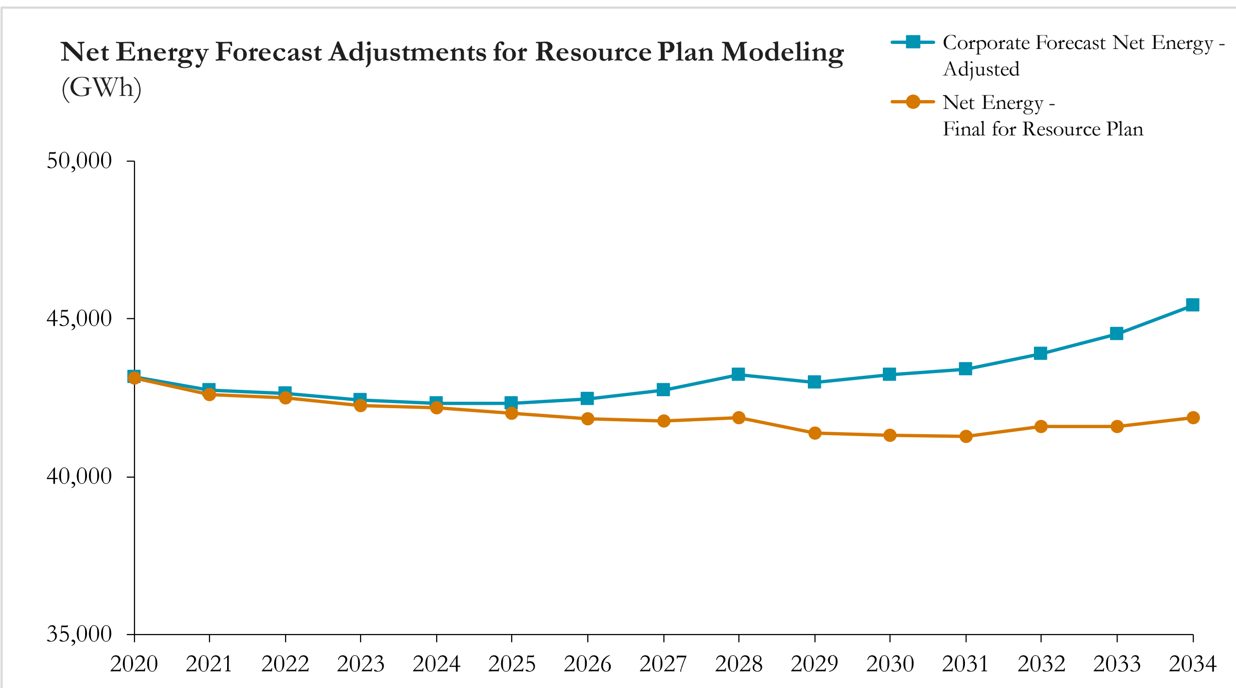
We note that the projected 0.2 percent average annual growth in electric energy requirements is stronger than the actual growth seen over the past few years. After adjusting for unusual weather, electric energy requirements *decreased* at an average annual rate of 0.2 percent from 2014 to 2018.

2. *Modifications for Use in Resource Plan Modeling*

As noted above, we undertook additional steps in the course of resource plan modeling, in order for incremental new 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 new 2020-2034 program year EE achievements. We also disaggregated DG Solar resources, as discussed previously. We then included incremental potential EE savings amounts from the 2020-2034 program years in Strategist and Encompass modeling processes as "Bundles," which compete on an economic basis with supply-side resources. In effect, this allows us to treat projected additions of DG solar and portfolios of new EE measures, at a given average cost, like generic supply-side resources.

Given the first two EE bundles were shown to be economic in our initial modeling (as filed in July 2019), we have included them in our baseline modeling in this Supplement. As a result of these adjustments, the net forecast for Resource Plan modeling declines across the modeling period, as compared to the corporate forecasts, as reflected in Figure II-3 below.

Figure II-3: Net Energy Requirements Forecast Adjustments for Resource Plan Modeling[22]



We discuss the EE Bundle modeling further in Attachment A, Section IV: Modeling Inputs and Assumptions and Attachment A, Section V: Resource Options.

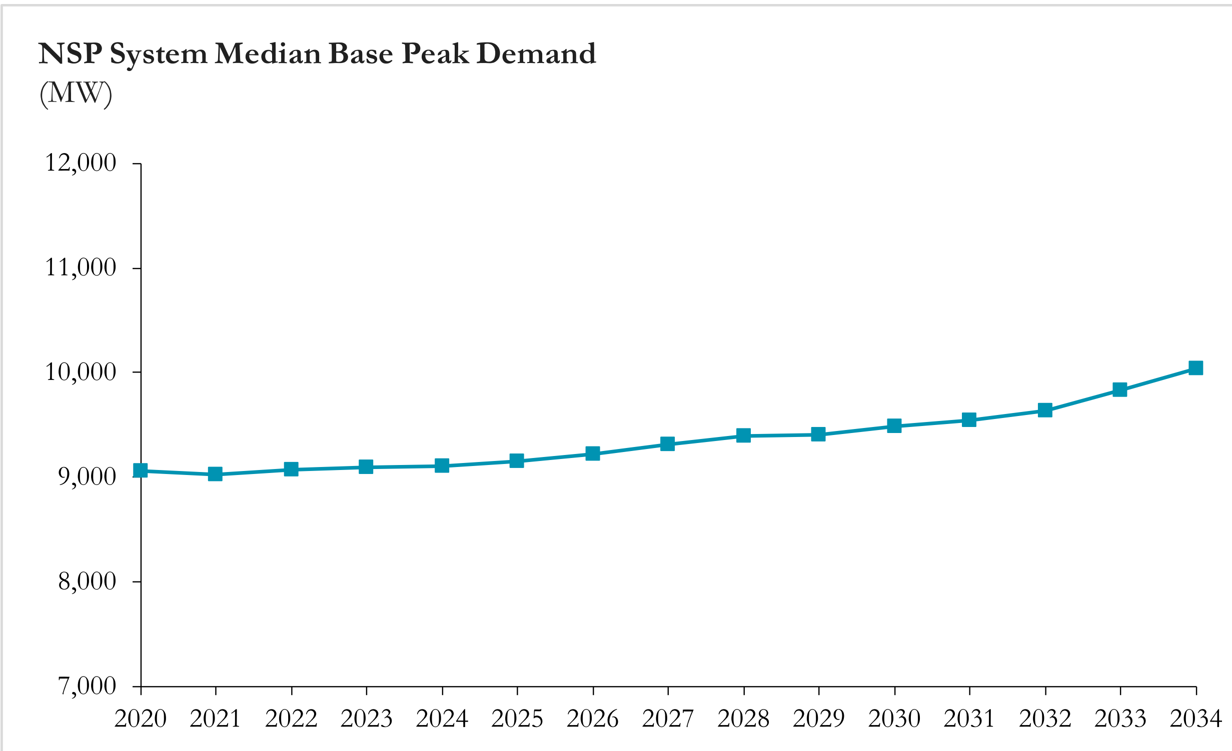
[22] Corporate Forecast Net Energy Adjusted represents the base corporate forecast further adjusted to model distributed solar as a supply-side resource.

B. System Peak Demand Forecast

1. *Base Forecast Methodology*

During the 2020-2034 planning period, the median base peak demand corporate forecast increases at an average annual growth rate of 0.7 percent, when including effects of already assumed EE. As demonstrated in Figure II-4 below, annual peak demand increases at an average of 66 MW each year, starting with just over 9,000 MW in 2020 to just under 10,000 MW in 2034.

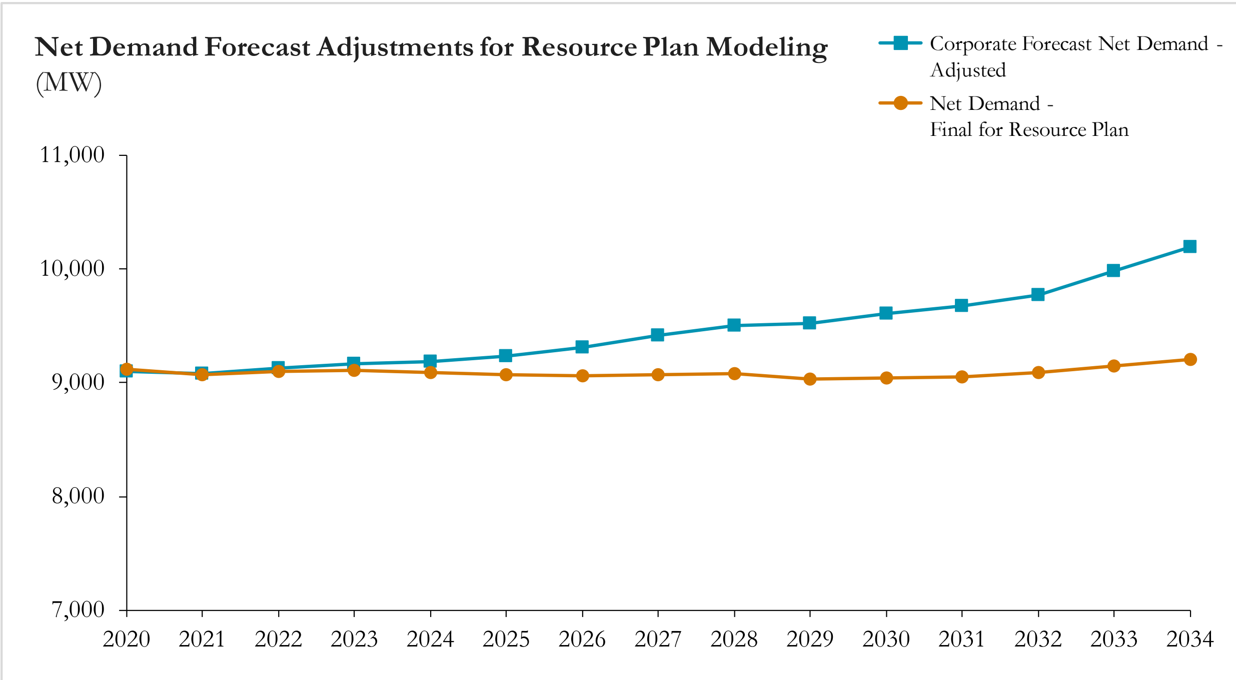
Figure II-4: NSP System Median Base Summer Peak Demand



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 corporate forecast and remove the effects of future incremental 2020-2034 program year EE adjustments, but then include the first two EE bundles in our net forecast for use in Resource Plan modeling. This process enables us to evaluate how EE Bundles can compete with supply-side resources in our modeling. We also make adjustments for DG solar. The net effect of this adjustment reduces forecasted demand relative to the corporate forecasts.

Figure II-5: Net Peak Demand Forecast Adjustments for Resource Plan Modeling[23]



C. Key Demand and Energy Forecast Variables

The balance of this section discusses the energy and peak load forecasting methods, assumptions, analytics, adjustments, etc. to derive the Corporate System Energy Forecast presented above. In general, our approach to modeling energy and capacity demand forecasts is consistent relative to our initial filing, even as some inputs and assumptions have been updated.

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

[23] Corporate Forecast Net Demand - Adjusted represents the corporate forecast further adjusted to model distributed solar as a supply-side resource.

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 IHS Markit Inc.

We forecast an average annual growth rate for total residential customers on our system of 0.6 percent, with the addition of 9,922 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. IHS Markit Inc. 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.

Once the NSP System peak demand forecast is complete, a forecast is developed for the NSP System demand coincident with the 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 uses the NSP System demand coincident to the MISO annual peak demand during the 2020-21 planning year (June 2020 – May 2021).

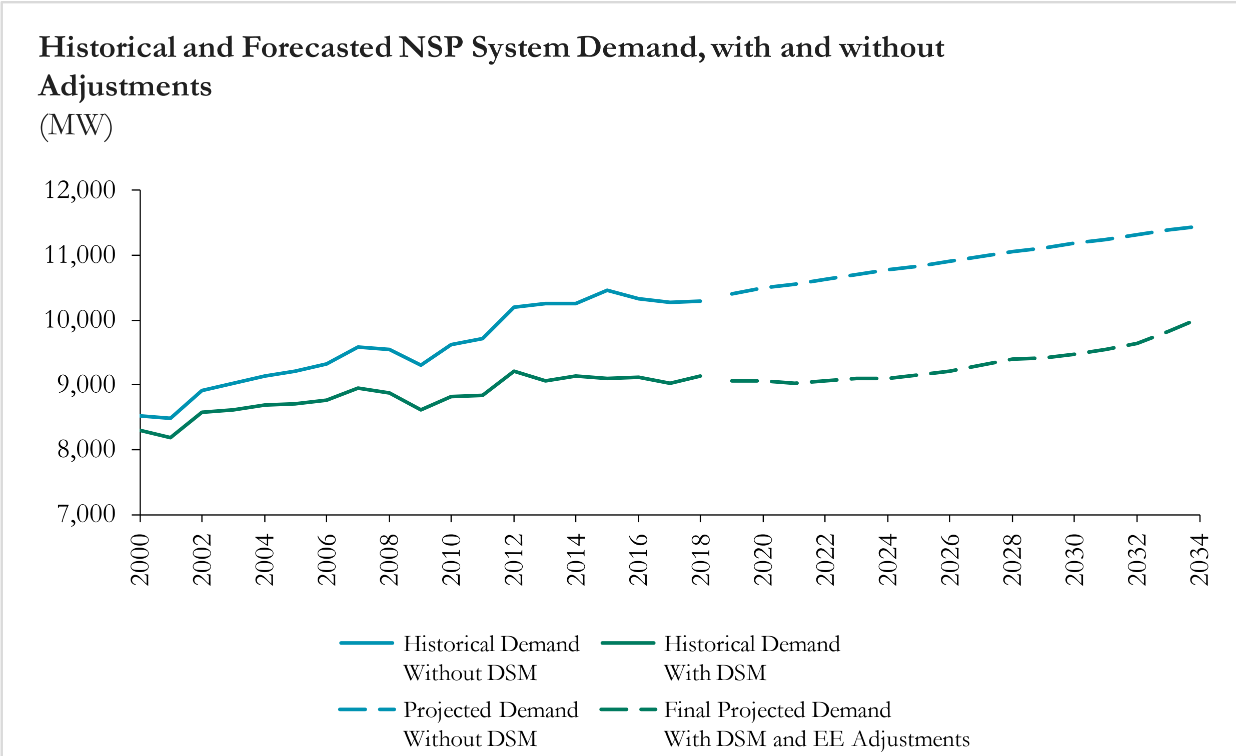
E. Corporate Forecast Adjustments

Our demand and energy forecasts are developed using a number of key forecast variables as described in this section. 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); and
- Adjust the forecast to show the impact of all planned EE in future years (and further adjust the forecast to account for codes and standards changes resulting in decreased sales that are in addition to Company-sponsored EE).

Figure II-6: Illustration of EE Adjustment – NSP System Demand



For the State of South Dakota, the impacts from all conservation program installations prior to 2019 are assumed embedded in the historical demand and energy data at a rate equal to the annual program installations from 2014 through 2018. 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 2019 goal as approved in the 2017 South Dakota DSM Status Report and 2019 DSM Plan filing (Docket No. EL18-023).

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; and
- 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

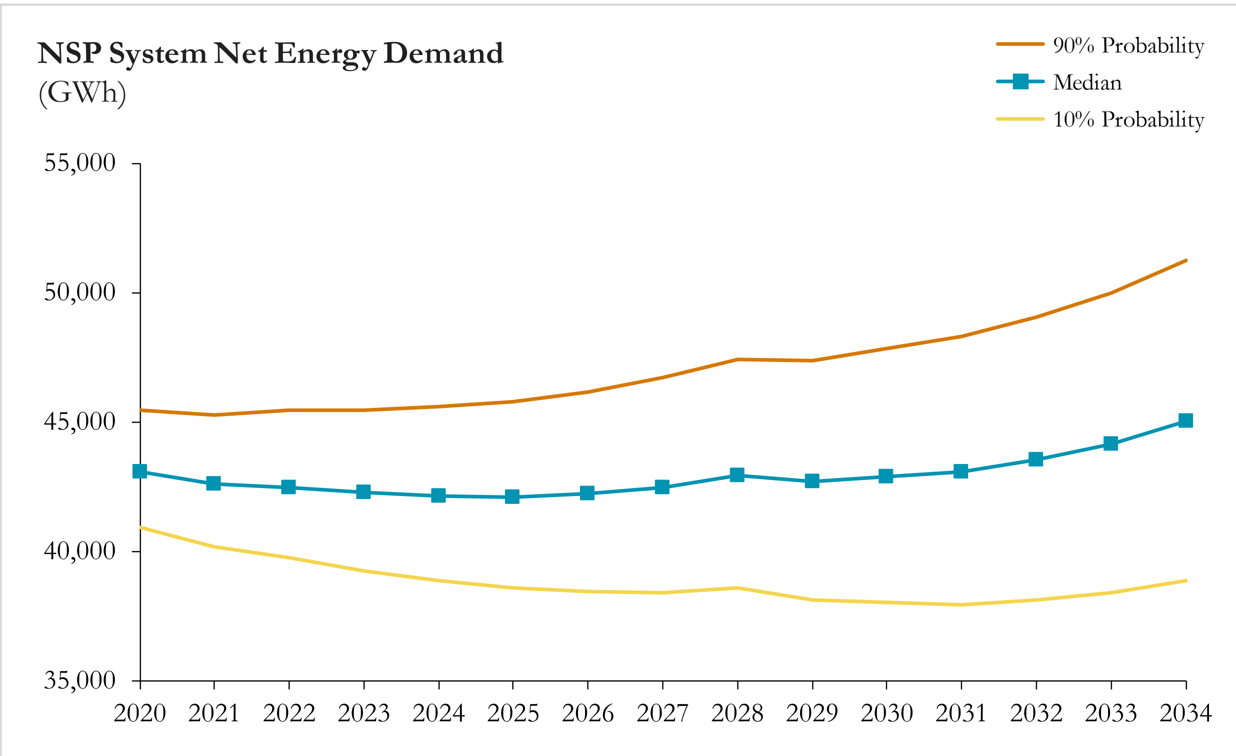
As with any forecast, our forecasts of energy requirements and peak demand depend on other forecasts of key variables. Changes in these variables will affect our forecasts. For instance, if the number of households in our service territory is lower than IHS Markit Inc. has predicted, electric consumption 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 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.

The probability distributions developed for this forecast yielded a 90 percent probability that the net energy will be less than 51,261,533 MWh in 2034 – or alternatively, there is a 10 percent probability that the net energy will be less than 38,887,528 MWh. See Figure II-7 below.

Figure II-7: NSP System Total Net Energy



Figures II-8 and II-9 below show the higher and lower variations of the 2020 to 2034 long-range forecasts of base and net summer peak demand. [24]

[24] Where net summer peak demand includes adjustments form the base forecast to account for interruptible load.

Figure II-8: NSP System Total Base Summer Peak Demand

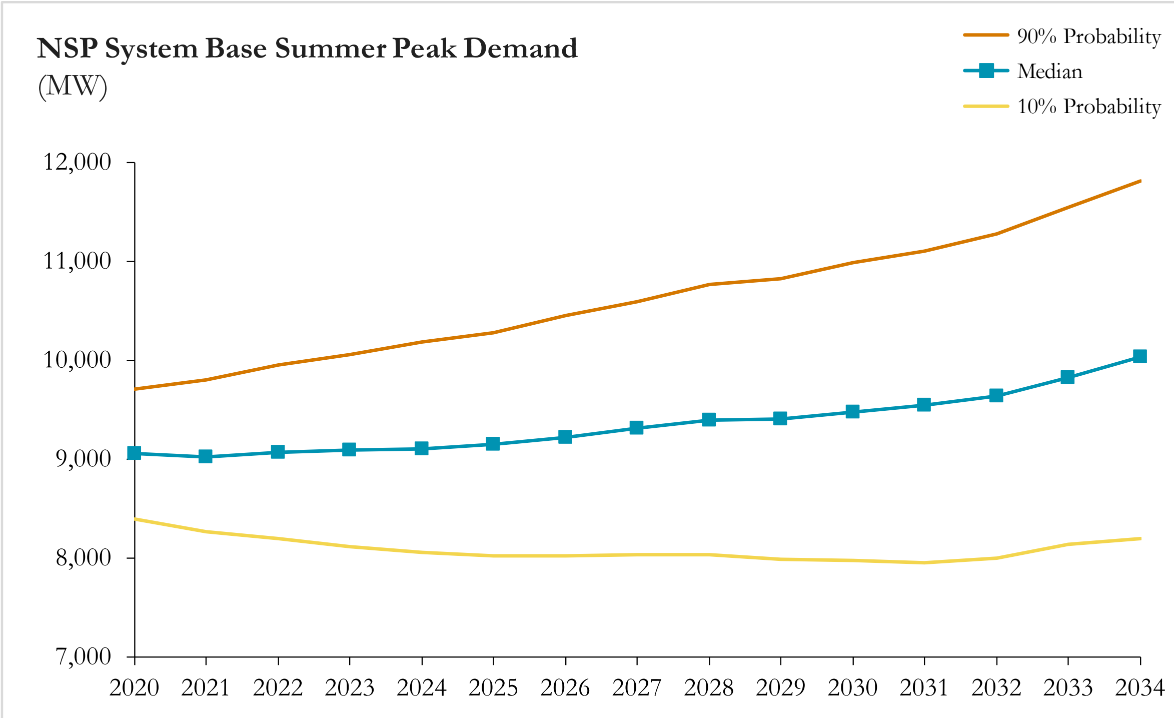
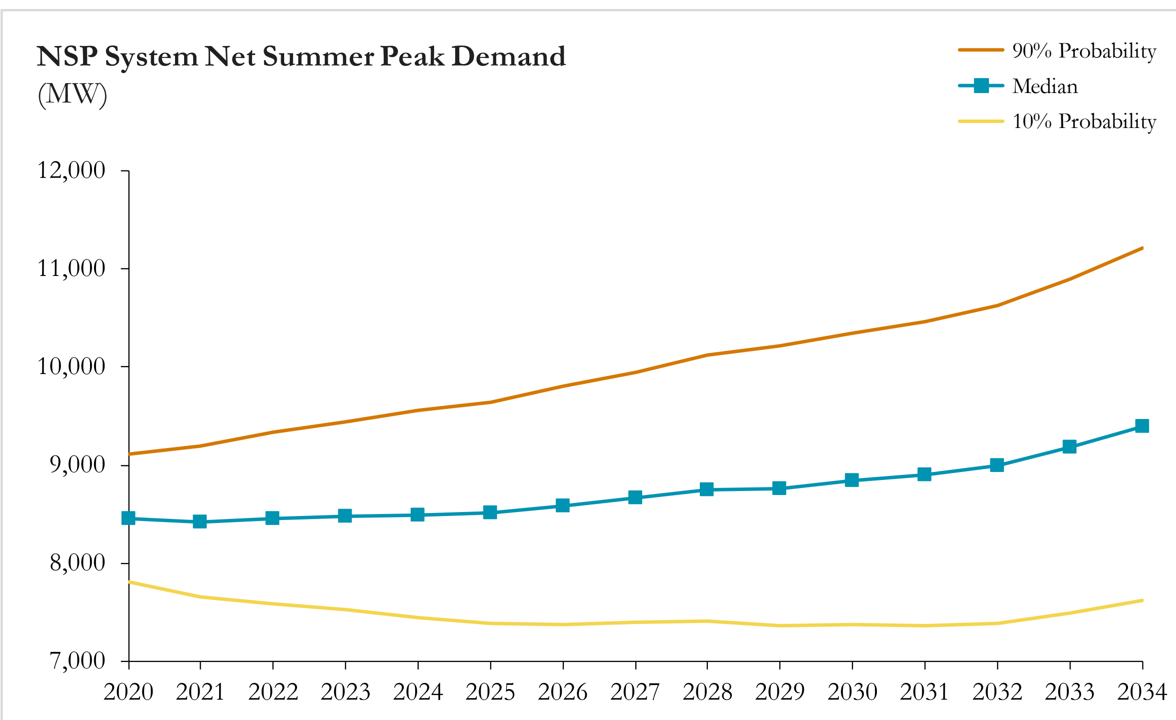


Figure II-9: NSP System Total Net Summer Peak Demand



Tables II-1, II-2, and II-3 below provide the data underlying Figures II-7, II-8, and II-9, respectively.

Table II-1: Annual Net Energy (MWh)

Year	90% Probability	Median	10% Probability
2020	45,476,686	43,061,970	40,919,797
2021	45,272,408	42,606,809	40,164,021
2022	45,442,181	42,471,834	39,760,912
2023	45,448,683	42,262,626	39,266,438
2024	45,581,547	42,140,430	38,885,430
2025	45,789,703	42,103,713	38,605,884
2026	46,162,866	42,228,105	38,463,143
2027	46,704,396	42,493,983	38,416,797
2028	47,415,952	42,936,296	38,585,387
2029	47,382,221	42,700,049	38,113,206
2030	47,855,827	42,896,785	38,043,364
2031	48,291,300	43,072,712	37,948,552
2032	49,077,682	43,533,978	38,132,993
2033	49,989,767	44,142,411	38,395,001
2034	51,261,533	45,016,323	38,887,528
Average Annual Growth 2020 - 2034	**0.9%**	**0.2%**	**-0.6%**

Table II-2: Annual Base Summer Peak Demand (MW)

Year	90% Probability	Median	10% Probability
2020	9,704	9,058	8,390
2021	9,799	9,028	8,268
2022	9,952	9,066	8,196
2023	10,062	9,097	8,114
2024	10,186	9,108	8,053
2025	10,284	9,154	8,020
2026	10,452	9,219	8,018
2027	10,596	9,313	8,033
2028	10,762	9,396	8,041
2029	10,831	9,409	7,985
2030	10,991	9,480	7,980
2031	11,105	9,546	7,954
2032	11,276	9,634	7,996
2033	11,543	9,830	8,139
2034	11,811	10,033	8,201
Average Annual Growth 2020 - 2034	**1.4%**	**0.7%**	**-0.3%**

Table II-3: Annual Net Peak Demand (MW)

Year	90% Probability	Median	10% Probability
2020	9,112	8,457	7,812
2021	9,190	8,419	7,659
2022	9,336	8,452	7,587
2023	9,441	8,477	7,526
2024	9,563	8,486	7,447
2025	9,634	8,514	7,383
2026	9,800	8,579	7,377
2027	9,947	8,669	7,395
2028	10,118	8,752	7,405
2029	10,216	8,765	7,365
2030	10,347	8,836	7,369
2031	10,461	8,902	7,365
2032	10,632	8,990	7,383
2033	10,899	9,186	7,495
2034	11,208	9,389	7,620
Average Annual Growth 2020 - 2034	**1.5%**	**0.7%**	**-0.3%**

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.

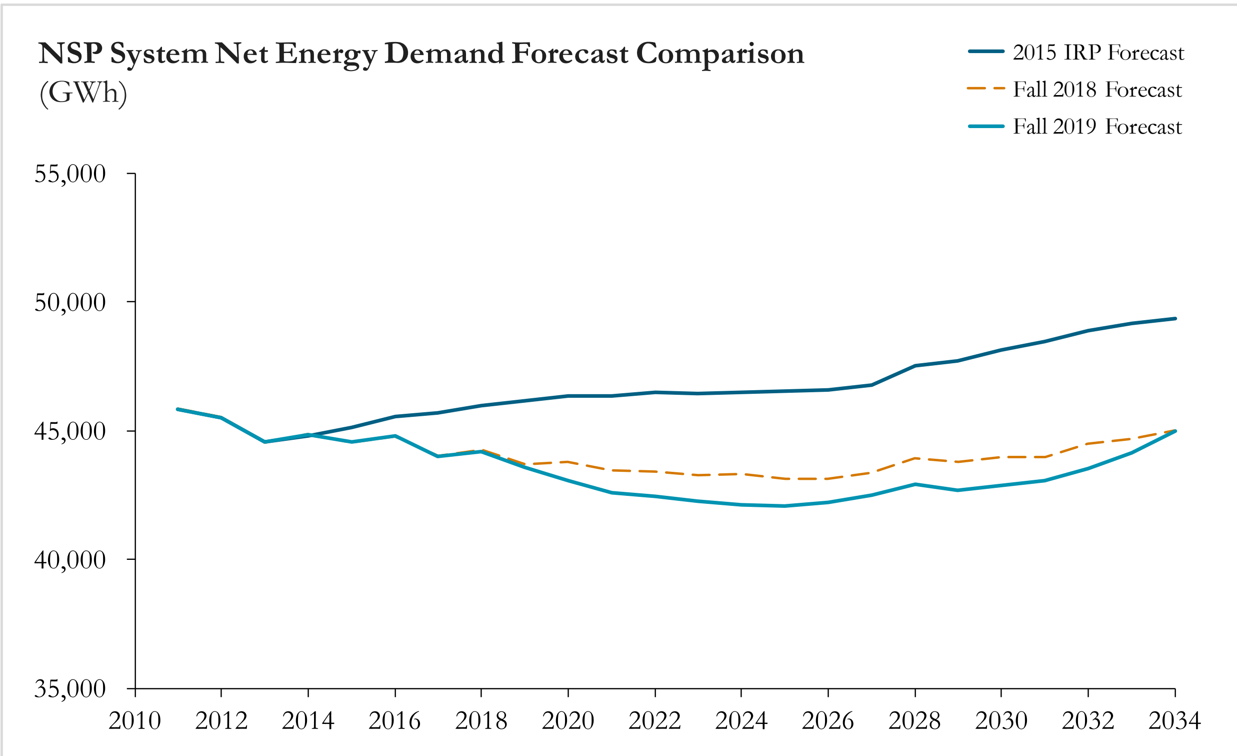
1. Forecast Vintage and Comparison

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 fall 2019 forecast with both the forecasts filed 2015 Resource Plan and the forecasts filed in our Initial 2020-2024 Resource Plan.

Figure II-10 below indicates that the fall 2019 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, 2017, and 2018. In particular, 2015-2018 weather normalized actual sales were lower for the NSP Minnesota (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.

The fall 2019 forecast is also slightly lower than fall 2018 forecast, used in our Initial filing in this docket. There are several factors influencing these adjustments. First, we experienced lower than expected weather-normalized sales from June 2018 through May 2019, the 12-month period between when the fall 2018 forecast was developed and when the fall 2019 forecast was developed. Further, our fall 2019 forecast vintage anticipates additional energy efficiency savings going forward relative to the fall 2018 forecast. We have also adjusted expectations around small commercial and industrial class sales during the interval between the fall 2018 and fall 2019 forecasts. For example, the fall 2019 forecast was adjusted to remove specific large commercial and industrial load expansions plans that were anticipated in the fall 2018 forecast but later canceled. Finally, the fall 2019 forecast vintage anticipates increased load from electric vehicle adoption in the out years of the forecast, exhibited by a steeper growth trajectory after 2030.

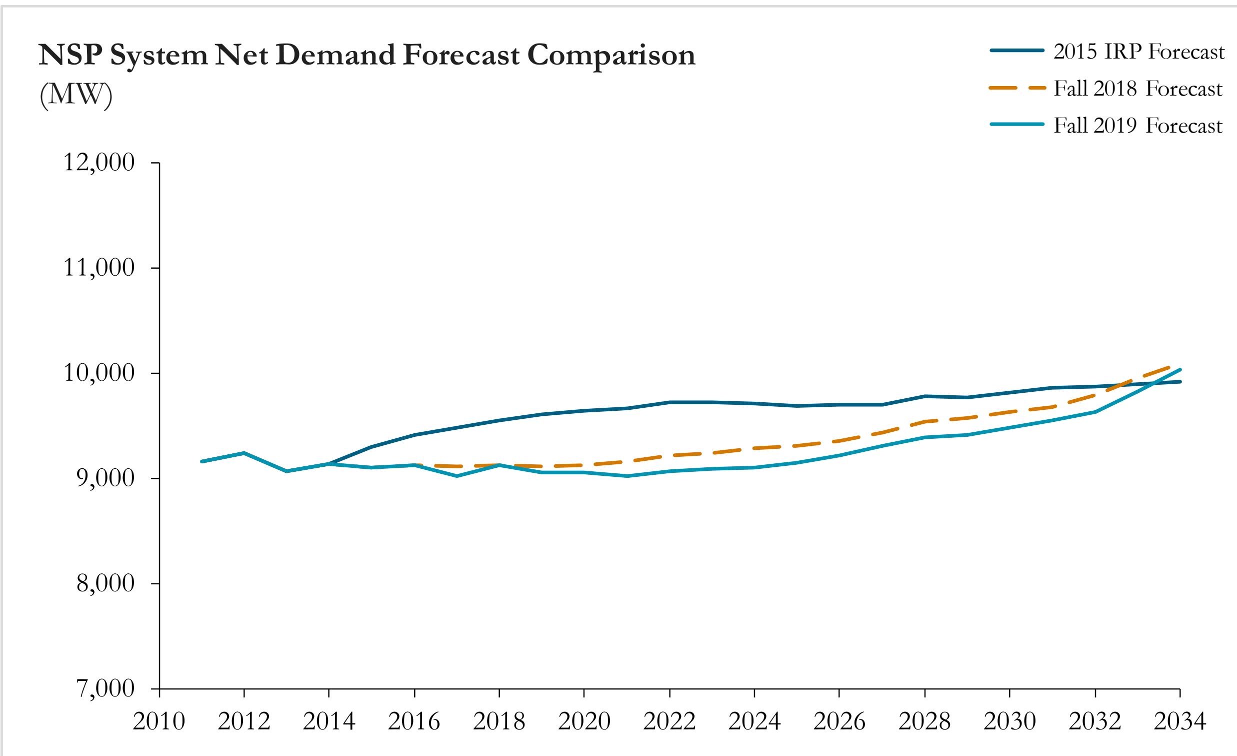
Figure II-10: Net Energy Requirements– Comparison of Current and Previous Energy Forecast
Median (50th Percentile) Forecast



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 0.6 percent, compared to the projected 1.1 percent in the fall 2014 forecast.

Figure II-11 below shows a comparison of the fall 2019 base peak demand forecast to the fall 2014 and 2018 forecasts. 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 2018 have trended downward, the NSP system peak demand has remained fairly flat, but 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. As discussed above, the fall 2019 peak forecast is lower than the fall 2018 forecast due to the lower sales forecast. However, by the end of the planning period, the fall 2019 forecast returns to the level of the fall 2018 peak forecast, as a result of anticipated growing electric vehicle load.

Figure II-11: Base Peak Demand – Comparison of Current and Previous Demand Forecast
Median (50th Percentile) Forecast



III. DISTRIBUTED ENERGY RESOURCE FORECASTS

This section discusses the DER forecasts used in our Supplement analyses.

A. Distributed Solar

We offer several programs to customers who are interested in distributed solar. 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. Until its discontinuance, Minnesota customers also had the opportunity to participate in the Made in Minnesota program. Customers may also choose a net metered option for on-site solar. Both our Reference and High adoption forecast cases take all these programs into account, at varying growth rates.

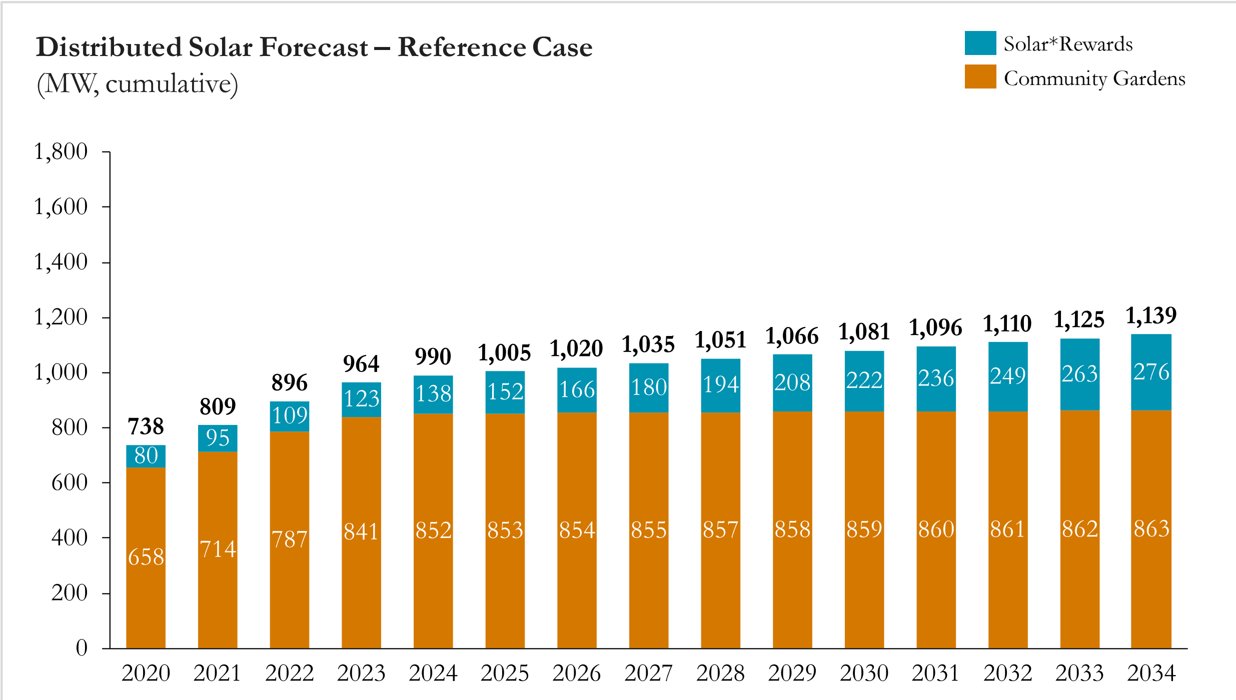
1. Reference Case

In determining our Reference Case, we updated our forecasted adoption levels 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. We based attrition and completion lag rates on historical analysis of cancelled and completed projects, and subsequently applied them to program application forecasts to derive final installation estimates.

Due to the large response to date for our Solar*Rewards Community program – which has no statutory budget or capacity limits – we forecast additions of 738 MW through 2020. For our Reference Case assumptions, we assume DG solar grows at approximately 15 MW per year after 2023. This assumption takes into account significant early adoption of Community Solar Gardens (CSGs) and a going-forward reduction in tax benefits. These projections are consistent with those included in our 2019 Integrated Distribution Plan (IDP).

Figure III-1 below provides our Reference Case forecast of distributed solar additions.

Figure III-1: Reference Case NSP System Distributed Solar Forecast



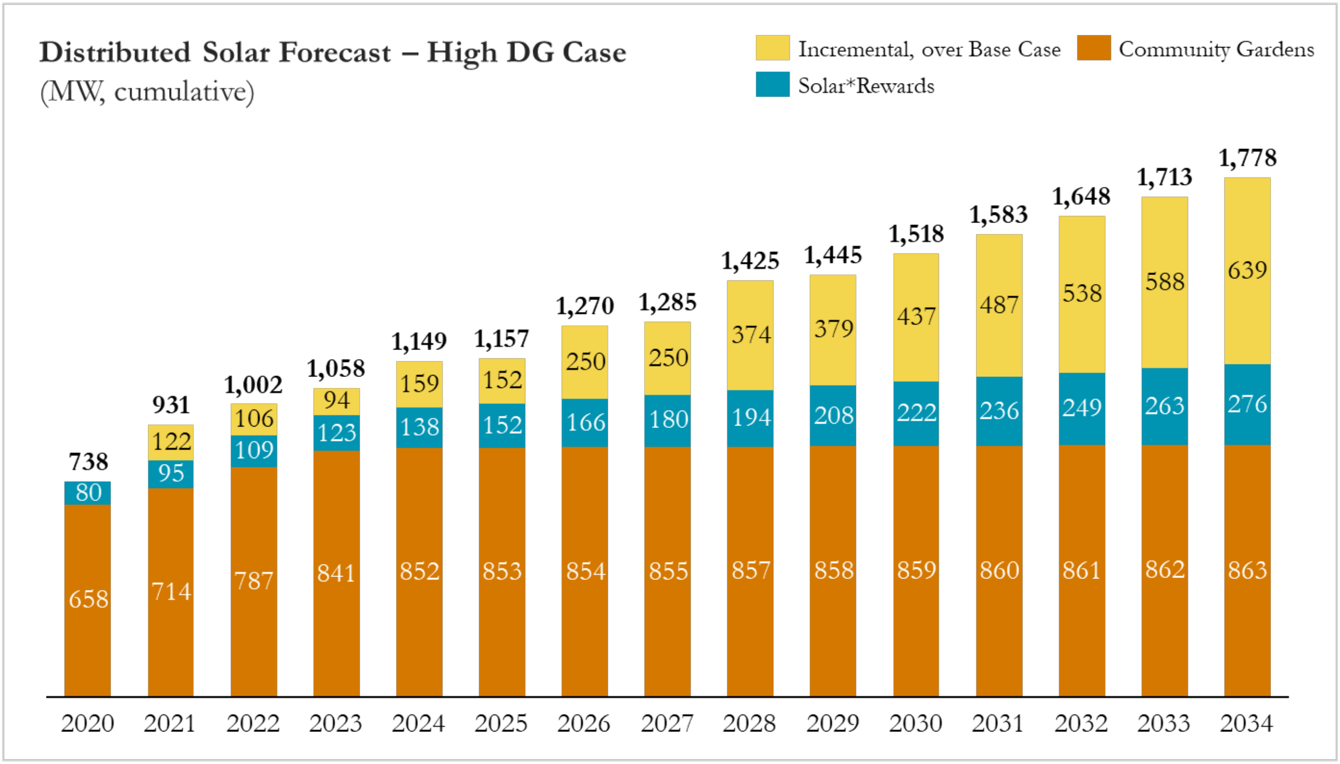
2. *High Distributed Solar Scenario*

In the High adoption scenario, Solar*Rewards and Made in Minnesota are consistent with the Reference Case, for the reasons discussed above. For net metering and CSG in this scenario, however, we assume growth, over and above the Reference Case. This growth is not differentiated by program, as net metering and CSG can generally be thought of as substitutes for each other. For example, we estimate that total solar PV in 2034 is approximately 1,780 MW – of which, approximately 640 MW may be either net metering or CSG.

To develop the High Distributed Solar adoption scenario, we forecasted potential adoption using a Payback adoption model that assumes a 10 percent reduction to the solar installation cost curve, relative to the base case, starting in 2020. The Payback model results indicates a High adoption case forecast of around 1,778 MW of total installed distributed solar by 2034.

We provide the High Distributed Solar scenario forecast below.

Figure III-2: High Distributed Solar Adoption Scenario Forecast



B. Distributed Wind

The NSP System presently has little distributed wind; there are a total of 68 projects that comprise 16 MW, with an additional eight projects in the queue comprising less than 1 MW total. We believe solar PV and distributed storage adoption will account for most of our future DER growth – as both have developed rapidly and are easier for most customers to adopt – and that distributed wind will continue to be a very small proportion of DER on our distribution system. Additionally, there is little information available in the industry regarding the adoption of distributed wind. For these reasons, we have not factored distributed wind installation projections into our Resource Plan forecasts.

C. Distributed Energy Storage

From January 2017 through December 2019 we received 79 interconnection applications to connect distributed energy storage to our Minnesota electric distribution system. Of these 79 storage system applications, 47 are complete and in operation. The current total behind the meter battery storage installed on our Minnesota distribution system is approximately 0.77 MW. We provide an annual breakdown of storage applications received and completed below:

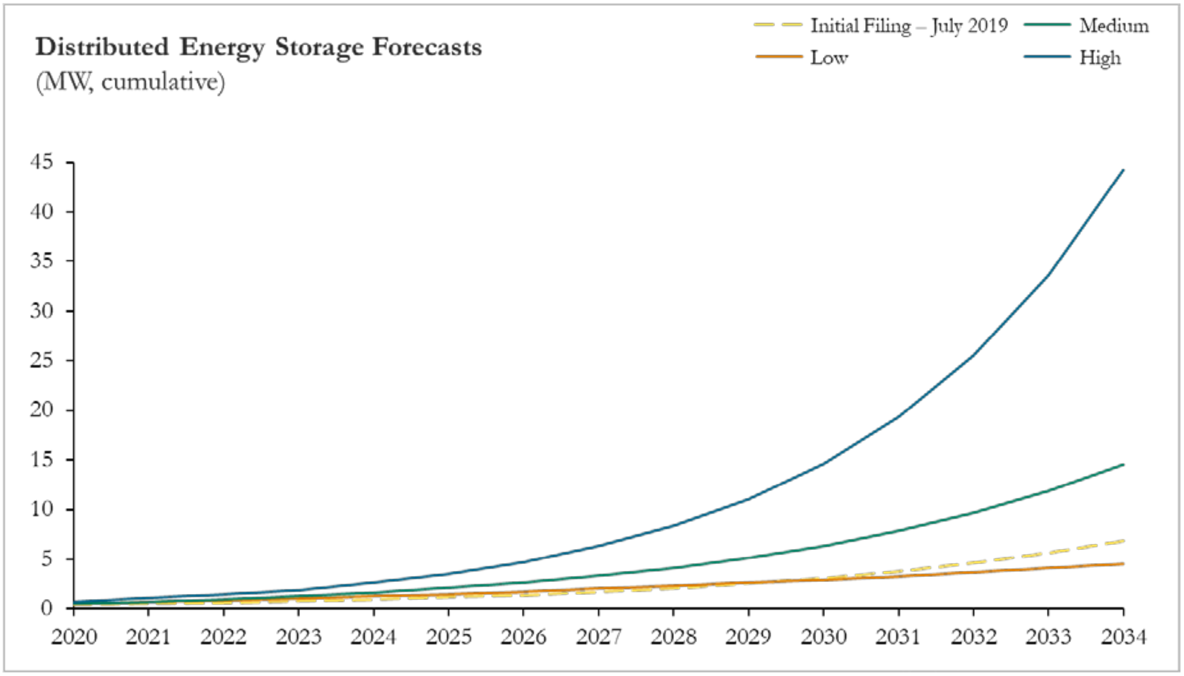
Table III-1: Storage Applications through December 2019 – NSPM, State of Minnesota

Application Year	Total Projects	Number of Projects Completed by Year			Total MW Completed	Projects In Queue
		2017	2018	2019		
2017	18	6	11	0	0.09	1
2018	25	---	12	10	0.39	3
2019	36	---	---	8	0.29	28
Total	**79**	**6**	**23**	**18**	**0.77**	**32**

In order to forecast distributed storage for our system, we utilize our system's current adoption numbers in conjunction with available data from industry consulting firms that specialize in tracking current market conditions and forecasting trends. We have found that the availability of detailed market information on distributed energy storage is limited for the state of Minnesota. Wood Mackenzie, however, currently publishes a quarterly report (U.S. Energy Storage Monitor) which provides high-level trends and forecasts that can be utilized to extrapolate a possible scenario for distributed energy storage within the Company's Minnesota electric distribution system. The Scenarios discussed below are consistent with those used in our 2019 IDP through 2029, and further extrapolated for 2030-2034 using consistent year over year growth rates.

For Scenario 1 entitled "High," we utilized the actual completed energy storage units for NSP Minnesota in years 2017 and 2018 and then applied the forecasted forward growth rates as provided by Wood Mackenzie's most recent forecast for behind the meter storage additions. For Scenario 2, entitled "Mid," we utilized a growth rate forecast from Navigant Research's Global DER Overview that estimates a growth rate of 21.9 percent for distributed energy storage systems. The model extrapolates the current number of installations on the NSP Minnesota system at the Navigant projected rate of growth. We used one additional modeling technique to develop Scenario 3 entitled "Low," which uses a time series analysis of the historical average rate of internal applications received for energy storage systems, as tracked by NSP Minnesota. This alternate scenario models the average number of applications received per month during 2017 and 2018 and then extrapolates a continued growth rate of monthly applications received through 2029, in alignment with the IDP planning period. As in the Reference scenario, we assume a continued growth trend beyond 2029.

Figure III-3: Distributed Energy Storage Systems Growth Forecast



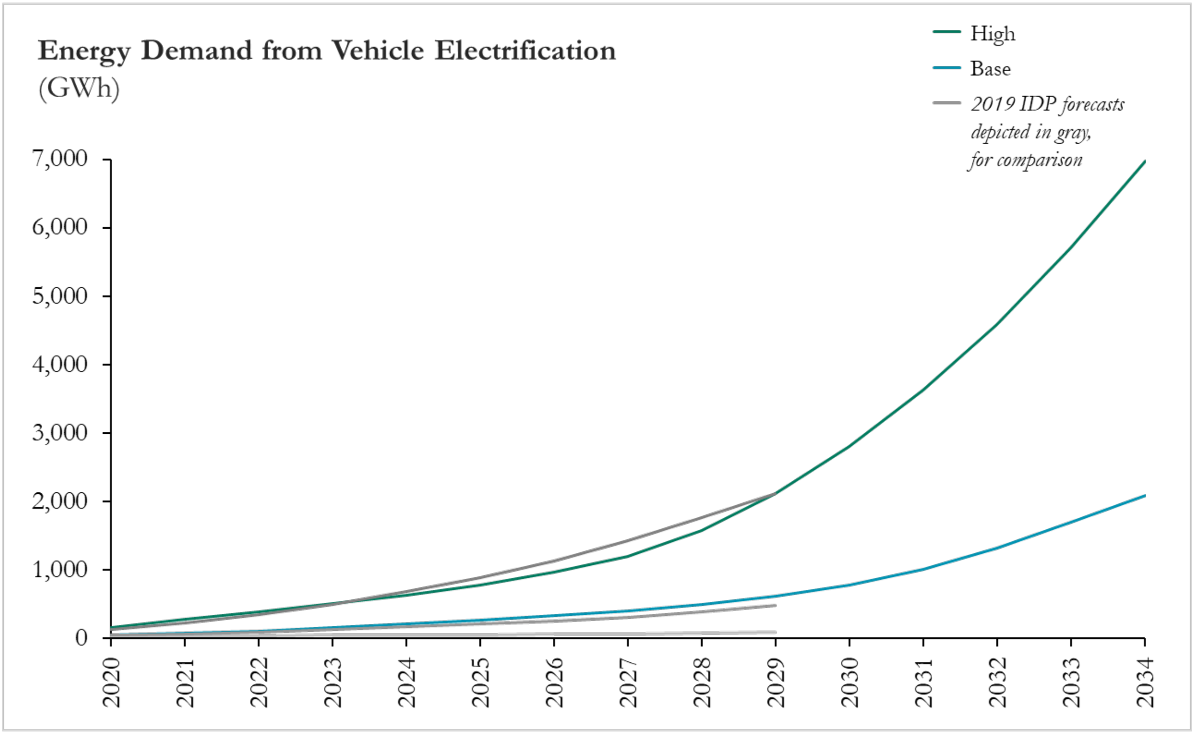
Utilizing all scenarios in conjunction with an estimated average MW for each respective unit deployed, the total cumulative MW of distributed energy storage is not expected to exceed 12 MW by 2029. Even in the most aggressive scenario, with rapid growth, total installed capacity remains under 50 MW by 2034.

That said, distributed energy storage within Minnesota is a nascent market. As such, we note that the various scenarios we have developed are sensitive to exogenous factors such as policy changes, technology advancements and learning curves, and geopolitical risks that could affect raw material availability.

D. Electric Vehicles

With the increase of available models EV market adoption has increased in the U.S. to approximately 1.3 million as of December 2019. At the same point there were approximately 12,000 EVs in the state of Minnesota, and the number continues to increase. As noted above, we include energy demand from Base EV adoption in our corporate forecasts; however, we have also tested a High Adoption sensitivity forecast. The methodologies behind these forecasts are discussed further below.

Figure III-4: Electrification Scenarios used in the Supplement Resource Plan Analysis



1. *Base EV Adoption*

Our Base EV forecasts estimate EV adoption using two modeling techniques: 1) Bass Technology Diffusion, and 2) Econometric models. Bass Diffusion models are used to describe technology adoptions patterns in an existing market through an "S" shaped diffusion characteristic. Econometric models use simple payback analysis to estimate potential adoption, incorporating factors such as battery prices, tax incentives, fuel savings and others. After establishing forecasts through both methods, we average the results to estimate base EV adoption in our service area. This results in a cumulative base case adoption estimate of approximately 15 percent of all registered cars and light trucks by 2034. Below we describe both forecasting methods in more detail.

- *Bass Diffusion Modeling.* The Bass Diffusion model approach is now calibrated using state-specific historical EV sales, as well as data through December 2018. The high and low scenarios for the Bass Diffusion models are created using data from states that reflect high historical adoption rates for the high scenario, and low historical adoption rates for the low scenario.

- *Econometric Modeling.* For the econometric modeling approach, we create high and low adoption scenarios that were developed around the base scenario, and that primarily differ in their assumptions on battery and gasoline pricing. Other variables impacting adoption are available tax incentives, and fuel savings. We rely on variation in battery pricing because analysis indicates battery costs are the primary factor for higher EV prices. The high adoption scenario assumes the battery prices are 20 percent lower than the medium scenario, and gasoline prices are higher by one standard deviation. Conversely, the low adoption scenario assumes battery prices are 20 percent higher than the medium scenario, and gasoline prices lower by one standard deviation.

Additionally, we have incorporated into both the Bass diffusion and econometric models a factor for the percentage of vehicles in urban and rural areas. Presently higher adoption is occurring in urban areas with the rural areas anticipated to ramp up slowly.

We believe the forecasting approach we took for this Supplement represents an improvement relative to our previous methodologies and works to bring in line the forecasts used across our most recent IDP and this Supplement. For example, where previously the IDP forecast significantly more adoption than the Resource Plan's Base Case, these forecasts are now generally consistent through the IDP forecast period, as depicted in the figure above. Our estimates show significant volatility between various scenarios, however. The estimates are also sensitive to several exogenous variables – similar to those discussed in the Distributed Energy Storage section above – because battery market dynamics are a significant factor in the cost of EVs. These may include policy, technology, manufacturing supply chain, and geopolitical factors, among others. We have also proposed several customer programs in our Minnesota service area to address increasing customer appetite for transportation electrification solutions, and we engage stakeholder input through an advisory group for these pilots and programs.

Since we are in the early stages of EV adoption, we expect our future estimates will be increasingly robust as we continue to update our models, when new data becomes available. As a result of the nascent market and significant uncertainties, there is a broad range of possible outcomes. We would expect as the market continues to grow, our future forecasts will reflect methodology and input developments that will cause these outlooks to change in the future.

2. *High Electrification Sensitivity*

Consistent with our initial Resource Plan, the High Electrification Scenario included here represents a load forecast sensitivity derived from the E3 statewide decarbonization analysis using PATHWAYS. [25] The objective of this sensitivity was to create a "high bookend," examining the possible impacts on load growth and peak demand growth on our system under a scenario with a level of electrification that would achieve Minnesota's economy-wide goal of an 80 percent reduction in greenhouse gas (GHG) emissions below 2005 levels by 2050.[26] This forecast represents a much higher level of EV adoption than our Base Case, but also includes other beneficial electrification measures. We provide more detailed information regarding the E3 High Electrification sensitivity in Appendix F4 of our initial filing.

[25] 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 to our Initial Filing.

[26] Per Minn. Stat. 216H.02, Subd. 1. *See* https://www.pca.state.mn.us/air/state-and-regional-initiatives

IV. MODELING ASSUMPTIONS AND INPUTS

Since filing our initial Resource Plan in July 2019, the Company has made several changes to its modeling approaches, inputs, and assumptions. Some of these changes in modeling approaches implemented based on discussions with the Department of Commerce (DOC or Department), and feedback from the Commission and stakeholders. Others reflect the passage of time and availability of more recent input and assumptions source material. While a more complete set of updated Strategist and EnCompass modeling assumptions is included in this section, we provide a summary of major changes below.

Topic	Assumption	Change from Initial Filing	Rationale for Change	Sensitivity Performed?
Modeling constraints				
Carbon emissions constraint	▪ No constraint; baseload scenarios may not meet 80 percent reduction goal	▪ Removed modeling constraint of 80 percent carbon reduction by 2030	▪ Alignment with DOC preferred approach	▪ None
"No Going Back" wind replacement capacity	▪ No assumption that existing wind will be replaced when plants or contracts reach end of life	▪ Removed wind replacement capacity from baseline modeling	▪ Alignment with DOC preferred approach	▪ None
Reliability Requirement	▪ Modeling does not include 5.7 GW firm, dispatchable capacity floor; model optimizes resources to develop expansion plans	▪ Removed reliability requirement from baseline modeling	▪ EnCompass modeling better accounts for reliability in hourly chronological modeling ▪ Alignment with DOC preferred approach	▪ None

Topic	Assumption	Change from Initial Filing	Rationale for Change	Sensitivity Performed?
Near term wind availability constraint	▪ No generic wind option made available for model to select before 2026	▪ Generic wind available to select in modeling for each year	▪ Transmission constraints in near term are highly cost prohibitive, such that most greenfield projects are withdrawing from the interconnection queue	▪ Tested alternate sensitivity where wind is available in 2023
Market sales limit	▪ Limits market sales to 25 percent of retail load in EnCompass modeling	▪ Not applicable; no market sales limit capability in Strategist	▪ Limit sales risk exposure	▪ Tested alternate scenarios with unlimited market
Market and technology assumptions				
Market hourly price shaping	▪ Shaped hourly market prices based on retail load	▪ Hourly market price shaped based on thermal load	▪ Alignment with DOC preferred approach	▪ None
Fuel price forecasts	▪ Updated to Fall 2019 forecast vintage	▪ Changed from vintage available prior to previous filing	▪ Previous inputs outdated	▪ High and low fuel price forecasts
Technology price forecasts for wind, solar, and storage	▪ Used National Renewable Energy Labs (NREL) *Annual Technology Baseline (ATB) 2019* assumptions	▪ Updated from 2018 ATB to 2019 ATB for wind and solar ▪ Shifted from using internal price assumptions to 2019 ATB for storage	▪ Previous inputs outdated	▪ Used High and low technology price forecasts in sensitivities

Topic	Assumption	Change from Initial Filing	Rationale for Change	Sensitivity Performed?
Wind resource production	▪ Used 2019 NREL ATB price inputs for Technology Resource Group (TRG) 2	▪ Previously used 2018 ATB price assumptions for TRG 1, which reflected a higher capacity factor expectation	▪ We believe TRG 2 capacity factors better align with wind resource quality for remaining sites in our region	▪ None
Solar resource production	▪ Assumed 22 percent capacity factor in first year, with 0.5 percent per year degradation	▪ Previously assumed 17.7 percent levelized capacity factor	▪ Better alignment with performance of our existing solar resources	▪ None
Renewable transmission interconnect cost	▪ Wind: $500/kW ▪ Solar: $200/kW	▪ Wind: Increased from $400/kW for greenfield wind ▪ Solar: Increased from $140/kW	▪ MISO transmission constraints create upward pressure on interconnection costs	▪ None
Solar capacity accreditation	▪ 50 percent ELCC to 2023, declining to 30 percent in 2033 at a rate of 2 percent per year	▪ 50 percent ELCC for the full analysis period	▪ Aligns with assumptions used in MISO MTEP 2019 modeling	▪ Performed alternate scenario with 50 percent ELCC held constant

Topic	Assumption	Change from Initial Filing	Rationale for Change	Sensitivity Performed?
Wind capacity accreditation	▪ 16.7 percent ELCC throughout the planning period	▪ 15.6 percent ELCC throughout the planning period	▪ Updated to reflect MISO Zone 1 ELCC rather than MISO-wide assumptions ▪ Updated to match MISO's most recent Wind and Solar Capacity Credit report.	▪ None
Effective Reserve Margin	▪ Reserve margin updated to 3.46 percent, based on latest MISO LOLE Study (2020-2021)	▪ 2.98 percent effective reserve margin	▪ Updated to most recent LOLE study result	▪ None
Upper Midwest System Assumptions				
Unit retirement dates	▪ All existing unit retirement years with end of financial life	▪ Selected units used differing retirement dates for resource planning purposes	▪ Conforms with Commission direction	▪ None
Seasonal coal dispatch	▪ King and Sherco 2 do not dispatch from March-May and September-November, through 2023	▪ No units were modeled with seasonal dispatch	▪ Reflects Commission-approved operational practices	▪ None
Load forecasts	▪ Updated to fall 2019 internal forecast vintage	▪ Changed from fall 2018 internal forecast	▪ Previous inputs outdated	▪ None

Topic	Assumption	Change from Initial Filing	Rationale for Change	Sensitivity Performed?
DER forecasts	▪ Updated to latest vintage for each technology	▪ Changed from vintage available prior to previous filing	▪ Previous inputs outdated	▪ Sensitivity on low load/high DER adoption
EV adoption forecasts	▪ Updated to latest vintage, aligned with most recent forecasts used in IDP	▪ Changed from vintage available prior to previous filing	▪ Previous inputs outdated ▪ Conforms with Commission direction to better align forecasts across filings	▪ Sensitivity on high EV adoption
Nuclear budgets	▪ Updated to most recent vintage for Nuclear Decommissioning Trust, Operations and Maintenance and Capital Expenditure budgets	▪ Changed from vintage available prior to previous filing	▪ Previous inputs outdated	▪ None

A. Discount Rate and Capital Structure

The discount rate used for levelized cost calculations and the present value of modeled costs is 6.47 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 IV-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	45.72%	4.79%	2.19%	1.58%
Common Equity	52.39%	9.25%	4.85%	4.85%
Short-Term Debt	1.89%	3.55%	0.07%	0.05%
Total			**7.10%**	**6.47%**

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 percent 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 8.9 percent from the 2020-2021 LOLE Study Report, published November 2019. The coincidence factor between the NSP System and MISO system peak is 95 percent. Therefore, the effective reserve margin is:

$$(95\,percent\ coincidence\ factor) x\ (1 + 8.9\,percent) - 1 \\ = \mathbf{3.46}\,percent\ effective\ reserve\ margin\ for\ NSP$$

D. CO_2 Costs

The Present Value of Societal Cost (PVSC) Base Case CO_2 values are based on the high environmental cost values for CO_2 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 Gross Domestic Product Implicit Price Deflator (GDPIPD) of 113.416 and then escalated 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 E999/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 IV-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 three 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 GDPIPD of 113.416. The high, low and midpoint externality costs will be used in the CO_2 sensitivities as described above.

Table IV-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 2019 load forecast is used as the base assumption and assumes that EV impacts growth continues throughout the forecast period. The energy efficiency (EE) forecast included in the base forecast developed by the Company's Load Forecasting department assumes somewhat less energy efficiency (EE) savings levels than those included in our initial Resource Plan's Preferred Plan. Please see Attachment A Section II for more information.

The "Load Forecast with EE" shown in Table IV-4 below is the starting point for the load inputs. In all modeling scenarios, the "EE" is removed – the removal of these EE program effects, which have a 14-year life, impacts the load forecast through 2048. In the initial filing, the three EE Bundles (discussed below) were optimized as Proview Alternatives. For this supplemental filing, the first two EE Bundles are included in all scenarios. The resulting forecast, before the optimized EE bundles are added, is shown below in Table IV-4 as "Forecast Without EE." The forecasts shown do not include the impact of DG solar, as DG solar is modeled as a resource, not a load modifier.

Table IV-4: Demand and Energy Forecast

Demand and Energy Forecast				
	Demand (MW)		Energy (GWh)	
Year	Forecast with EE	Forecast without EE	Forecast with EE	Forecast without EE
2018	9,152	9,152	43,914	43,914
2019	9,084	9,084	43,558	43,558
2020	9,099	9,230	43,170	43,806
2021	9,079	9,312	42,741	44,018
2022	9,126	9,462	42,628	44,549
2023	9,165	9,604	42,440	45,004
2024	9,184	9,728	42,339	45,555
2025	9,238	9,849	42,324	45,976
2026	9,311	9,992	42,470	46,565
2027	9,414	10,164	42,757	47,296
2028	9,504	10,327	43,221	48,216
2029	9,525	10,416	43,006	48,432
2030	9,605	10,566	43,224	49,093
2031	9,679	10,710	43,420	49,734
2032	9,775	10,880	43,903	50,678
2033	9,979	11,058	44,532	51,299
2034	10,190	11,246	45,426	52,203
2035	10,343	11,269	46,158	52,299
2036	10,502	11,325	47,028	52,527
2037	10,673	11,393	47,647	52,503
2038	10,803	11,420	48,209	52,422
2039	10,936	11,449	48,833	52,394
2040	11,073	11,518	49,603	52,729
2041	11,209	11,585	50,055	52,737
2042	11,338	11,645	50,635	52,873
2043	11,467	11,701	51,267	53,048
2044	11,614	11,780	52,023	53,374
2045	11,722	11,818	52,468	53,375
2046	11,839	11,865	53,010	53,473
2047	11,951	11,903	53,545	53,547
2048	12,021	11,998	54,150	54,160
2049	12,045	12,045	54,202	54,202
2050	12,097	12,097	54,407	54,407
2051	12,149	12,149	54,611	54,611
2052	12,199	12,199	54,947	54,947
2053	12,252	12,252	55,022	55,022
2054	12,305	12,305	55,226	55,226
2055	12,357	12,357	55,431	55,431
2056	12,409	12,409	55,765	55,765
2057	12,461	12,461	55,840	55,840

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 IV-5 and Table IV-6 and are incremental/decremental to the forecast shown in Table IV-4.

Table IV-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	592	65
2026	692	77
2027	812	85
2028	939	98
2029	1,202	118
2030	1,578	162
2031	2,028	205
2032	2,538	251
2033	3,137	305
2034	3,857	367
2035	4,716	438
2036	5,657	515
2037	6,672	596
2038	7,741	679
2039	8,851	766
2040	9,996	854
2041	11,114	940
2042	12,199	1,025
2043	13,241	1,118
2044	14,229	1,796
2045	15,159	2,520
2046	16,037	3,173
2047	16,877	3,796
2048	17,696	4,647
2049	18,660	4,908
2050	19,530	5,407
2051	20,634	5,947
2052	21,645	6,418
2053	22,656	6,896
2054	23,666	7,384
2055	24,677	7,877
2056	25,688	8,352
2057	26,699	8,840

**Demand values are coincident to system peak*

Table IV- 6: Low Load Sensitivity

High DER Growth		
Year	Energy (GWh)	Demand (Nameplate MW)
2018	0	0
2019	0	0
2020	0	0
2021	207	122
2022	180	106
2023	159	94
2024	270	159
2025	258	152
2026	423	250
2027	423	250
2028	635	374
2029	641	379
2030	740	437
2031	826	487
2032	913	538
2033	996	588
2034	1,082	639
2035	1,167	689
2036	1,256	739
2037	1,338	790
2038	1,423	840
2039	1,509	891
2040	1,598	941
2041	1,631	963
2042	1,580	933
2043	1,529	903
2044	1,482	872
2045	1,425	842
2046	1,350	797
2047	1,296	765
2048	1,245	733
2049	1,187	701
2050	1,131	668
2051	1,063	628
2052	1,009	594
2053	932	550
2054	872	515
2055	807	476
2056	742	437
2057	671	396

G. Energy Efficiency Bundles

The EE "Program" and "Maximum" Bundles are based on the Minnesota DOC's Minnesota Energy Efficiency Potential Study: 2020-2029 published December 4, 2018. The "Optimal" Bundle was developed by the Company. The bundles are decremental (reducing energy and demand) to the "Forecast without EE" shown in Table IV-4.

Table IV- 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. In the initial filing, the three DR Bundles were optimized as Proview Alternatives. For this Supplement, the first DR Bundle is included in all scenarios.

Table IV-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	852	0	0	0	0	0	0
2019	928	0	0	0	0	0	0
2020	1012	33	107	90	1,752	7,659	11,311
2021	1027	165	112	98	8,917	8,150	12,587
2022	1041	232	117	107	12,748	8,676	14,016
2023	1055	294	121	110	16,489	9,137	14,758
2024	1066	341	133	101	19,512	10,277	13,829
2025	1072	382	145	92	22,305	11,459	12,858
2026	1077	394	152	93	23,475	12,207	13,326
2027	1078	407	159	95	24,786	13,080	13,845
2028	1077	423	168	97	26,245	14,086	14,418
2029	1071	440	178	99	27,859	15,231	15,047
2030	1059	458	190	102	29,637	16,522	15,734
2031	1048	478	202	104	31,551	17,926	16,467
2032	1037	499	215	107	33,612	19,451	17,251
2033	1026	521	228	110	35,832	21,109	18,088
2034	1016	545	243	113	38,224	22,911	18,984
2035	1005	570	259	116	40,802	24,870	19,943
2036	995	596	275	120	43,582	26,999	20,971
2037	985	624	293	123	46,580	29,313	22,072
2038	976	654	312	127	49,814	31,829	23,253
2039	966	686	332	132	53,305	34,564	24,522
2040	957	720	353	136	57,073	37,537	25,884
2041	948	720	353	136	58,215	38,288	26,402
2042	939	720	353	136	59,379	39,054	26,930
2043	930	720	353	136	60,566	39,835	27,468
2044	922	720	353	136	61,778	40,632	28,018
2045	914	720	353	136	63,013	41,444	28,578
2046	906	720	353	136	64,274	42,273	29,150
2047	898	720	353	136	65,559	43,118	29,733
2048	890	720	353	136	66,870	43,981	30,327
2049	882	720	353	136	68,208	44,860	30,934
2050	875	720	353	136	69,572	45,758	31,552
2051	868	720	353	136	70,963	46,673	32,183
2052	860	720	353	136	72,382	47,606	32,827
2053	853	720	353	136	73,830	48,558	33,484
2054	847	720	353	136	75,307	49,530	34,153
2055	840	720	353	136	76,813	50,520	34,836
2056	833	720	353	136	78,349	51,531	35,533
2057	827	720	353	136	79,916	52,561	36,244

**Demand values are coincident to system peak.*

I. Fuel Price Forecasts

Natural gas price forecasts are developed using a blend of market information (New York Mercantile Exchange, or NYMEX, 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 IV-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 when the long-term fundamentally-based forecasts are blended with market information (NYMEX futures prices).

Table IV-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	$2.60	$26.93	$20.98	$2.08	$2.60	$26.93	$20.98	$2.08	$2.60	$26.93	$20.98
2020	$2.11	$2.26	$25.78	$20.13	$2.11	$2.26	$25.78	$20.13	$2.11	$2.26	$25.78	$20.13
2021	$2.14	$2.23	$25.32	$19.06	$2.14	$2.23	$25.32	$19.06	$2.14	$2.23	$25.32	$19.06
2022	$2.19	$2.33	$26.92	$20.45	$2.17	$2.28	$26.33	$20.00	$2.24	$2.38	$27.52	$20.90
2023	$2.25	$2.45	$29.31	$22.19	$2.19	$2.34	$27.96	$21.17	$2.36	$2.57	$30.68	$23.23
2024	$2.30	$2.58	$30.00	$23.20	$2.22	$2.40	$27.94	$21.60	$2.46	$2.76	$32.16	$24.87
2025	$2.35	$2.79	$31.47	$24.36	$2.24	$2.50	$28.17	$21.80	$2.57	$3.11	$35.04	$27.12
2026	$2.40	$2.98	$32.30	$24.99	$2.27	$2.58	$28.01	$21.67	$2.69	$3.42	$37.09	$28.70
2027	$2.45	$3.12	$33.35	$26.71	$2.29	$2.64	$28.28	$22.64	$2.81	$3.66	$39.16	$31.36
2028	$2.51	$3.26	$34.09	$26.97	$2.32	$2.71	$28.25	$22.35	$2.93	$3.92	$40.92	$32.38
2029	$2.57	$3.44	$35.21	$28.25	$2.34	$2.78	$28.42	$22.79	$3.07	$4.24	$43.38	$34.80
2030	$2.62	$3.70	$38.27	$30.69	$2.37	$2.88	$29.83	$23.92	$3.20	$4.71	$48.76	$39.09
2031	$2.68	$3.87	$39.33	$32.07	$2.40	$2.95	$29.97	$24.44	$3.35	$5.04	$51.22	$41.77
2032	$2.75	$4.02	$39.75	$33.14	$2.43	$3.01	$29.71	$24.77	$3.51	$5.34	$52.76	$43.99
2033	$2.81	$4.10	$39.93	$33.46	$2.45	$3.03	$29.58	$24.79	$3.67	$5.48	$53.47	$44.80
2034	$2.87	$4.20	$41.13	$34.56	$2.48	$3.07	$30.08	$25.28	$3.83	$5.70	$55.76	$46.86
2035	$2.94	$4.35	$42.15	$35.66	$2.51	$3.13	$30.32	$25.65	$4.00	$6.00	$58.12	$49.17
2036	$2.99	$4.47	$42.79	$36.60	$2.53	$3.17	$30.37	$25.97	$4.14	$6.24	$59.80	$51.13
2037	$3.07	$4.65	$44.00	$38.21	$2.56	$3.24	$30.61	$26.58	$4.36	$6.63	$62.69	$54.44
2038	$3.14	$4.86	$44.95	$39.45	$2.60	$3.31	$30.60	$26.85	$4.58	$7.08	$65.43	$57.42
2039	$3.23	$5.04	$45.82	$40.48	$2.63	$3.37	$30.63	$27.06	$4.83	$7.47	$67.88	$59.98
2040	$3.31	$5.22	$46.61	$41.48	$2.66	$3.43	$30.61	$27.25	$5.06	$7.87	$70.25	$62.53
2041	$3.37	$5.32	$46.52	$41.48	$2.69	$3.46	$30.27	$26.99	$5.26	$8.10	$70.79	$63.12
2042	$3.45	$5.47	$47.61	$42.64	$2.72	$3.51	$30.57	$27.38	$5.51	$8.43	$73.40	$65.74
2043	$3.53	$5.62	$48.37	$43.71	$2.75	$3.56	$30.64	$27.69	$5.77	$8.78	$75.56	$68.28
2044	$3.62	$5.78	$49.72	$44.99	$2.79	$3.61	$31.04	$28.09	$6.05	$9.17	$78.79	$71.29
2045	$3.70	$5.99	$51.23	$46.37	$2.82	$3.68	$31.45	$28.46	$6.31	$9.65	$82.57	$74.73
2046	$3.78	$6.17	$52.49	$47.53	$2.85	$3.73	$31.74	$28.74	$6.59	$10.09	$85.85	$77.73
2047	$3.86	$6.29	$53.27	$48.57	$2.88	$3.77	$31.89	$29.08	$6.88	$10.40	$87.98	$80.22
2048	$3.95	$6.46	$54.39	$49.88	$2.91	$3.82	$32.15	$29.49	$7.20	$10.80	$90.96	$83.42
2049	$4.04	$6.66	$55.69	$50.92	$2.95	$3.88	$32.43	$29.65	$7.53	$11.30	$94.52	$86.43
2050	$4.13	$6.77	$56.64	$51.71	$2.98	$3.91	$32.70	$29.85	$7.87	$11.60	$96.97	$88.53
2051	$4.22	$6.96	$58.23	$53.16	$3.01	$3.96	$33.16	$30.27	$8.21	$12.08	$101.05	$92.24
2052	$4.31	$7.13	$59.62	$54.42	$3.04	$4.01	$33.56	$30.63	$8.57	$12.51	$104.64	$95.53
2053	$4.41	$7.29	$61.00	$55.68	$3.08	$4.06	$33.94	$30.99	$8.94	$12.95	$108.29	$98.85
2054	$4.50	$7.46	$62.38	$56.95	$3.11	$4.10	$34.33	$31.34	$9.33	$13.39	$111.97	$102.21
2055	$4.60	$7.62	$63.76	$58.21	$3.14	$4.15	$34.71	$31.69	$9.73	$13.83	$115.69	$105.61
2056	$4.69	$7.79	$65.15	$59.47	$3.17	$4.19	$35.09	$32.03	$10.12	$14.28	$119.45	$109.05
2057	$4.79	$7.95	$66.53	$60.73	$3.21	$4.24	$35.46	$32.37	$10.52	$14.74	$123.26	$112.52

**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 IV-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	4.57	4.66	4.75	4.85	4.95	5.05	5.15	5.25	5.35	5.46	5.57	5.68	5.80	5.91	6.03	6.15	6.27	6.40	6.53	6.66
	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057
$/kw-mo	6.79	6.93	7.07	7.21	7.35	7.50	7.65	7.80	7.96	8.12	8.28	8.44	8.61	8.79	8.96	9.14	9.32	9.51	9.70	9.89

L. Effective Load Carrying Capability 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 16.7 percent of their nameplate rating per MISO 2020/2021 Wind Capacity Report. The ELCC for generic solar is based on the values provided in MISO's MTEP 2019 in Appendix E,[27] and is 50 percent of the alternating current (AC) nameplate capacity through 2023, declining 2 percent annually to 30 percent by 2033 where it remains for the rest of the forecast period. The ELCC assigned for a generic 4-hour battery is equal to 100 percent of the AC equivalent capacity. The ELCC used for hybrid options are the same as the individual components.

M. Spinning Reserve Requirement

Spinning reserve is the online 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 used to cover events where there are not enough resources or market purchase energy available to meet system energy requirements. In Strategist, this is set to $500/MWh. Encompass uses the default value of $10,000/MWh. The primary reason for this difference is the way the models utilize this input. In Strategist's dispatch approach, the emergency energy is determined after the dispatch, when all resources have been utilized and an energy shortfall still exists. In EnCompass, emergency energy is a "soft constraint" that allows emergency energy to "dispatch" as a last resort resource, in order for the model to find a feasible solution. The EnCompass price is set to a high level to ensure that all other available resources – including those that may have a very high effective $/MWh cost resulting from startup costs spread over a very small required run time – are utilized before emergency energy.

O. 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.

[27] Available at: https://cdn.misoenergy.org//MTEP19%20Appendix%20E-Futures%20Assumptions382958.pdf

We note additionally that interconnection costs for generic resources are included in the capital costs in Table IV-14 in Part U of this section and represent "behind the fence" costs associated with substation and representative gen-tie construction.

Table IV-11: Transmission Delivery Costs

Transmission Delivery Costs				
	CC	CT	Wind	Solar
$/kw	500	200	500	200

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 not included in the model.

Table IV-12: Integration Costs

Integration Costs ($/MWh)		
Year	Wind	Solar
2018	0.00	0.00
2019	0.00	0.00
2020	0.41	0.41
2021	0.42	0.42
2022	0.43	0.43
2023	0.44	0.44
2024	0.45	0.45
2025	0.46	0.46
2026	0.47	0.47
2027	0.48	0.48
2028	0.49	0.49
2029	0.49	0.49
2030	0.50	0.50
2031	0.51	0.51
2032	0.53	0.53
2033	0.54	0.54
2034	0.55	0.55
2035	0.56	0.56
2036	0.57	0.57
2037	0.58	0.58
2038	0.59	0.59
2039	0.60	0.60
2040	0.62	0.62
2041	0.63	0.63
2042	0.64	0.64
2043	0.65	0.65
2044	0.67	0.67
2045	0.68	0.68
2046	0.69	0.69
2047	0.71	0.71
2048	0.72	0.72
2049	0.74	0.74
2050	0.75	0.75
2051	0.77	0.77
2052	0.78	0.78
2053	0.80	0.80
2054	0.81	0.81
2055	0.83	0.83
2056	0.84	0.84
2057	0.86	0.86

Q. Distributed Solar Generation and Community Solar Gardens

The distributed solar and Community Solar Gardens inputs are based on the most recent Company forecasts. Distributed Solar is modeled assuming a degradation of half a percent annually in generation. Community Solar Gardens are modeled assuming a degradation of half a percent annually in generation, and a 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.

Table IV-13: Distributed Solar Forecast

Distributed Solar (Nameplate MW)			
Year	Solar Rewards	Community Gardens	Total
2018	29	246	274
2019	61	504	565
2020	80	658	738
2021	95	714	809
2022	109	787	897
2023	123	841	964
2024	138	852	989
2025	152	853	1,005
2026	166	854	1,020
2027	180	855	1,035
2028	194	857	1,050
2029	208	858	1,066
2030	222	859	1,080
2031	236	860	1,095
2032	249	861	1,110
2033	263	862	1,125
2034	276	863	1,140
2035	290	864	1,154
2036	303	866	1,169
2037	317	867	1,184
2038	330	868	1,198
2039	343	869	1,212
2040	357	870	1,227
2041	370	871	1,241
2042	383	869	1,252
2043	396	852	1,247
2044	409	830	1,239
2045	421	818	1,239
2046	434	814	1,248
2047	447	808	1,255
2048	460	805	1,264
2049	472	805	1,277
2050	491	806	1,297
2051	504	807	1,311
2052	518	808	1,326
2053	531	809	1,340
2054	545	810	1,355
2055	559	811	1,369
2056	572	812	1,384
2057	586	812	1,398

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 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 and solar hourly patterns are developed through a "Typical Meteorological Year" process where individual months are selected from the years 2017-2020 to develop a representative typical year. Actual generation data from the selected months is used to develop the profile for each unit. For units where generation data is not complete or not available, data from a nearby similar unit is used.

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 renewable and battery costs are based on data from the NREL 2019 ATB. Utility-scale wind and solar costs shown in Tables IV-18 through IV-20 include transmission costs from Table IV-11 while DG/distributed solar does not.

The modeling no longer assumes "no going back" on renewables, which was the replacement of renewable resources for a similar resource when they reached the end of their life, but rather allows all renewable additions to be optimized.

In addition to base cost data for renewables, low and high costs are used for various sensitivities. Low and high wind, solar, and battery costs are also based on the 2019 ATB data. Below is a list of typical operating and cost inputs for each generic resource.

Thermal

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

Renewable

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 IV-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 ($000-yr) 2018$	$31,725	$19,058	$2,165	$1,342	$2,165
Capital Cost ($/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$	$37.98	$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	$15.26	$16.06	$5.91	$6.22	$8.06
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 IV-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 (%)	16.7%	50% declines to 30%		
Capacity Factor	50.0%	22.0%	18.0%	18.0%
Book life	25	25	25	25
Electric Transmission Delivery ($/kW)	500	200	0	0

Table IV-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 (%)	85
Equivalent Full Cycles per Year	250
Electric Transmission Delivery ($000) 2018$	0
Levelized $/kw-mo (All Fixed Costs) $2023	$18.18

Table IV-17: Levelized Capacity Costs by 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	$8.06	$6.22	$5.91	$16.06	$15.26			
2019	$8.22	$6.34	$6.02	$16.38	$15.56			
2020	$8.38	$6.47	$6.15	$16.71	$15.87	$20.04	$17.86	$22.94
2021	$8.55	$6.60	$6.27	$17.05	$16.19	$19.44	$16.81	$23.19
2022	$8.72	$6.73	$6.39	$17.39	$16.51	$18.82	$15.73	$23.45
2023	$8.89	$6.86	$6.52	$17.73	$16.85	$18.18	$14.62	$23.71
2024	$9.07	$7.00	$6.65	$18.09	$17.18	$17.52	$13.47	$23.97
2025	$9.25	$7.14	$6.78	$18.45	$17.53	$16.84	$12.30	$24.24
2026	$9.44	$7.28	$6.92	$18.82	$17.88	$16.63	$11.75	$24.51
2027	$9.63	$7.43	$7.06	$19.20	$18.23	$16.41	$11.18	$24.78
2028	$9.82	$7.58	$7.20	$19.58	$18.60	$16.19	$10.60	$25.06
2029	$10.02	$7.73	$7.34	$19.97	$18.97	$15.95	$10.00	$25.34
2030	$10.22	$7.88	$7.49	$20.37	$19.35	$15.71	$9.38	$25.62
2031	$10.42	$8.04	$7.64	$20.78	$19.74	$15.83	$9.38	$26.06
2032	$10.63	$8.20	$7.79	$21.19	$20.13	$15.94	$9.37	$26.50
2033	$10.84	$8.36	$7.95	$21.62	$20.53	$16.04	$9.36	$26.94
2034	$11.06	$8.53	$8.11	$22.05	$20.94	$16.15	$9.35	$27.40
2035	$11.28	$8.70	$8.27	$22.49	$21.36	$16.26	$9.33	$27.86
2036	$11.50	$8.88	$8.44	$22.94	$21.79	$16.36	$9.31	$28.32
2037	$11.73	$9.05	$8.60	$23.40	$22.23	$16.46	$9.28	$28.80
2038	$11.97	$9.24	$8.78	$23.87	$22.67	$16.56	$9.25	$29.28
2039	$12.21	$9.42	$8.95	$24.34	$23.12	$16.65	$9.21	$29.78
2040	$12.45	$9.61	$9.13	$24.83	$23.59	$16.74	$9.17	$30.27
2041	$12.70	$9.80	$9.31	$25.33	$24.06	$16.83	$9.13	$30.78
2042	$12.96	$10.00	$9.50	$25.83	$24.54	$16.76	$9.00	$30.97
2043	$13.22	$10.20	$9.69	$26.35	$25.03	$16.66	$8.85	$31.12
2044	$13.48	$10.40	$9.88	$26.88	$25.53	$16.55	$8.70	$31.25
2045	$13.75	$10.61	$10.08	$27.42	$26.04	$16.42	$8.53	$31.35
2046	$14.02	$10.82	$10.28	$27.96	$26.56	$16.26	$8.35	$31.41
2047	$14.30	$11.04	$10.49	$28.52	$27.09	$16.08	$8.16	$31.44
2048	$14.59	$11.26	$10.70	$29.09	$27.64	$15.88	$7.95	$31.42
2049	$14.88	$11.48	$10.91	$29.68	$28.19	$15.65	$7.73	$31.35
2050	$15.18	$11.71	$11.13	$30.27	$28.75	$15.39	$7.49	$31.23
2051	$15.48	$11.95	$11.35	$30.88	$29.33	$15.70	$7.64	$31.85
2052	$15.79	$12.19	$11.58	$31.49	$29.91	$16.01	$7.79	$32.49
2053	$16.11	$12.43	$11.81	$32.12	$30.51	$16.33	$7.95	$33.14
2054	$16.43	$12.68	$12.05	$32.76	$31.12	$16.66	$8.10	$33.80
2055	$16.76	$12.93	$12.29	$33.42	$31.75	$16.99	$8.27	$34.48
2056	$17.10	$13.19	$12.54	$34.09	$32.38	$17.33	$8.43	$35.17
2057	$17.44	$13.45	$12.79	$34.77	$33.03	$17.68	$8.60	$35.87

Table IV-18: Base Renewable Levelized Costs by Year

Levelized Costs by First Full Year of Operation $/MWh (LCOE)				
	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$28.29	$46.12	$61.16	$92.16
2021	$32.32	$48.12	$64.63	$94.44
2022	$36.53	$53.73	$74.07	$105.71
2023	$40.91	$53.81	$73.54	$102.31
2024	$36.03	$53.87	$72.96	$98.77
2025	$50.24	$53.93	$72.35	$95.07
2026	$50.28	$53.97	$71.70	$91.23
2027	$50.32	$53.99	$71.00	$87.23
2028	$50.36	$54.01	$70.26	$83.07
2029	$50.41	$54.00	$69.47	$78.75
2030	$50.46	$53.98	$68.64	$74.26
2031	$51.13	$54.60	$69.31	$74.25
2032	$51.81	$55.21	$69.97	$74.23
2033	$52.50	$55.83	$70.64	$74.17
2034	$53.19	$56.45	$71.31	$74.08
2035	$53.89	$57.07	$71.98	$73.96
2036	$54.60	$57.70	$72.65	$73.81
2037	$55.31	$58.32	$73.32	$73.62
2038	$56.03	$58.96	$73.98	$73.40
2039	$56.76	$59.59	$74.65	$73.15
2040	$57.49	$60.23	$75.31	$72.86
2041	$58.23	$60.94	$75.87	$73.52
2042	$58.98	$61.66	$76.42	$74.18
2043	$59.73	$62.38	$76.97	$74.84
2044	$60.49	$63.10	$77.51	$75.49
2045	$61.26	$63.83	$78.04	$76.15
2046	$62.03	$64.57	$78.56	$77.43
2047	$62.81	$65.31	$79.08	$78.73
2048	$63.60	$66.05	$79.58	$80.05
2049	$64.39	$66.80	$80.08	$81.40
2050	$65.19	$67.55	$80.56	$82.76
2051	$66.49	$68.90	$82.17	$84.42
2052	$67.82	$70.28	$83.81	$86.11
2053	$69.17	$71.69	$85.49	$87.83
2054	$70.56	$73.12	$87.20	$89.59
2055	$71.97	$74.58	$88.94	$91.38
2056	$73.41	$76.08	$90.72	$93.20
2057	$74.88	$77.60	$92.54	$95.07

**Distributed Solar costs represent at the meter values before grossing up for losses.*

Table IV-19: Low Renewable Levelized Costs by Year

Low Levelized Costs by First Full Year of Operation $/MWh (LCOE)				
	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$25.70	$40.39	$46.57	$80.57
2021	$28.96	$41.44	$44.77	$80.58
2022	$32.43	$45.30	$50.58	$87.80
2023	$36.12	$44.66	$49.46	$82.47
2024	$30.57	$43.99	$48.30	$76.99
2025	$44.15	$43.29	$47.11	$71.34
2026	$43.59	$42.57	$45.87	$65.52
2027	$43.05	$41.82	$44.59	$59.54
2028	$42.55	$41.04	$43.26	$53.38
2029	$42.07	$40.23	$41.89	$47.05
2030	$41.62	$39.40	$40.48	$40.54
2031	$42.10	$39.43	$40.22	$40.29
2032	$42.57	$39.45	$39.94	$40.02
2033	$43.05	$39.46	$39.63	$39.73
2034	$43.53	$39.45	$39.30	$39.41
2035	$44.01	$39.43	$38.95	$39.06
2036	$44.50	$39.59	$38.57	$38.69
2037	$44.98	$39.74	$38.16	$38.29
2038	$45.47	$39.88	$37.72	$37.86
2039	$45.96	$40.01	$37.25	$37.41
2040	$46.45	$40.14	$36.75	$36.92
2041	$46.94	$40.51	$37.10	$37.03
2042	$47.43	$40.89	$37.46	$37.13
2043	$47.92	$41.26	$37.81	$37.22
2044	$48.41	$41.63	$38.17	$37.31
2045	$48.90	$42.01	$37.15	$37.38
2046	$49.40	$42.47	$37.76	$37.91
2047	$49.89	$42.93	$38.38	$38.45
2048	$50.38	$43.40	$39.01	$39.00
2049	$50.88	$43.87	$39.65	$39.55
2050	$51.37	$44.34	$40.30	$40.11
2051	$52.40	$45.23	$41.10	$40.92
2052	$53.44	$46.13	$41.93	$41.74
2053	$54.51	$47.06	$42.76	$42.57
2054	$55.60	$48.00	$43.62	$43.42
2055	$56.71	$48.96	$44.49	$44.29
2056	$57.85	$49.94	$45.38	$45.18
2057	$59.01	$50.94	$46.29	$46.08

**Distributed Solar costs represent at the meter values before grossing up for losses.*

Table IV-20: High Renewable Levelized Costs by Year

High Levelized Costs by First Full Year of Operation $/MWh (LCOE)				
	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$31.34	$47.98	$68.45	$98.01
2021	$36.42	$50.93	$73.59	$105.38
2022	$41.69	$58.00	$86.61	$124.02
2023	$47.16	$59.16	$88.34	$126.50
2024	$43.38	$60.35	$90.11	$129.03
2025	$58.71	$61.55	$91.91	$131.61
2026	$59.88	$62.79	$93.75	$134.24
2027	$61.08	$64.04	$95.63	$136.93
2028	$62.30	$65.32	$97.54	$139.67
2029	$63.55	$66.63	$99.49	$142.46
2030	$64.82	$67.96	$101.48	$145.31
2031	$66.11	$69.32	$103.51	$148.22
2032	$67.43	$70.71	$105.58	$151.18
2033	$68.78	$72.12	$107.69	$154.20
2034	$70.16	$73.56	$109.85	$157.29
2035	$71.56	$75.03	$112.04	$160.43
2036	$72.99	$76.53	$114.28	$163.64
2037	$74.45	$78.07	$116.57	$166.91
2038	$75.94	$79.63	$118.90	$170.25
2039	$77.46	$81.22	$121.28	$173.66
2040	$79.01	$82.84	$123.70	$177.13
2041	$80.59	$84.50	$126.18	$180.67
2042	$82.20	$86.19	$128.70	$184.29
2043	$83.85	$87.91	$131.28	$187.97
2044	$85.52	$89.67	$133.90	$191.73
2045	$87.23	$91.47	$136.58	$195.57
2046	$88.98	$93.30	$139.31	$199.48
2047	$90.76	$95.16	$142.10	$203.47
2048	$92.57	$97.06	$144.94	$207.54
2049	$94.43	$99.01	$147.84	$211.69
2050	$96.31	$100.99	$150.79	$215.92
2051	$98.24	$103.01	$153.81	$220.24
2052	$100.20	$105.07	$156.89	$224.65
2053	$102.21	$107.17	$160.02	$229.14
2054	$104.25	$109.31	$163.23	$233.72
2055	$106.34	$111.50	$166.49	$238.40
2056	$108.46	$113.73	$169.82	$243.16
2057	$110.63	$116.00	$173.22	$248.03

**Distributed Solar costs represent at the meter values before grossing up for losses.*

V. Market Purchases and Sales Carbon Rate

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

Table IV-21: Market Purchase Carbon Rate

Market Purchase CO2 Rate																				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
lbs/MWh	1372	1307	1241	1176	1110	1045	1042	1039	1036	1034	1031	1018	1006	993	980	968	955	943	930	917
	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057
lbs/MWh	905	892	880	867	854	842	829	817	804	792	779	766	754	741	729	716	703	691	678	666

W. Sherco CC Size Alternatives

In its October 17, 2019 hearing in this docket, the Commission directed the Company to model different size alternatives for the planned Sherco CC. The Company developed three size alternatives – two smaller units and one larger unit – to test in sensitivity modeling. Cost and performance assumptions for each of these alternatives are detailed in Table IV-22 below.

Table IV-22: Sherco CC Alternatives

Thermal Generic Information				
Resource	**Sherco CC**	**7HA.01 1x1**	**7HA.02 1x1**	**7HA.02 2x1**
Technology	7H	7H	7H	7F
Location Type	Brownfield	Brownfield	Brownfield	Brownfield
Cooling Type	Wet	Wet	Wet	Wet
Book life	40	40	40	40
Nameplate Capacity (MW)	835	405	592	1202
Summer Peak Capacity (MW)	750	395	576	1170
Capital Cost ($000) 2018$	$837,068	$473,751	$629,206	$941,199
Electric Transmission Delivery ($000) 2018$	NA	NA	NA	NA
Ongoing Capital Expenditures ($000-yr) 2018$	$6,200	$4,190	$4,190	$8,775
Gas Demand ($000-yr) 2018$	$31,723	$31,723	$31,723	$31,723
Capital Cost ($/kW) 2018$	$1,002	$1,171	$1,064	$783
Electric Transmission Delivery ($/kW) 2018$	NA	NA	NA	NA
Ongoing Capital Expenditures ($/kW-yr) 2018$	$7.43	$10.35	$7.08	$7.30
Gas Demand ($/kW-yr) 2018$	$37.99	$78.41	$53.63	$26.38
Fixed O&M Cost ($000/yr) 2018$	$6,592	$7,150	$7,150	$8,647
Variable O&M Cost ($/MWh) 2018$	$1.04	$1.72	$1.72	$1.09
Levelized $/kw-mo (All Fixed Costs) $2018	$15.26	$18.36	$14.11	$10.95
Summer Heat Rate 100% Loading (btu/kWh)	6,359	6,322	6,208	6,452
Summer Heat Rate 75% Loading (btu/kWh)	6,547	6,419	6,257	6,403
Summer Heat Rate 50% Loading (btu/kWh)	6,985	6,681	6,516	6,812
Summer Heat Rate 25% Loading (btu/kWh)	8,004	7,553	7,388	7,479
Forced Outage Rate	3%	3%	3%	3%
Maintenance (weeks/yr)	5	5	5	5
CO2 Emissions (lbs/MMBtu)	118	118	118	118
SO2 Emissions (lbs/MWh)	0.00	0.00	0.00	0.00
NOx Emissions (lbs/MWh)	0.05	0.05	0.05	0.05
PM10 Emissions (lbs/MWh)	0.02	0.02	0.02	0.02
Mercury Emissions (lbs/MMWh)	0.00	0.00	0.00	0.00

V. RESOURCE OPTIONS

Our Strategist, and now EnCompass, modeling outcomes are highly dependent on inputs and assumptions. Appendix F6 of our initial filing discussed in more detail the resources included in our baseline, the resource options from which Strategist modeling could choose, and a non-exhaustive list of emerging technologies the Company is tracking and may explore further in order to meet our 2050 carbon-free energy goals. While many of these inputs and options have not changed since our initial filing in July 2019, there are some changes related to resource procurements and others to the types and attributes of resources our models available to the model to select for capacity expansion plans.

A. Baseline Resources – Updates to Existing Resources

In this section we outline the baseline resources available to the model and discuss any changes to these resources since our initial July 2019 Resource Plan filing. These include changes initiated by Commission decisions that were pending at the time of filing, project status changes, and newly approved resources. We also note that our approach to modeling baseline resources has changed since our initial filing. At that time, we included any resources that were existing, approved or pending approval with the Commission. Based on feedback received, we have included only existing and approved resources as of January 31, 2020. We implemented this modeling "lock-in" date to allow sufficient time to conduct Strategist and EnCompass modeling. To the extent projects were approved between February 1 and the June 30, 2020 Supplement filing date, we include a narrative description, and we believe including any resources approved in the intervening time period would not meaningfully change our Supplement Preferred Plan.

We provide a brief accounting of changes to our baseline resources and updated resource tables below.

1. Coal

There are no material changes to the magnitude of our coal-fired generation capacity since our initial filing in July. However, we received feedback from the Commission directing us to align the existing retirement date for Sherco Unit 3 with its current

2034 financial end of life date,[28] rather than the 2040 operational life used in our initial filing.

We also note that the Commission recently voted to approve, in Docket E-002/M-19-809, the Company dispatching our King and Sherco 2 units on a seasonal basis. We have incorporated seasonal dispatch into modeling, as it represents a significant operational change that impacts modeling outcomes. To reflect seasonal dispatch practices in modeling, we do not allow dispatch of King and Sherco 2 from March-May and September-November from the fall of 2020 to 2023. After 2023, Sherco 2 is retired and King is modeled on economic dispatch through its retirement date in a given scenario.

We summarize our existing coal units as applied in our modeling in Table V-1 below.

Table V-1: Baseline Coal Resources

Name of Unit or Contract	Type	Owned or Contracted (PPA)	Capacity (MW, max cap)	Existing Retirement/ Contract Expiration
Allen S King	Steam Turbine (ST)	Own	511	2036
Sherco 1	ST	Own	680	2026
Sherco 2	ST	Own	682	2023
Sherco 3[29]	ST	Own	517	2034

2. *Nuclear*

We have not made any changes to our nuclear units from our initial filing. For ease of reference, we have copied the Table from our July 2019 filing summarizing our nuclear units as applied in our modeling.[30]

[28] As reported in the Company's Annual Remaining Lives filing. The most recent filing can be found in Docket No. E002/D-19-161
[29] Note that this represents only the portion of Sherco 3 under our ownership.
[30] Note that we continue to test day-ahead flexible operations at our nuclear units, as discussed further in Attachment A Section VIII: Nuclear Updates. However, nuclear flexible dispatch is not currently factored into our modeling approach.

Table V-2: Baseline Nuclear Resources

Name of Unit or Contract	Type	Owned or Contracted (PPA)	Capacity (MW, max cap)	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

3. *Natural Gas and Oil*

The changes we made to our natural gas and oil units for this Supplement are based on Commission decisions, to align unit retirement dates with existing remaining/financial lives, and to reflect black start needs. In October 2019, the Commission denied the Company's request to acquire the Mankato Energy Center (MEC) units as Northern States Power-owned assets[31] and thus the units are, and will remain, merchant generators.[32] Accordingly, MEC Units 1 and 2 are in our baseline resources through their prevailing purchased power agreement (PPA) expiration dates of 2026 and 2039, respectively. Consistent with treatment of other PPAs, we do not assume either unit is re-contracted at the end of its PPA. We also modified the retirement dates for the Angus Anson units and Blue Lake 7 and 8 units to match their financial end of life dates approved in our last *Annual Remaining Lives* docket,[33] and the retirement date for French Island units to align with their current fuel contracts.

In our initial filing we noted that our black start units are aging, and we anticipated addressing this need in future filings. For this Supplement, we have taken steps to reflect future needs in modeling, by including placeholder capacity and associated life extension costs for black start resources in both Minnesota and Wisconsin, to 2030. We note that this approach does not equate to a proposal for specific unit life extension, rather is a placeholder for modeling until we complete our full analyses. In the table below we represent this placeholder capacity in a separate line item. In total

[31] *See* Docket No. IP6949, E002/PA-18-702. ORDER DENYING PETITION AND REQUIRING SUPPLEMENTAL MODELING. (December 19, 2019).
[32] The Commission approved the Company's request to acquire the units as merchant affiliate assets in Docket No. E002/AI/19-622. However, the Company has since agreed to sell the MEC facility to Southwest Generation. The sale is expected to close in the third quarter of 2020. The units will remain under contract to sell to NSP through their current contract dates. *See* Docket No. E002/AI-19-622 LETTER – MANKATO ENERGY CENTER I AND II AFFILIATED INTEREST REQUEST (April 6, 2020).
[33] *See* Docket No. E,G002/D-19-161.

this placeholder capacity represents just over 600 MW of max capacity and an unforced capacity of approximately 430 MW. Further discussion on our black start resources and how they are handled in modeling is available in Attachment A Section VII: Black Start.[34]

Finally, we note that the planned Sherco CC is also included in our baseline modeling, given that the unit is provided for via Minnesota statute. [35] This unit is modeled as a 2-by-1 unit, adding 728 MW of accredited capacity (corresponding to 835 MW installed capacity), starting in 2027 after the current Sherco 1 coal unit retires. Per the Commission's direction, we have also conducted sensitivity modeling that tests alternate Sherco CC sizes to determine the economic impact of a differently sized unit. These sensitivities are outlined further below in Section B.3.

We summarize each of the units as applied in our modeling in the below Table.

[34] Note that some information regarding black start units and plans is subject to trade secret protection; this information is consolidated in one section to reduce the number of redactions necessary in this filing.
[35] *See* Minnesota Session Laws-2017 Ch. 5. H.F. No. 113.

Table V-3: Baseline Natural Gas and Oil Resources[36]

Name of Unit or Contract	Type	Owned or Contracted (PPA)	Capacity (MW, max cap)	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 Unit 1	CC	PPA	375	2026
Mankato Energy Center Unit 2	CC	PPA	345	2038
LSP – Cottage Grove	CC	PPA	245	2027
Angus Anson 2-3	CT	Own	218	2040
Angus Anson 4	CT	Own	168	2044
Black Dog 6	CT	Own	232	2058
Blue Lake 7,8	CT	Own	351	2044
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	2030
Wheaton 6	Oil	Own	70	2025
Sherco CC	*CC*	*Own*	*835*	*No retirement date assigned*
Black Start – Minnesota and Wisconsin	*CT*	*Own*	*Approx. 620 MW*	*Extended from current end of lives to 2030*

4. *Biomass*

The Company owns and operates, and maintains PPAs for, various biomass facilities. We include in this category refuse-derived fuel (RDF), landfill (LND) and digester (DIGT) resources as well. Since our initial filing, the 12 MW PPA with KODA Resources and the 0.5 MW PPA with Heller Dairy have expired and were removed

[36] Units in italics represent capacity that is included in the baseline, but either not yet online (Sherco CC) or represent placeholder capacity (black start unit extension placeholder).

from the resource baseline. Additionally, Diamond Dairy terminated its 0.4 MW PPA early in 2019 and was removed from the baseline resources. We also modified French Island 1 and 2 retirement dates for alignment with fuel contracts and retirement dates for units 3 and 4. Finally, we have extended the PPA for the Waste Management (WM) Renewable Energy facility listed below for an additional two years beyond its previous expiration date in 2020; however this capacity is not factored into modeling because the PPA extension occurred after the January 31 resource lock-in date.

We summarize our modeled biomass resources below.

Table V-4: Baseline Biomass Resources

Name of Unit or Contract	Type	Owned or Contracted (PPA)	Capacity (MW, max cap)	Retirement/ Contract Expiration
Bayfront 5,6	Bio	Own	26	2035
French Island 1,2	Bio	Own	15	2030
Red Wing 1,2	Bio	Own	18	2027
Wilmarth 1,2	Bio	Own	17	2027
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
Greenwhey	DIGT	PPA	3	2023

5. *Hydroelectric*

The Company owns, operates and maintains PPAs for hydropower resources, with the majority of our current capacity coming from PPAs with Manitoba Hydro. The only change from our initial filing is the removal of two small hydro PPAs – Neshonoc and Rapidan. Both of these PPAs have expired, and new agreements were not yet finalized as of the end of January 2020. As in our initial filing, we also include in modeling our diversity agreement with Manitoba Hydro, which is not reflected in the table below. This agreement provides the NSP System with 342 MW of accredited capacity (350 MW max capacity) in the summer only – and Manitoba Hydro receives 350 MW capacity in the winter only – through 2025.

We summarize the hydropower resources as applied in our modeling in the below Table.

Table V-5: Baseline Hydroelectric Resources

Name of Contract or Unit	Type	Owned or Contracted (PPA)	Capacity (MW, max cap)	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
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	375	2025
Manitoba Hydro	Hydro	PPA	125	2025 (2021 start)

6. *Wind*

Most of the wind resources listed in our initial filing are unchanged, with the exception of Lake Benton I and the Crowned Ridge Projects. Lake Benton II's PPA expired in 2019 and thus was removed from modeling; however, the project was repowered and re-contracted as Lake Benton Repower, which is included below. Crowned Ridge I and II were originally approved by the Commission in Docket No. E002/M-16-777 as two 300 MW projects; energy from Crowned Ridge I would be procured via PPA, and Crowned Ridge II would be acquired by the Company upon its completion. In August 2019, we notified the Commission that the project's Seller intended to reduce the size of the projects by 100 MW each as a result of transmission interconnection costs assigned to a portion of the project.[37] The Company and Seller amended both contracts to reflect this change, and we filed these amendments with the Commission in December 2019.[38] Accordingly, we have reduced the size of

[37] *See* In the Matter of the Petition of Xcel Energy for Approval of the Acquisition of Wind Generation from the Company's 2016-2030 Integrated Resource Plan, Docket No. E002/M-16-777, XCEL ENERGY LETTER: CROWNED RIDGE UPDATE (August 30, 2019).
[38] *See* In the Matter of the Petition of Xcel Energy for Approval of the Acquisition of Wind Generation from the Company's 2016-2030 Integrated Resource Plan, Docket No. E002/M-16-777, PURCHASED POWER AGREEMENT AND PURCHASE AND SALE AGREEMENT AMENDMENTS. (December 20, 2019)

Crowned Ridge I and II to 200 MW each in our modeling to reflect the current contracts.[39]

As of our January 31, 2020 resource assumptions lock-in, there were two proposed acquisitions yet pending.

- *Deuel Harvest PPA.* This project, for 100 MW of wind coming online by the end of 2021 and expiring in 2036, was approved by the Commission in February 2020.[40] The Company will use this PPA to serve the Company's planned and approved Renewable*Connect expansion.[41]
- *Mower County Wind.* The Company has proposed to acquire a repowered 98.9 MW Mower County Wind facility.[42] The existing PPA for the facility runs through 2026. If the acquisition is approved, we would expect the repowered facility to come online at the end of 2020 and operate until 2045. The Mower County facility was modeled in accordance with the existing PPA in our analyses.

We summarize the wind resources included in our baseline modeling below.

[39] As noted in our March 3, 2020 Reply Comments in Docket No. E002/M-16-777.
[40] *See* Docket No. E002/M-19-268 ORDER – IN THE MATTER OF XCEL ENERGY'S PETITION FOR APPROVAL OF A WIND ENERGY PURCHASE AGREEMENT WITH INVENERGY WIND ENERGY DEVELOPMENT, LLC. (February 12, 2020).
[41] Approved in Docket No. E002/M-19-33.
[42] *See* Docket No. E002/PA-19-553.

Table V-6: Baseline Wind Resources

Name of Contract or Unit	Type	Owned or Contracted (PPA)	Capacity (MW, max cap)	Retirement/ Contract Expiration
Big Blue	Wind	PPA	36	2032
Chanarambie	Wind	PPA	86	2023
Community Wind North	Wind	Own	26	2044
Fenton	Wind	PPA	206	2032
McNeilus Group	Wind	PPA	37	2028
Jeffers	Wind	Own	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
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	200	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	200	2044
Small Wind[43]	Wind	PPA	270	Various

[43] Includes PPAs of 20 MW or less; this number was adjusted from the initial filing to correct a counting error.

7. *Solar*

The utility-scale solar units included in our modeling baseline have not changed since our initial filing. We have however, updated our distributed solar (DG Solar) and Community Solar Garden totals to include additional capacity that was not yet accounted in our initial filing. We note that one project was pending approval as of the January 31 lock-in date and is therefore not included in our baseline modeling. Elk Creek Solar is an 80 MW project proposed to come online by the end of 2021 and expire in 2041.[44] We plan to use this PPA to serve our approved Renewable*Connect expansion.[45]

We summarize the solar resources included in our baseline modeling below.

Table V-7: Baseline Solar Resources

Name of Contract or Unit	Type	Owned or Contracted (PPA)	Capacity (MW, max cap)	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
Aurora	PV	PPA	99	2036
Marshall	PV	PPA	62	2042
North Star	PV	PPA	99	2041
DG Solar[46]	PV		80	Various
Community Solar Garden	PV	PPA	658	Various

B. Generic Future Resource Options

Many of the generic future resource options made available for the model to select in capacity expansion modeling remain unchanged from our initial filing. However, we have made certain changes in response to feedback from the Commission and stakeholders. These changes broadly fall along two lines: 1) updates to our approach for resources included in capacity expansion modeling; and 2) additional resource options developed to test in sensitivity modeling.

[44] *See* Docket No. E002/M-19-558.
[45] Approved in Docket No. E002/M-19-33.
[46] Includes Solar*Rewards, Made in MN Solar, and Other RDF Solar not accounted for in other sections above.

First, we have updated certain assumptions related to generic resources that are available to fill identified energy and capacity needs in modeling, as follows:

- *Cost estimates and accredited capacity for renewable and storage resources.* We have updated cost trajectories to utilize the 2019 version of the NREL ATB. As a result of this update, solar, wind, and storage prices have declined across the modeling period. We further detail these cost assumptions in Attachment A Section IV and discuss below. We have also updated accredited capacity assumptions for wind and solar resources, as described in Section II: Modeling Framework and Results and discussed further below.
- *Streamlining natural gas CT plant options.* For this Supplement, in order to streamline the modeling process, we conducted pre-screening to narrow the available generic CT options from considering multiple brownfield and greenfield configurations to one single generic greenfield option.

Second, we have also incorporated the Commission's feedback and developed specific hybrid renewable-plus-storage resource options, including wind-plus-storage and solar-plus-storage. We use these new resource options in our Preferred plan sensitivities to assess whether such a paired resource would be selected as cost-effective.

Finally, we developed cost estimates to test different sizes of a combined-cycle unit (CC) located at the Sherco site in the context of our Supplement Preferred Plan. These sensitivity model runs help us examine the economic impact of sizing the unit larger or smaller relative to the size included in our baseline modeling.

1. Changes to Generic Resource Options

- *Wind:* Our generic wind resource option is sized at 750 MW nameplate capacity, which corresponds to approximately 125 MW of accredited capacity). Whereas in our initial filing, wind resources were assigned an ELCC of 15.6 percent, in line with the most recent MISO average values available at the time, we modified our approach to using even more recently available ELCC value for Zone 1, which is 16.7 percent. This modification better reflects higher production and average capacity credits assigned to existing wind resources in our region, relative to other parts of MISO. Wind costs are based on 2019 ATB forecasts for wind Technology Resource Group (TRG) 2,[47] adjusted for tax credit values in relevant years, and estimated transmission interconnection costs associated with greenfield facilities. In our initial filing we assumed that a greenfield wind project would be subject to $400/kW transmission interconnection costs. Since then, it has become apparent that transmission constraints in the MISO West region are increasingly severe, such that the average identified upgrade cost in some studies is upwards of $2,000/kW. In order to account for these near-term constraints in our modeling, we have not made wind available to the model to select prior to 2026 in our baseload scenario modeling. Starting in 2026 we apply a $500/kW interconnection cost to generic wind resources.

- *Utility-scale Solar:* Our generic solar option is sized at 500 MW on a nameplate basis. Accredited capacity is dependent upon the declining Effective Load Carrying Capability assumption used in modeling for solar. In the first several years of the analysis period, we use the current 50 percent ELCC, corresponding to a 250 MW accredited capacity for generic new solar. By 2033, however, the modeled ELCC declines to 30 percent, which would correspond to 150 MW of accredited solar capacity. This assumption is consistent with those MISO uses in their latest MTEP Futures modeling. For solar cost assumptions, we have used updated 2019 ATB forecasts, adjusted for tax credit values in relevant years and estimated transmission interconnection costs. In light of increasing transmission constraints, we have assumed higher solar interconnection costs in this Supplement – increasing from $140/kW to $200/kW. We believe increasing the interconnection cost for solar resources is a reasonable approach based on the trends observed in MISO's most recent interconnection studies.

- *Natural Gas CT:* As noted above, we streamlined the CT unit options the model could select for the purposes of this Supplement. To do so, we conducted prescreening that narrowed the options made available to modeling to only one 374 MW nameplate (321 MW accredited) greenfield option and eliminated brownfield options previously available. The cost and configuration assumptions included for the greenfield unit remain unchanged from our initial filing.

- *Natural Gas CC:* Our approach to modeling generic CCs has not changed in this Supplement. We made one greenfield CC option available to the model, of

[47] Note that in our initial filing we used TRG 1 costs for wind resources; however, we believe the capacity factors in TRG 2 are likely better aligned with remaining available sites in our region for greenfield wind, given already substantial build out.

approximately 900 MW (856 MW accredited), with cost assumptions developed utilizing external consultant analyses.

- *Battery Energy Storage:* As in our initial filing, we have made a generic stand-alone four-hour battery storage option an available option in our modeling. The generic unit continues to be sized at 321 MW. However, whereas previously our resource cost assumptions were based on bids received in our Public Service Company of Colorado operating company affiliate's 2017 all-source solicitation and adjusted for an assumed technology improvement trajectory, for this update we have used the 2019 ATB cost forecasts for lithium-ion battery storage resources.

- *Demand Response:* Like our initial modeling, we modeled incremental demand response (DR) resources in "Bundles" of potential measures, informed by the Brattle Group's *Demand Response Potential Study*.[48] For the purposes of Supplement modeling, we updated the bundles to account for the passage of time and observed historical performance in certain programs included in the bundles. In the previous modeling the incremental first Bundle was added into our proposed Preferred Plan after the capacity expansion runs optimized in the model. However, for this Supplement, the first Bundle is included in our baseline resource modeling, and it continues to achieve the Commission's targeted 400 MW of incremental DR by 2023[49]. Our updated five-year action plan for DR resources is included in Attachment A Section XIV.

- *Energy Efficiency:* Consistent with our initial filing, we utilized the statewide *Minnesota Energy Efficiency Potential Study* (2020-2029) to develop three Bundles that would be available for the model to select as supply-side resources. These Bundles have not changed since our initial filing, and we have included the first two Bundles in our portfolio modeling.

2. *New Hybrid Renewable-Plus-Storage Resource Options*

As noted above, the resources available to our capacity expansion models to select included standalone wind, solar and storage individually. However, there are potential combinations of these resources; wind or solar paired with storage, that provide an opportunity for variable renewables to be more flexible. Like many of our peer utilities, we anticipate that there will be opportunities to co-locate storage and

[48] Provided as Appendix G2 to our initial filing in this docket.
[49] We note that our modeling for this Supplement does not incorporate potential changes to energy demand or DR adoption as a result of the ongoing COVID-19 health crisis and accompanying economic impacts. We do not yet know the full extent of these shifts but will continue to evaluate them in the coming months.

renewable resources in the future in a way that reduces costs for customers. To capture this possibility, and in response to Commission feedback, we added a sensitivity analysis that examines the potential for renewable-plus-storage resources to economically displace resources included in our initial baseload scenarios.

For both hybrid units – wind-plus-storage or solar-plus-storage – we assume the energy storage resource is a 125 MW four-hour lithium ion battery. The solar and wind components are sized the same as the standard generic options. Capacity accreditation values for the hybrid units remain separately counted. For example, we assume the wind portion of a hybrid wind-plus-storage unit is assigned a 16.7 percent ELCC, while the storage portion receives 100 percent ELCC. The hybrid unit's cost is assumed to be equal to the LCOE of a standalone wind unit, plus the levelized $/kW cost of the battery. We do not assign incremental transmission costs to the storage addition. We follow the same process for a hybrid solar-plus-storage resource; however, such a resource qualifies to receive the solar Investment Tax Credit (ITC), per the year it is placed into service, and our levelized cost assumptions reflect this benefit.[50] Additional detail on our hybrid-resource cost assumptions is available in Attachment A Section IV.

3. *Sherco CC Size Sensitivities*

Per the November 2019 Order requiring additional modeling,[51] we have developed sensitivities to test the effect of different Sherco CC sizes on the cost effectiveness of our Supplement Preferred Plan. To do so we developed cost and operational assumptions around three size options, both larger and smaller than the 835 nameplate (and 750 net summer) MW size option included in our scenario modeling. Testing a breadth of options in our sensitivity analysis results in a better assessment of the directional impact on our overall system costs.

As discussed in our initial filing, we developed assumptions for the baseline Sherco CC assumptions using a combination of internal estimates and available technology information collected from external sources. The Sherco CC assumptions included in our Supplement's baseline modeling are substantially the same as the ones we used in in our initial modeling.[52] Based on further discussions with vendors and internal

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[50] Equal to 10 percent of the total value of the system, for systems beginning construction after 2021.
[51] *See* Docket No. E002/RP-19-368. ORDER SUSPENDING PROCEDURAL SCHEDULE AND REQUIRING ADDITIONAL FILINGS (November 12, 2019) at Order Point 2.B.
[52] We have applied limited changes to reflect evolving gas supply estimates; whereas we had previously assumed an annual gas demand charge as well as a contribution in aid of construction (CIAC) charge, we now have rolled all assumed gas supply costs into an annual demand charge of approximately $41 million.

analysis, we developed three alternately sized options to test in sensitivity analyses. We note that these options are only representative; actual configurations and costs depend upon vendor and site-specific parameters that would be determined in project development.

Table V-8 contains a summary of the three size options we tested in our Sherco CC sensitivities. Additional detailed information is available in Attachment A Section IV.

Table V-8: Summary of Sherco CC Size Sensitivity Options

Analysis Option	Size (MW, Nameplate)	Size (MW, Net Summer)	Configuration	All-in Cost ($/nameplate MW)
Baseline	835	750	2 CTs, 1 ST (2x1) Wet Cooled No Duct Firing	$1,002,000
Small – 1	405	395	1 CT, 1 ST (1x1) Wet Cooled No Duct Firing	$1,171,000
Small – 2	592	577	1 CT, 1 ST (1x1) Wet Cooled No Duct Firing	$1,064,000
Large – 1	1,077	1,046	2 CTs, 1 ST (2x1) Wet Cooled No Duct Firing	$874,000

VI. RESOURCE ATTRIBUTES

Integrated Resource Planning is intended to identify the size, type, and timing of resources we will need on our system in the future and has traditionally been largely focused on an examination of capacity adequacy. One objective inherent in this process, although not explicitly stated, is consideration of resource *attributes* and the importance of aligning the types of resources we need for the reliability of our system and broader grid. While we model our capacity expansion plans based on specific technology types' cost and operational characteristics, we also must look across resource types to ensure a balanced portfolio that provides appropriate capacity, energy, and flexibility attributes in aggregate.

Examining a portfolio's resource attributes is becoming increasingly important as capacity adequacy decouples from other reliability attributes. Variable resources make up an increasing share of our future generation mix; these resources provide carbon emission avoidance benefits to our system, but also represent a significant shift in operating characteristics relative to the legacy grid. Traditional thermal and some hydropower resources are considered "firm," such that they can supply electricity reliably, on demand, for long durations. Many also provide ancillary grid stability and strength benefits that help the system respond instantaneously to – and ride through – variance in frequency or voltages. Some are also designed to provide flexibility, meaning that they can be ramped up or down relatively quickly in response to changes in customer demand. Variable renewables like wind and solar have introduced new opportunities to provide zero-carbon energy, at low or zero-marginal cost. As such, they are generally given preference in a grid operator's dispatch order. However, as they are variable rather than firm, other resources on the grid must be able to accommodate fluctuation in their output as it occurs and ensure energy and capacity adequacy every hour of every day.

Ultimately, each type of resource contributes different benefits, but in combination, the same resource attributes the grid has had in the past must be ensured going forward to guarantee we can meet customers' electricity needs. As variable renewables increase as a share of the total energy and capacity available on the grid, the grid becomes more complex, with more variations in net load for which other resources must be prepared to provide. Our resource planning models help assess these needs, but as the grid's complexity increases, we need to employ additional modeling and analyses to adequately plan for a clean, reliable future. Capacity expansion models like Strategist have been useful to identify capacity adequacy, as they integrate resource adequacy (RA) guidance we receive from MISO. However, our traditional Strategist modeling – which relies on load duration curves to evaluate whether a portfolio will be capacity and energy sufficient in a given year – cannot adequately capture this increasing variability, and thus will no longer be sufficient to ensure our resource plans will meet customer needs in every hour of every day. As such, we have added the EnCompass hourly production cost modeling capabilities to our suite of portfolio evaluation tools for this Supplement and will rely primarily on EnCompass for our Resource Plan modeling going forward. Production cost modeling tools such as EnCompass include features such as hourly chronological dispatch analysis, which help us evaluate potential energy adequacy and flexibility shortfalls on an intraday basis, across a full analysis year. It provides the more granular analysis necessary to uncover potential reliability challenges associated with transitioning our system to include, and rely on, more variable resources.

As more emitting thermal generation retires from our grid and is replaced with variable renewable and fast-response – but use-limited resources – the tools and measures we use to conduct long-term resource planning will continue to evolve. In fact, there continue to be new approaches developed to value these attributes in planning processes. The Company will continue to evaluate the best ways to incorporate resource attributes into its planning processes in the future, as we navigate the transition to achieve 100 percent zero-carbon generation by 2050.

A. Resource Attributes' Intersection with Resource Types

As discussed above, our resource planning process primarily evaluates the size, type, and timing of resource additions we need to serve customers reliably in the future. Our baseline resources – those already on our system – are modeled using known operating characteristics. For future resource additions, we model individual generic resource options that our capacity expansion model can select – whether wind, solar, natural gas combustion turbines, battery storage, or others – in order to appropriately capture different technology costs and operating characteristics of each resource.

Historically, the grid consisted primarily of traditional thermal and hydropower sources, and the attributes of these resources could be relatively easily matched to grid needs. Coal and nuclear resources provided a grid resilience "backbone" attributable to their large rotating generators that help maintain important inertia, stability, and strength for the grid. To the extent the grid needed flexibility for changing loads, some coal units and natural gas and fuel oil peaking plants could ramp up or down to meet that need. These resources all have secure fuel supplies, either through firm energy contracts, on-site storage, or other long-duration refueling planning.

The grid is now transitioning away from many of these traditional resources. Thermal plants are retiring and variable and use-limited resources such as wind, solar and battery energy storage are increasing. This means that the quantity of resources that have traditionally provided grid resilience attributes are decreasing, and the quantity of resources that require the grid to operate more flexibly are increasing. Overall, grid operators must ensure that, as the mix of resources on the grid continues to evolve, all the necessary resource attributes that ensure a reliable supply and delivery of electricity to customers are still present.

Below we map these attributes against the resources that can provide them and discuss each attribute.

Figure VI-1: Resource Attributes Mapped to Resource Types

		Resource Types	**Firm Traditional – Baseload**	**Firm Traditional – Intermediate or Peaking**	**Variable Renewables**	**Fast-Burst Balancing**	**Transmission Solutions**
Resource Attributes	**Response Duration & (Frequency of Need)**	***Examples***	*Coal, Nuclear, Biomass, Run-of-river Hydro*	*CC, CT*	*Standalone Wind, Solar*	*DR, Standalone Battery Storage*	*Synchronous condensers, HVDC, Static Var Compensators*
Essential Reliability Services	Minutes – Milliseconds (Continuous)	*Spinning reserve, inertial response, frequency regulation, voltage control*	Nuclear / Non-nuclear				
Flexibility	Minutes – Hours (Daily)	*Ramp rates, cycling, minimum runtime*					
Energy Availability	Hourly - Multiday (Continuous)	*Long duration availability, secure fuel supply*					
Black Start	Minutes – Hours (Infrequent, emergency only)	*Starts and runs on zero load, secure fuel supply*	Nuclear / Non-nuclear				

1. *Essential Reliability Services – System Strength and Stability*

System strength and system stability are two related – but distinct – aspects of essential reliability services that work together to ensure the grid can detect and respond to periodic disturbances that may otherwise cause outages or other voltage disturbances. System strength refers to the grid's ability to maintain stable voltages, and for grid control systems to be able to detect differences between normal and abnormal conditions in the event of a grid disturbance. The stronger a system is, the more quickly and capably it can respond to – and mitigate – a destabilizing event. Controlling voltages on the grid at all locations, at all times, to acceptable levels is essential for power quality and reliability.

System stability refers to the grid's ability to respond to these disturbances to maintain balance; it includes factors such as frequency regulation, spinning reserve, and inertial response capabilities. Frequency regulation refers to how grid assets respond to rapid changes continuously occurring on the grid and ensure that the energy produced on the system precisely matches customer usage at all times. Spinning reserve is a generator's capacity that is available but remains available/unloaded, so that it can be used to provide extra generation if needed to meet customer needs. Inertia is an attribute of generators with large, spinning rotors that helps the system "ride through" disturbances to the grid that, without inertia, would impact reliability.

In general, firm traditional resources – such as conventional thermal and hydroelectric generation – can and have provided a wide range of essential reliability services. For example, they provide system strengthening voltage control because they are synchronous generators, with excitation systems controlled by Automatic Voltage Regulators. These are essential for the generators' own stability and also enable the generators to provide full reactive range for voltage control, down to their minimum generation limits. Many can also provide a broad range of system stability services, via governor controls systems that allow primary frequency response up to their rating, and – as a dispatchable resource – can be operated with headroom for providing spinning reserve. One exception is nuclear power, which does not provide fast response services, but is an excellent source of inertial response.

Variable renewable resources can provide some of these essential reliability services through pitch controls, inverter-based voltage control, and curtailment. Their inverters can provide fast voltage/reactive control capabilities over a wide range of active power conditions, although not at the same level as synchronous resources. However, these resources are also typically grid-following, which means they have to rely on a reference signal from the grid to operate reliably through a disturbance; if a voltage event disrupts this reference signal, the resource may not be able to respond effectively. Further, variable renewables sometimes have technical potential to provide essential reliability services, but the way they are operated and dispatched make them less practical sources. For example, variable resources like wind and solar typically run at full output, for economic and environmental reasons. Thus, they can be curtailed from normal operating conditions to respond to over-frequency events; but they are rarely intentionally operated under full capacity for long durations in order to provide spinning reserves or respond to under-frequency events.

Fast-burst balancing resources – such as DR or standalone battery storage – are both technically capable of providing various essential reliability services, but their availability to do so varies. Battery energy storage can provide extremely fast reactive power and voltage control services, but it is duration-limited; depending on the size and configuration of the battery and state of charge, it may not be able to provide these services for long periods of time. DR resources have traditionally controlled only real power usage and have not provided direct voltage and reactive power control. Battery energy storage is well suited to carry spinning reserve and provide primary frequency response if the battery's state of charge at a given time allows, whereas DR resources are not typically available to provide primary frequency response or spinning reserve.

Finally, transmission solutions are well-positioned to provide essential reliability services. Flexible Alternating Current Transmission System (FACTS) devices are designed to enhance the system's controllability and increase power transfer capability, by enabling reactive power to be absorbed or injected into the grid as needed to maintain reliability. These include such technologies as Static VAR Compensators, Static Synchronous Compensators, advanced inverters and other technologies. Traditional AC transmission components and High Voltage Direct Current (HVDC) infrastructure – while not providing essential reliability services directly – assist in connecting generation and supportive transmission resources that can provide them to the location of need on the system.

2. *Flexibility*

Flexibility refers to the grid's ability to maintain balance between energy supply and customer demand. Distinct from the reliability value of frequency response or voltage control – which ensure grid stability and strength – flexibility ensures that there is sufficient capacity with the right capabilities to ramp up or down with fluctuations in net demand. These changes could be either a result of unexpected or cyclical increases in energy demand from customers, or changes in renewable resource availability. Key measures of flexibility include a resource's start time, ramp rate, energy availability duration, and its ability to cycle.

As its name implies, traditional baseload generation has not historically been well suited to provide grid flexibility; these plants are intended to run at relatively high output for long durations, and do not typically load follow or ramp in response to net demand changes. That said, as variable renewable adoption on the grid has increased, we have made and continue to make adjustments to these resources to make them more flexible. For example, we are beginning to implement flexible nuclear operations procedures that may allow us to ramp generation at these units up or down at least 10-15 percent, with day-ahead scheduling. Economic dispatch and seasonal operations for coal plants – both of which we are pursuing for our Minnesota coal plants – can also be considered a type of flexibility.[53]

Intermediate and peaking resources are some of the best positioned resources to provide flexibility to the system. Intermediate plants such as combined cycles (CC) are designed to load follow, within certain boundaries, in order to adjust to net load on the system over the course of a day. However, they are not typically designed to ramp quickly or start and stop more frequently; this is where peaking units such as combustion turbines (CT) fill a gap. CTs are intended to be able to meet evening load ramps, when demand typically increases, as well as start relatively quickly if the grid operator foresees a decline in variable renewable resources.

Variable renewables themselves can provide some flexibility services, if equipped with enabling technology – such as advanced inverters – or during periods of resource availability, with curtailment operations. That said, curtailment provisions in contracts and foregone clean generation typically make operating variable renewables in this manner less favorable. In other words, to keep the cleanest, lowest marginal cost resources operating as much as possible, grid operators have tended to use intermediate and peaking resources to fill-in around clean baseload and variable renewables.

Fast-burst balancing resources, such as DR and battery energy storage, can also meet a range of flexibility needs. Their ability to respond quickly to calls for load shifting needs can help address ramping and cycling needs, especially for relatively short duration events. As discussed above, battery energy storage can also help mitigate renewable resource variability when paired with wind or solar generation. As battery costs continue to decline, we would expect to see more paired resources combining

[53] Our modeling reflects seasonal dispatch for King and Sherco 2 from Fall 2020-2023. After that time Sherco 2 retires and King continues to operate on an economic basis through its retirement date. Flexible nuclear operations is not yet integrated into our modeling as we work to better understand the parameters under which our units may perform this function. We discuss flexible nuclear operations further in Attachment A Section VIII.

the clean energy benefits of variable renewables with the balancing benefits of energy storage.

We note that transmission solutions also play an enabling role in energy flexibility, despite not providing it directly. For example, HVDC ties across broader regions increases a system's import and export capabilities and improves access to benefits from resource and geographic diversity. Particularly for variable renewables, increasing geographic diversity can reduce the effects of weather correlation; in other words, access to resources across broader areas makes it less likely that a localized renewable drought will result in energy shortfalls for that system's customers. That said, weather correlation can and does happen across broad regions, and thus transmission solutions are not alone sufficient to mitigate variability.

3. Energy Availability

Having sufficient energy available to meet demand across every hour of every day throughout the year is another fundamental element of reliability. The extent to which a given resource's capacity may be unavailable for unplanned reasons impacts the contribution of that resource to meeting our customers' energy needs. Planning and modeling must examine not only *average* availability, but also the extent to which underlying correlations with climatological or other factors result in higher unavailability or outage rates during peak load or other higher-risk periods. A resource's availability is driven by both fuel and equipment availability considerations, but we focus on fuel availability here.

The certainty of fuel availability – whether a plant will have fuel on site to produce electricity when needed – differs for different resource types. Traditional firm baseload resources are generally the most fuel-secure, as they have physical fuel resources on site. Coal and nuclear plants, for example, typically have a certain number of days-worth of on-site fuel storage either in fuel storage yards (for coal) or within the plant itself (nuclear fuel rods). Natural gas plants may have on-site storage, but, more typically, plant operators ensure fuel delivery through firm supply contracts. Firm contracts mitigate fuel availability issues, as long as the natural gas transmission and delivery system do not face unexpected operational challenges.

Other resource types face fuel availability limitations. Variable renewables are dependent on climatological conditions, which can be forecasted within certain margins of error, but these forecasts do not provide the same level of fuel security as a plant with physical fuel on-site or guaranteed via firm contracts. Further, plant operators are limited in their ability to control variable renewable fuel sources. Thus, other resources on the grid must be prepared to fill in gaps when they are not producing. At scale, this absence of on-demand fuel availability can create ramping challenges regardless of whether changes in availability were forecast.

Fast-burst resources can vary in their fuel availability, either based on state of charge at a given time (for battery energy storage) or customers' willingness to respond to calls to reduce their demand (DR); further, these resources are duration limited. Typical battery energy storage facilities using current technology can provide up to four hours of discharge at its given rating, if the battery started at a full state of charge. DR calls generally have duration and frequency parameters and are additionally subject to customer discretion. That said, battery storage holds particular promise for addressing some of the fuel availability challenges associated with variable renewables, as a battery can charge during periods of renewable overgeneration and discharge when the resource is unavailable.

4. *Black Start*

Finally, black start capability is a rarely needed – but essential – grid attribute. Black start capability refers to whether the grid has specialized resources that can "jumpstart" the grid from a partial or complete outage.[54] These resources require a secure fuel source, must be able to start without external electrical support from the grid and run unloaded for relatively long periods of time. They must be able to provide both real and reactive power, so that the transmission operator can use them to balance bringing incremental loads onto the system while providing energy to start other non-black start capable grid resources. We discuss our black start resources further in Attachment A Section VII.

There are few resource types well positioned to provide black start service. Black start units are typically firm traditional resources because, when equipped with certain controls, they are capable of meeting the necessary requirements discussed above. Variable renewable resources cannot provide this service because they do not have secure fuel sources and their power outputs are not easily controlled in order to balance with incremental load. While battery energy storage is theoretically capable of operating under these conditions, such units only have secure fuel sources insofar as they are charged at the time of a grid failure. Black start resources must be capable of running for longer periods of time than typical battery energy storage systems are configured to operate, especially in the event a subsequently-started generator trips

[54] Note that black start capabilities are distinct from system restoration more broadly. This section refers specifically to the ability of a generator to start from black, on demand.

back offline, and the process must be restarted; a rather common occurrence during a black start event. To reliably provide black start service, a battery would need to be capable of 24 hours or more of discharge, which is prohibitively expensive given current technology. We also note that the amount of battery capacity designated for black start service would likely not be able to participate in other commercial market opportunities – such as ancillary service markets – rather, would always have to maintain a full state of charge, per black start capable fuel security requirements. As a result, the cost of such a battery is not likely to be effectively mitigated by its opportunity to provide system services under normal operations.

B. Resource Attribute Evaluation in Resource Planning Models

The Company relies on planning models to determine the combination of resources that will best serve our system's needs, including their ability to meet energy, demand, and other grid attribute needs. For resource planning we have traditionally focused on Capacity Expansion (CE) modeling, which inherently includes some system dispatch analysis. We are now also conducting more robust, hourly chronological dispatch analysis via the EnCompass Production Cost Model (PCM) functionality. We note that these and the more detailed models used for network reliability and transmission planning, are intended to address system needs at different levels of granularity; thus, they are able to assess different resource attributes. Further, since we have just acquired the new EnCompass model, it is important to note that we are continuing to explore and test the best approaches and methodologies we can leverage to model our future system in the most realistic way possible. Our approaches may evolve in the future as we better understand the capabilities of the tool and/or learn of new novel approaches to power systems modeling as part of long-term resource planning. That said, we discuss these models' general capabilities – and limitations – with respect to incorporating resource attribute considerations into resource planning modeling further below.

Figure VI-2: Planning Model Capabilities

	Capacity Expansion	Production Cost	Network Reliability
Objective	▪ Solve for a least cost-expansion plan for medium-long term generation portfolio	▪ Simulates hourly chronological dispatch and system operations for a CE-defined portfolio	▪ Test essential reliability service conditions of a defined portfolio
Functionality	▪ High-level system simulation to determine capacity adequacy needs and least-cost portfolios, given assumptions about future demand, fuel and technology costs, and policy parameters ▪ Provides annual generation portfolios and associated costs, carbon emissions estimates	▪ Uses outputs of capacity expansion to conduct hourly chronological system dispatch simulations ▪ Evaluates unserved energy/loss of load; zonal or nodal marginal pricing; some ancillary services	▪ Analyzes transmission network to simulate essential reliability service conditions under contingencies, uncover potential failures ▪ Includes power flow, system dynamics modeling; typically run by ISOs/RTOs
Time granularity	▪ Annual, based on representative days or weeks	▪ Generally hourly, some capable of sub-hourly assessment	▪ Minute-by-minute, or shorter durations
Attributes assessed	▪ Capacity adequacy, some flexibility	▪ Capacity adequacy, energy adequacy, flexibility (e.g. ramp rates)	▪ Essential reliability services, such as frequency response and transient stability
Examples	▪ **Strategist, EnCompass,** RESOLVE, Aurora	▪ **EnCompass**, PLEXOS, RECAP, PROMOD	▪ Positive Sequence Load Flow, Power System Simulator for Engineering

1. *Capacity Expansion Modeling*

Historically, we have used CE models, such as Strategist, to evaluate least-cost resource portfolios to meet a forecast of long-range customer needs. It does this by evaluating energy and capacity needs in each year and selecting least-cost generic resource options that fill those deficiencies. In the course of CE modeling, Strategist performs simplified dispatch analyses using load duration curves that examine a subset of representative hours across the year. In our analysis specifically, Strategist takes 2,014 hours of load for each year – one week from each month– and arranges the load from highest to lowest, creating a load duration curve. It then simulates a resource portfolio dispatch that ensures that energy is procured to serve the annual load, which is later adjusted to account for market purchase and sales opportunities.

Capacity expansion models like Strategist are valuable tools for resource planning, but they are inherently limited in the breadth of resource attributes they can assess. Strategist makes resource decisions based on load duration curves, which do not fully capture the challenges of balancing large quantities of renewable energy that produce hour by hour fluctuation in system energy needs, and its dispatch modeling functionality is simplified to representative weeks. Therefore, it does not provide complete information about a given portfolio's ability to meet flexibility or other essential reliability service attributes. In the past, when significant portions of customer needs were supplied by baseload resources or intermediate and peaking resources that could be more easily controlled to follow load, these aspects of a resource portfolio were less prominent considerations; traditional resources inherently provided all of those things.

However, as variable renewable resources have become a larger proportion of our total resource portfolio – both because of increased renewable adoption and retirement of legacy thermal resources – some CE models' annual capacity adequacy assessments and simplified load duration curve dispatch approaches are no longer necessarily good tools to fully assess and ensure energy availability in every hour across the year. We note that these are limitations associated both with modeling capabilities and resource adequacy (RA) constructs, the latter of which we discuss further below.

2. *Production Cost Modeling*

Production cost modeling represents the next step in understanding intraday availability and flexibility need on the systems. Production cost models use the outputs of capacity expansion modeling (i.e. the preferred generation portfolio expansion plans) to perform hourly chronological dispatch simulations that provide better insight into a system's intraday reliability, availability and flexibility needs. For example, assessing hourly profiles for resources and load helps planners identify whether a proposed portfolio could result in hours with unserved energy or a high reliance on market energy. It can also show the extent to which a system's net load changes across hours, indicating whether the proposed system can accommodate ramping needs.

As described in Section II of this Supplement, we used EnCompass modeling both to conduct capacity expansion modeling and the more detailed hourly production cost modeling, to better assess our scenarios' cost impacts, energy adequacy and flexibility. First, we use the EnCompass capacity expansion functionality to define capacity expansion plans for each baseload scenario. For capacity expansion, we used EnCompass capabilities to simplify hourly system inputs to a sampling of representative days and on- or off-peak time periods, in order to improve model performance and runtime efficiency. However, after the expansion plans were defined, we used the model's full 8,760-hour chronological modeling capabilities to run analyses testing cost for each year from 2020 to 2045. We have also tested individual portfolio results for reliability aspects in 2034, which is the last year of our planning period.

In order to move from a more simplified load duration curve analysis into EnCompass hourly dispatch modeling, we used hourly load and generation profiles for each year of the forecast and incorporated Typical Meteorological Year (TMY) shapes for renewable generation profiles. The TMY shapes provide indications of hourly renewable generation levels we may expect to see over the course of a year with average weather conditions. While using historical weather proxies to estimate future load and renewable availability is a fairly common modeling practice, it is limited in that it does not effectively capture extreme weather events that our system may encounter in a given year – such as an extreme heat wave in the summer, or a polar vortex condition in the winter. That said, historical proxies provide helpful information for examining the present value cost, emissions profiles, and reliability of our capacity expansion portfolios under "average" conditions. This analysis also allows us to examine whether the portfolio defined by capacity expansion modeling would result in any periods of unserved energy, or tight reserve margins, or increasing ramping needs in given times during an average year. If CE modeling is sufficiently covering energy and capacity needs across an average year, however, we would not expect this phase of analysis to uncover any reliability challenges.

After examining portfolio performance based on a typical year, however, we also want to ensure that our system remains reliable under more extreme conditions. The reliability analyses we conducted on our Supplement Preferred Plan (Scenario 9) and selected Scenario 9 sensitivities examine their performance under historical meteorological conditions from a previous year, in this case 2019. To assess reliability risks, we examined how these sensitivities perform on metrics such as duration and quantity of net internal capacity shortfalls, maximum import needs, maximum ramping needs, and standard industry metrics. Our preliminary analyses show that there is reliability risk associated with some sensitivity portfolios under stress conditions, and this risk increases in sensitivity portfolios that include higher ratios of variable generation to peak load. These findings are detailed further in Section II of this filing and Attachment A Section XII. That said, we continue to examine EnCompass capabilities related to reliability analysis and will continue to develop new insights as we work more with the tool.

3. Intersection of Resource Planning and Transmission Planning

This hourly chronological modeling process represents a necessary incremental step forward in understanding how our system will operate in future with more variable renewables. In particular, we note that, when modeling our Resource Plan with EnCompass and adjusting capacity accreditation for updated MISO assumptions, we no longer directly imposed any *ex ante* Reliability Requirement, like we did in our initial July 2019 Resource Plan. EnCompass better reflects actual market conditions, and therefore selected resources that provide sufficient energy availability and flexibility attributes given load and renewable shape assumptions, as compared to the results from Strategist modeling.

That said, hourly production cost models like EnCompass also have limitations. While its hourly granularity is an improvement over Strategist's capabilities, there are aspects of system flexibility – alongside most essential reliability services – that occur on a sub-hourly basis. An hourly model may not capture all the value a fast-burst resource like battery energy storage can provide, such as very fast response to frequency drops or ramping needs, for example. Further, hourly resource planning modeling cannot replace the more detailed power flow modeling and dynamic system modeling that occurs in transmission system planning processes. These models consider an additional component – a generator's location – that is not studied in the course of typical resource planning. Transmission planning models also examine grid reliability and stability impacts of specific resource additions or subtractions at very granular timescales. Ultimately, capacity expansion, production cost, and transmission planning modeling are related but separate practices with distinct objectives

Additionally, most models, including EnCompass, have a "perfect foresight bias," wherein the model perfectly solves for factors that are, in reality, subject to a degree of randomness and variability. These include future load and load profiles, renewable generation, and unit forced outages. The system dispatcher does not have this perfect foresight, and prudently incorporates a level of risk aversion into actual operations (i.e. having extra resources committed and online) that the models do not capture.

4. Resource Adequacy Constructs and Effects on Resource Planning

As noted above, increasing levels of renewable adoption and baseload retirements mean that modeling and evaluating future resource plans using only CE modeling only is no longer sufficient to ensure energy adequacy in every hour of every day. This challenge is attributable in part to modeling capabilities, as discussed above, but also outmoded RA constructs that do not effectively capture variability. Our existing

RA requirements only provide values for the year ahead, based on a year's peak demand hour, rather than providing forward looking or seasonally adjusted values. When renewable resources' share of the total system is relatively low, it is reasonable to assume the other resources – which often have been firm traditional resources or the market – will be able to meet customers' needs. In other words, when most generation is dispatchable, these limitations represent a low risk that a portfolio could be capacity sufficient but result in unmet energy or flexibility needs.

As we add more variable renewables to our system going forward, capacity adequacy and energy adequacy begin to decouple, increasing the risk that a portfolio could appear capacity sufficient – given existing RA constructs – but result in flexibility or energy availability shortfalls. We have partially mitigated this effect in our Supplement by using MISO MTEP forward-looking RA values for solar capacity, rather than using the most recent year-ahead RA values, which helps account for solar's natural marginal declining ELCC as adoption increases.[55] However, variable renewables are also weather dependent, and an annual peak measure still does not indicate these resources' contributions to ensuring our system has sufficient energy to serve customers in all hours of the year. As a result, normal monthly or seasonal variation in renewable availability is not perfectly reflected in CE modeling alone; it is apparent that variable renewables often do not produce at these levels throughout the year and are sometimes unavailable for multiple days at a time. Recent examples of multi-day unavailability in the MISO area and our system, respectively, are depicted in the Figures below.

[55] We note that MISO is further examining declining ELCC for variable resources as adoption increases, in its *Renewable Integration Impact Assessment* work as well. As renewable penetration on the system increases, risk of load loss shifts and each incremental renewable resource is less able to mitigate that risk. *See* https://cdn.misoenergy.org/20191114%20RIIA%20Workshop%20Item%203%20Resource%20Adequacy400382.pdf. The California ISO already requires load serving entities to assess monthly ELCC variations in their RA procurement practices and assumes declining marginal ELCC for solar in their Integrated Resource Planning processes. California's approach to variable renewable resource capacity accreditation is discussed further below, in Section 3.

Figure VI-3: MISO Observed Wind Output Relative to Average Available Capacity[56] – December 2, 2019 to February 23, 2020

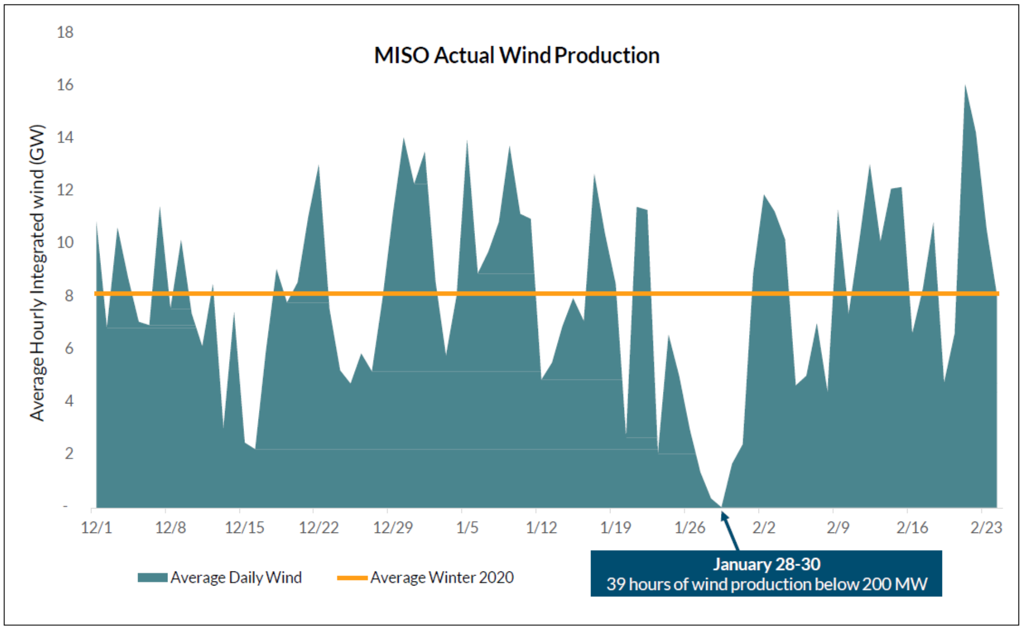
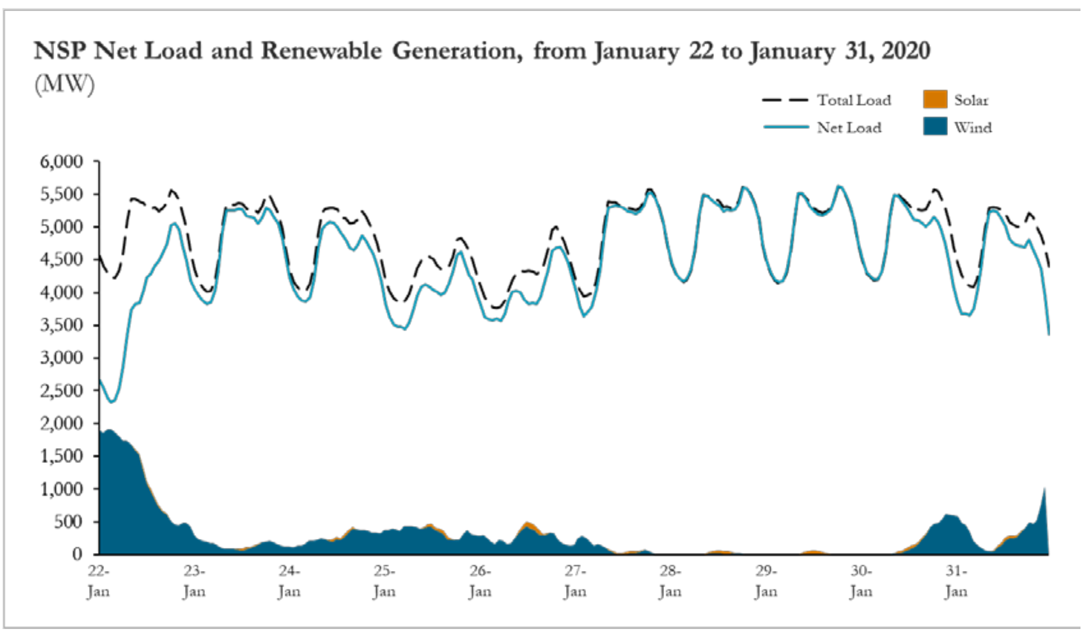


Figure VI-4: Xcel Energy Upper Midwest Net Load During a Multi-Day Renewable Drought – January 22-31, 2020



[56] *See* "MISO Operations Report," (March 24, 2020) at 7. Available at: https://cdn.misoenergy.org/20200324%20Markets%20Committee%20of%20the%20BOD%20Item%2005%20MISO%20Operations%20Report437854.pdf

Renewable drought conditions such as those illustrated above leave a large gap between customer demand and variable renewable resources' availability to serve it in a given hour. We note that, in the NSP system example, customers did not experience system-wide disruption to their service during this time, in part because we have sufficient responsive capacity on the system to accommodate these levels of net demand over sustained periods. We can also rely on the MISO market to fill some of these needs; however, the extent to which we rely on the market to provide energy at the time we need it introduces a risk tradeoff that must be considered.

For example, there is a technical import limit of approximately 2,300 MW into our system from the broader MISO area, although the available import/export capacity varies – sometimes significantly – by hour.[57] To the extent we rely on market purchases and import capabilities, they are considered non-firm and as such, are not dedicated and guaranteed to serve our system at any time needed. And our ability to purchase up to the current 2,300 MW import limit depends on timely available excess to generation from neighboring utilities or merchant generators in MISO. While a market that spans a broader geographic area can improve variable renewables' overall contribution to load, there may also be weather correlation and associated price risks to manage within or between adjacent market zones. In other words, our neighboring utilities and merchant generators may not always have sufficient excess energy or capacity to sell to meet an internal shortfall on our system, especially if that shortfall results from broader regional weather events.[58]

Currently, some of this risk can be mitigated by improved forecasting capabilities and planning for other generators to ramp up in response. However, were our shortfall to exceed the available import capability at a given time, and we did not have sufficient firm capacity available for us to deploy to make-up for that shortfall, customers would experience a load shedding event regardless of whether the shortfall were forecasted in advance. Thus, potential renewable drought conditions will introduce increasing risks in maintaining reliability on the grid, as variable resources become a higher and higher share of our energy mix and legacy thermal generation retires. Our planning approaches and constructs also will need to adapt in order to better capture these conditions and the resulting hourly variation in net demand and energy availability.

[57] We note that our current production cost modeling process assumes the NSP system's full import capability is always available and cannot dynamically adjust to modeled market conditions in the remainder of MISO. We model market interactions with the remainder of MISO using forward curve market price assumptions at import nodes, rather than modeling dynamic market interactions. As a result, our modeling does not capture potential constraints on our import capability that may arise from correlations in increased market reliance amongst other market participants.

[58] If reduced renewable availability, for example, were widespread throughout upper MISO and adjoining Southwest Power Pool regions – which past operational data has indicated at times – the price of procuring from the market could increase substantially for several hours at a time.

Hourly chronological dispatch modeling, such as the PCM functionality in EnCompass, gives us additional insight into these intra-day and inter-day hourly conditions. For example, examining our system's energy and capacity availability over 8,760 hours allows us to evaluate whether there are time periods in which our system risks capacity shortfalls, periods of unserved energy, or significant ramping events. Increasing prevalence, or long duration periods, of market reliance is a financial and reliability risk to customers and may also indicate that the resources on our system in that analysis year would be insufficient to meet customer needs, if our import capability were constrained. In particular, as the largest member of MISO Zone 1, our import needs may correlate with other Zone 1 members' needs and therefore, the full import capabilities for the Zone may not be available to only our system – creating a shortfall for our customers.

All said, the challenges associated with a system transitioning to higher levels of variable renewable dependence make it increasingly important that MISO RA constructs appropriately reflect variable renewables' potential impacts to a grid. Thus, one goal inherent in our resource plan modeling is to maintain enough responsive capacity to hedge customers' risk of being exposed to drastic price spikes or load shedding events, when ramping events or long duration renewable droughts occur.

C. Emerging Methods of Evaluating Resource Attributes

As we continue to develop our modeling processes to more adequately reflect system needs through our transition to a cleaner grid, new resource assessment methods in both planning and procurement processes are emerging.[59] These include flexibility-specific RA, more granular or forward-looking ELCC evaluations, using risk metrics – such as Loss of Load Probability (LOLP) in determining reliability surety instead of a static reserve margin or ELCC – and even factoring resource attribute considerations into the modeled costs of different energy technologies. The Company's modeling will continue to evolve to best reflect system conditions and MISO guidelines, and we may also examine using additional approaches to examine the adequacy of our portfolio's resource attributes in the future.

[59] As discussed in our initial filing and noted herein, MISO's *Resource Availability and Need* and *Renewable Integration Impact Assessment* efforts are a step toward examining the potential for new RA constructs and resource attribute analyses in our region. In our initial filing we discuss these initiatives in Chapter II. Planning Landscape and Appendix J2 – Reliability Requirement.

1. *Flexibility-Specific Resource Adequacy Constructs*

Some utilities and markets across the country explicitly value flexibility in their resource planning or RA processes. For example, Public Service Company of New Mexico (PNM) has implemented a method of examining potential shortfalls in flexibility in its production cost modeling. The traditional method of examining LOLE measures capacity adequacy at peak conditions, meaning that it evaluates the probability that capacity available on the system would be insufficient to meet the day's peak needs. PNM worked with Astrape Consulting to develop and evaluate a modified measure called $\text{LOLE}_{\text{Flex}}$, which examines potential load shedding events resulting from insufficient system ramping capability. It evaluates these events in a PCM software called SERVM, both on an inter- and intra-hour basis.

The system ramping metric is instructive as variable renewables increase on the system, because even predictable ramping events can result in load shedding if there are not enough flexible resources on the system to respond. This is especially the case in areas where substantial solar development exacerbates the trajectory of evening ramping needs, as net demand can increase rapidly over a short period of time when solar output declines and customer demand increases simultaneously. Where the model finds potential $\text{LOLE}_{\text{Flex}}$ events, it includes the cost of unserved energy in its production cost totals; planners can use this information to evaluate the opportunity cost of mitigation, such as changing operational procedures like increasing market operating reserves or adding flexible resources to mitigate loss of load risk during extreme ramping events.[60]

The California Public Utility Commission (CPUC) instituted a flexibility-specific RA metric in load serving entities' annual RA procurement processes in 2013.[61] Under this construct, the California Independent System Operator (CAISO) evaluates expected flexibility needs for the year ahead based on forecasted net load ramping need analyses, and the CPUC subsequently sets load serving entities' flexible RA procurement requirements.[62] Flex RA requirements are especially essential to the

[60] *See* Astrape Consulting. "PNM Preliminary Reliability Analysis." April 18, 2017 at 26. Available at: https://www.pnm.com/documents/396023/3306887/04182017-irp-mtg-reliability/66b6bdc0-d9d4-4f72-b1dc-076d8c5c74c2
[61] *See* D.13-06-024 *Decision Adopting Local Procurement Obligations for 2014, A Flexible Capacity Framework, and Further Refining the Resource Adequacy Program* (June 27, 2013).
[62] Note that CPUC-jurisdictional load serving entities generally do not own generation assets (with some exceptions) and the CPUC oversees reliability procurement. We note that the CPUC recently instituted a central procurement construct, assigning two large utilities to conduct local reliability procurement on behalf of all jurisdictional load-serving entities, in order to ensure multi-year local RA requirements are cost-effectively achieved. *See* Docket No. R.17-09-020. "CPUC Adopts Central Procurement Framework for Local Resource Adequacy." Available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M340/K048/340048112.PDF

California system because of the "duck-curve" phenomenon, where high mid-day solar generation can cause steep three-hour ramping needs, sometimes exceeding 10,000 MW in the spring when daytime load is relatively low.

2. ELCC Values in Procurement and Planning

Several utilities in the United States now utilize ELCC values that change over time to better reflect how increased adoption will affect variable or use-limited resources' capacity value.[63] For planning, utilities may move from using current ELCC values across the planning period to instead, estimating forward-looking measures, in order to better reflect how additional build-out will affect the overall capacity value of their portfolios. For near-term procurement constructs, some jurisdictions use ELCC values that reflect monthly or seasonal differences in expected resource availability and production capabilities. The CPUC provides examples of both of these developments, but other utilities are also exploring opportunities to improve reliability planning as their clean energy transitions progress.

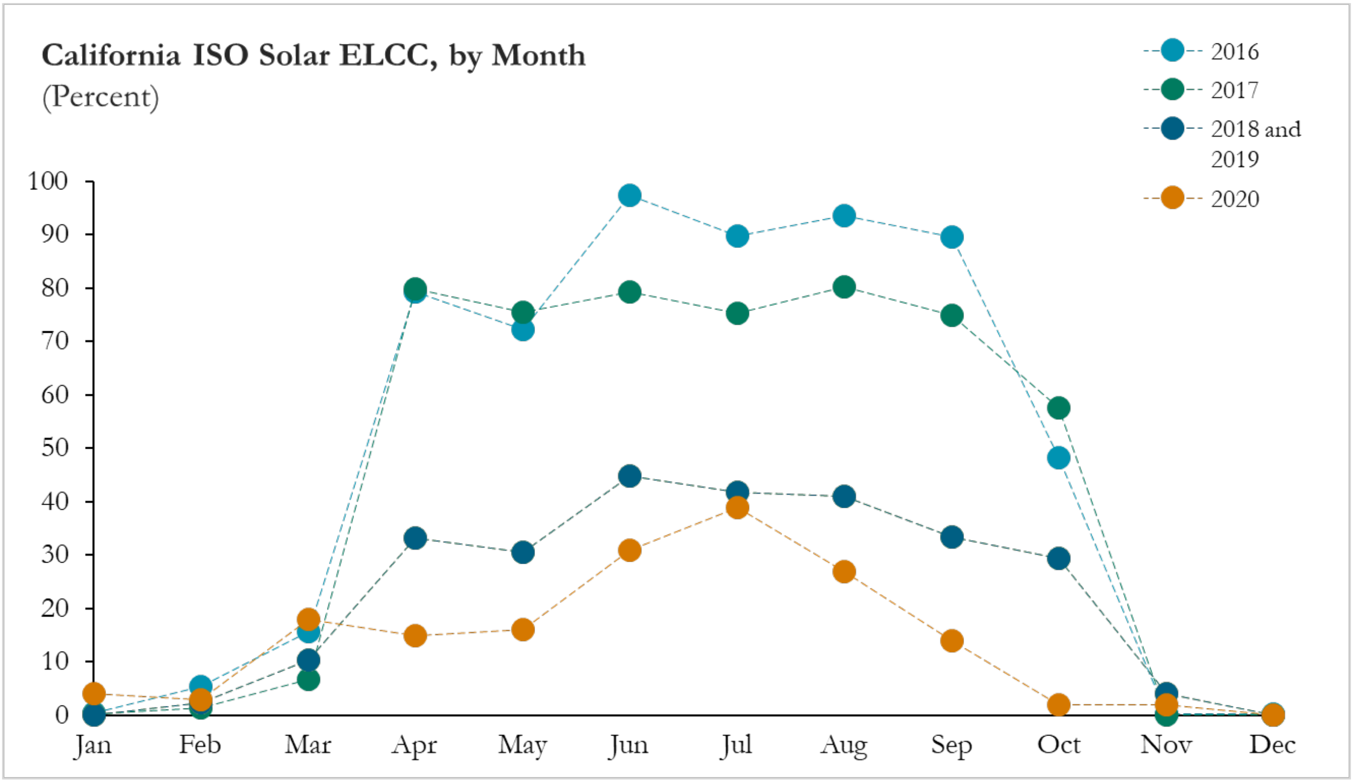
In its RA procurement requirements, the CPUC has begun to use monthly average ELCC values to determine variable renewable resources' qualifying capacity. The CPUC asserts that using a single annual peak value for this purpose would be inappropriate, stating:

> ELCC values based on a study of just the peak months are not sufficient for this purpose, due to the highly variable ELCC value of these resources depending particularly in the case of solar and wind, on monthly patterns of electric demand and weather patterns."[64]

We note that the CPUC's assigned monthly solar ELCC values have also declined significantly over time, as solar has increased as a share of total capacity in the broader system. We portray the change in monthly ELCC values since 2016 in the below Figure.

[63] As indicated in Section II, these include DTE Energy, Indianapolis Power & Light, Dominion Virginia, Vectren and others.
[64] *See* D.19-06-026 *Decision Adopting Local Capacity Obligations for 2020-2022, Adopting Flexible Capacity Obligations for 2020, and Refining the Resource Adequacy Program.* (June 27,2019) at Appendix A1.

Figure VI-5: California ISO Solar ELCC, by Month[65]



The CPUC has further implemented an expectation of forward-looking ELCC into its resource planning process. In guidance for the current resource planning cycle for CPUC-jurisdictional load serving entities conducting their own production cost modeling, CPUC staff provided guidance that includes forward-looking average annual ELCC assumptions. These values are based on state-level reference plans that achieve specific greenhouse gas emissions thresholds.[66]

3. *Value Adjusted Levelized Cost of Energy*

Another approach to incorporating resource attributes into planning involves valuing capacity, energy, and flexibility directly, in a modified levelized cost of energy (LCOE) metric. This approach recognizes that pure levelized cost calculations do not fully capture all the grid attributes various resource types can provide, but rather than

[65] Note: Assigned ELCC values for 2019 were the same as 2018. Data available at: http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx
[66] *See* Docket No. R.16-02-007. "ELCC assumptions used within the Resource Data Template," (May 12, 2020). Available at: ftp://ftp.cpuc.ca.gov/energy/modeling/ELCC_assumptions_used_within_the_Resource_Data_Template.xlsx

modeling attribute values through separate processes, they could be captured in a common valuation metric that would allow better comparison across resource types.

The International Energy Agency (IEA) has adopted this approach in their latest World Energy Outlook (WEO). The WEO is an annual report that attempts to project global energy demand and the capacity expansion expected to meet these needs under a given set of market and policy assumptions. IEA developed a metric called the Value Adjusted Levelized Cost of Energy (VALCOE) that combines each resource type's pure levelized cost with estimated value attributes for capacity, energy, and flexibility. The IEA describes the need for a value-adjusted cost comparison approach in the following way:

> While LCOE has the advantage of compressing all the direct technology costs into a single metric which is easy to understand, it nevertheless has significant shortcomings: it lacks representation of value or indirect costs to the system and it is particularly poor for comparing technologies that operate differently (e.g. variable renewables and dispatchable technologies). VALCOE enables comparisons that take account of both cost and value to be made between variable renewables and dispatchable thermal technologies.[67]

We are not aware of any utilities or regulatory agencies in the United States that use this approach currently. However, we expect value-adjusted methods will be considered as the industry continues to transition away from traditional thermal sources and incorporates increasing levels of variable renewables and fast-burst resources.

[67] *See* IEA. "World Energy Model Documentation," 2019 Version, at 44.

VII. BLACK START

Black start resources are a critical component of system resilience and long-term reliability. In our initial filing, we noted that planned system retirements over the next several years will affect our current black start plans, and that we were analyzing options for the best path forward. While we continue that work, we believed it was important to include placeholder capacity and costs for a potential future black start solution in our supplemental modeling. To be clear, this modeling proxy does not represent our proposal; rather including placeholder capacity allows us to show how our eventual proposed black start resources may fit into and impact our overall Preferred Plan. Below we briefly discuss what black start is, why it essential to maintain black start resources on our system and provide further discussion regarding how we have represented black start resources in our modeling.

A. Black Start Fundamentals

Black start resources and standards surrounding restoration plans have been an essential part of utility reliability planning for several decades.[68] These resources are comprised of the generating units and transmission infrastructure the Company must maintain in order to restart the system in the event of a widespread or catastrophic grid outage. While rare, bulk electric system blackouts require transmission and generation operators across an affected area to work together, in order to carefully and incrementally balance electricity generation as it is restored alongside customer load. This helps to ensure the broader system regains and maintains stability as operators restore individual grid "islands" and reconnect these islands until the full grid is operational again.

More specifically, the North American Energy Reliability Corporation (NERC) defines sets of standards for both Transmission and Generation Operators regarding the characteristics of viable restoration plans and black start generation resources – and rules governing these entities' interaction with the Reliability Coordinator in a given region – which they outline in Emergency Operating Procedure (EOP) 005-3. For the NSP system, we are both the Generation and Transmission Operator, and MISO is the Reliability Coordinator. Under this procedure, each Transmission Operator must maintain a restoration plan, in cooperation with the regional Reliability Coordinator, that meets several specific requirements. Required components include:

[68] NERC, for example, has had black start restoration plan guidelines since at least 1993.

- identifying black start resources and their characteristics to be used to restart the system in the event of a widespread outage;
- the process of restoring loads required to balance and stabilize generation resources;
- identifying a cranking path between the black start resources and subsequent units incrementally, to restore other generation units on the system;[69]
- and procedures to reconnect neighboring grid areas when they are stable, in order to restore the broader interconnected grid.[70]

Each Generation Operator providing black start service must ensure its black start-designated units can start and run unloaded – without external support from the system – and meet the Transmission Operator's restoration plan requirements for real and reactive power. MISO further provides a list of requirements pertaining to black start generating units in their Business Practice Manual 022. According to MISO, black start-capable generation resources in its area must have the following characteristics:

- capability of operating at zero load for a time period as required to accomplish the Transmission Operator's Restoration Plan, and to close on a dead bus;
- sufficient reactive reserve capability to energize the transmission system to supply the facility with restoration power;
- adequate inventory of fuel supply to accomplish the Restoration Plan;
- be periodically tested to ensure availability and capability to supply useful energy (e.g. meeting sufficient quantity of energy, and frequency and voltage requirements) to the station bus in an acceptable time period, as defined by the Transmission Operator and regional reliability entity.[71]

Given these special requirements, not every generation unit on the grid is configured to provide black start services; units require special controls to be able to run unloaded and support transmission frequency control, so the plants are often

[69] We note that nuclear units have specific station power restoration requirements to maintain critical controls, even though nuclear units are some of the last to be brought back fully online to serve customer load. Our NERC operating agreements for Monticello and Prairie Island require station power restoration within four hours of a grid outage.
[70] *See* NERC "Reliability Standards for the Bulk Electric Systems of North America," EOP 005-3. Updated January 2020. Available at: https://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States
[71] *See* MISO "Blackstart Service Business Practice Manual," BPM-022-r10. Effective September 2018. Available at: https://www.misoenergy.org/legal/business-practice-manuals/

specifically designed to be black-start-capable when first constructed. However, black-start-capable units can and do run during normal operations, often providing firm and dispatchable peaking capacity to the grid.

In NSP's restoration plans, the description of black start resources above refers to what we have termed "Initial Units." Our Initial Units have a secure fuel supply, can help jumpstart our system with no outside grid support and can reenergize part of the transmission system, and run for up to a full day on little to no load. There are also second-step "Target Units" that receive station power from the Initial Units in order to start, and that subsequently provide additional energy and grid stability necessary to restart and stabilize the remainder of the system. We have both Target and Initial Units in each the NSP-Minnesota and NSP-Wisconsin systems, as maintaining distinct black start plans for both operating companies facilitates faster restoration for our broader Upper Midwest system. Both types of units can provide valuable energy and capacity during normal operations as well.

Restoration in a careful, but timely, manner after a catastrophic event is essential to the health and wellbeing of our customers and the broader economy. Long duration outages spread over a broad area can mean millions of dollars of lost economic activity[72] and can be associated with serious negative health effects for certain customers as well. Timely and robust restoration on our system is also essential to our neighboring utility service areas, as interconnected systems often depend on each other to complete their own restoration processes.

B. Resource Modeling and Black Start Units

As noted above, black start events are high impact but rare. As such, our resource plan modeling does not capture the full value these units provide our system. However, because both Initial and Target Units can also provide the grid with energy and capacity during normal operations, they are included in our capacity expansion and production cost modeling processes. Today, our existing Initial Units and Target Units in both Minnesota and Wisconsin are part of the over 3,000 MW of firm coal and gas capacity slated for retirement or contract expiration within the planning period; this is even before including our proposed Preferred Plan retirements for King

[72] For example, studies suggest that the last widespread regional grid outage in the Eastern Interconnection – in August 2003 – affected 50 million people in the US and Canada and had negative economic impacts in the range of $4.5-8.2 billion dollars. *See* Electricity Consumers Resource Council, "Economic Impacts of the August 2003 Blackout," (February 2004) at 1. Available at: https://elcon.org/wp-content/uploads/Economic20Impacts20of20August20200320Blackout1.pdf

and Sherco 3, which would add another 1,000 MW to that total. Many of these retiring units will be over 40 years old at their expected retirement dates.

As noted in our previous Resource Plan filings[73] the Sherco site is currently a critical piece of our Minnesota black start plans. Sherco Units 1 and 2 currently serve as our Target Units and as they retire in 2026 and 2023 respectively, we will need to develop alternative restoration path and Target Unit options. One key benefit of the new Sherco CC is that it replaces many of the grid attributes our coal units currently provide, but with more flexible capabilities and substantially less carbon emitted. We expect that the plant would play an important role in the event of a widespread grid outage, providing a large, stable generating source that we build upon to restore larger and larger portions of the grid. Further, it can enable the site to continue supporting restoration and maintenance of auxiliary power at our nuclear units, until they can be brought fully online later in the restoration process. That said, we continue to evaluate Target Unit options as part of our black start planning processes.

As discussed previously, Target Units cannot start from a fully de-energized grid on their own. We need specially-sized and equipped Initial Units to jumpstart the restoration process, after which the larger firm dispatchable Target Units can be started and balanced with increments of customer load. After the system achieves stability with those resources, variable renewable resources and finally the nuclear units can be added, completing the restoration process; a process which, in total, spans several days. In addition to the ability to start without outside support, the unique attributes of our Initial Units align with NERC requirements, as they have a secure fuel supply and the capability to run as an island with no balancing load. Proximity to load centers is also a benefit, given small increments of customer load are important building blocks to restoring the full system.

Our full black start alternatives analysis is still underway, and we are working to identify various potential options for black start-critical resources – in both our Minnesota and Wisconsin systems – going forward. However, we do know that that if all planned resource retirements are pursued, and none of the capacity is replaced with units that can provide similar grid attributes, we would not have sufficient black-start-capable resources available internal to our integrated Upper Midwest system to fulfill our complete restoration plans. We would then be forced to rely on neighboring utilities to support our restoration, which could not only result in extended outages for our customers, but also – as a result of interdependencies between systems – make restoration of the broader regional grid a longer and more challenging process. Thus,

[73] Both the 2016-2030 Resource Plan (Docket No. E002/RP-15-21) and our Initial filing in the instant docket.

we have represented this essential resource capability in our Supplement Preferred Plan via a modeling proxy that **[PROTECTED DATA BEGINS…**

…PROTECTED DATA ENDS]. In total, these resources provide approximately 430 MW of accredited[74] black-start capable peaking capacity to the NSP System. Our modeling also includes cost assumptions that **[PROTECTED DATA BEGINS…**

…PROTECTED DATA ENDS]. In total, this placeholder results in approximately **[PROTECTED DATA BEGINS…** **…PROTECTED DATA ENDS]** added to all scenarios in order appropriately model necessary black start resources.

We emphasize, however, that that this proxy approach is only an interim placeholder and does not constitute a proposal for resources required for our long-term black start plan. We continue to examine a broad range of alternatives that will provide the needed system resilience and reliability benefits, long-term cost-effectiveness, and consider and balance environmental impacts; these alternatives include building new units, retrofitting existing units, and energy storage technology options.

[74] Note that this corresponds to approximately 620 MW of max capacity.

VIII. NUCLEAR UPDATE

As discussed in the Supplement Preferred Plan, carbon-free nuclear generation continues to be a cornerstone of our plan to serve customers with increasingly clean energy. In Appendix K of our initial filing we discussed how our nuclear fleet performance has become even more cost effective, while achieving stringent safety performance targets in recent years. We also discussed in more detail the role we envision nuclear power playing in our Supplement Preferred Plan going forward, including the proposed Monticello life extension and continued operation of Prairie Island 1 and 2 at least through their existing license lives.

Since last July, we have completed another year of strong performance at our units, achieving high capacity factors at low operational costs while maintaining high standards of safety. We safely completed two re-fueling outages while ensuring that the units could rapidly and safely return to operations and continue serving our customers with reliable carbon-free generation. We also continue to innovate, pressing ahead with plans to operate our units flexibly, to be more responsive to the availability of variable generation. Further positioning our nuclear fleet to be an essential piece of the carbon reduction story going forward, we will soon kick off a new demonstration project in partnership with Idaho National Laboratory (INL) and the U.S. Department of Energy (DOE) to examine the economic feasibility of using low-cost nuclear energy to produce clean hydrogen that can be burned for energy later, as a manner of time-shifting carbon-free generation. Our continued focus on operational excellence, alongside innovative new applications, demonstrates the value of our nuclear fleet beyond the standard baseload clean generation that have made these plants a key part of our energy mix for decades.

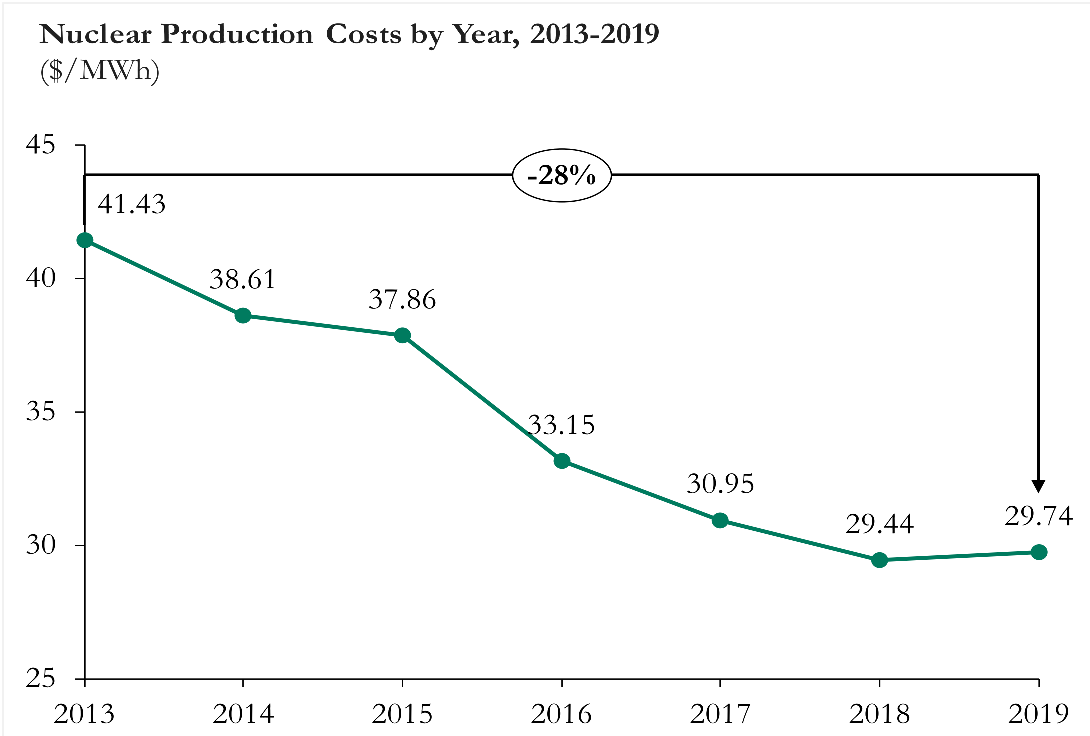
Our updated capacity expansion modeling continues to validate that view, as it shows that extending nuclear units results in a lower cost future generation portfolio than our Reference Case, in which they are taken offline when their current licenses expire in the early 2030's. The continued operation of our nuclear fleet is critical to the Company's achievement of our carbon reduction goals, including reducing carbon emissions by 80 percent from 2005 levels by 2030. Therefore, as part of our Supplement Preferred Plan, we continue to ask the Commission to approve a five-year action plan that includes starting to work on a Supplemental License Renewal (SLR) application for Monticello with the Nuclear Regulatory Commission (NRC). We also continue to acknowledge that, although several less expensive scenarios include a Prairie Island extension as well, the Company is still working with the surrounding community and proposes to revisit the potential for a Prairie Island license extension in the future.

A. Nuclear Fleet Performance

Our nuclear fleet continues to perform exceptionally well, in keeping with our efforts to reduce costs while enhancing operations and safety in recent years. It produced over 14.3 million megawatt hours (MWh) of electricity in 2019 – approximately 30 percent of energy generated by our entire generation fleet in 2019 – which is the second highest generation record since the nuclear fleet began operating. This performance resulted in a nuclear fleet-wide capacity factor of over 92.6 percent. Further, we achieved these above average results while safely completing two planned refueling outages. The refueling outage at Prairie Island Unit 2 was conducted without any reportable events in only 23 days, which is top quartile performance in the industry and the second shortest outage in the history of the unit. We also refueled the Monticello unit in in 30.5 days between April and May 2020.

We achieved these successful operating results while continuing to maintain safety and affordability, through operational excellence. Our fleet achieved its second year in a row of production costs below $30/MWh, which represents a nearly 30 percent decline from 2013 as shown in Figure VIII-1 below. We have reduced our operations and maintenance costs relative to 2018 by nearly $7 million, which represents a more than 2 percent improvement compared to 2018 results and marks the fourth straight year of declining O&M in our nuclear operations. We have achieved these operational savings while continuing to prioritize safety. Both the Monticello and Prairie Island plants have maintained high levels of safety performance, achieving top marks on the industry's rigorous safety evaluations. In fact, our nuclear fleet was recognized as one of the highest performing fleets in the country according to our nuclear industry peer group.

Figure VIII-1: Historical Xcel Energy Nuclear Fleet Production Cost



B. Operational Innovation Updates

The Company's nuclear fleet has been an important source of steady and stable clean baseload generation for several decades. Historically, baseload resources have not been expected to ramp up or down in response to changes in other resources on the system; instead, other intermediate or peaking resources have been adjusted as needed. However, as the fuel mix in our system (and the industry broadly) changes, we are preparing for a future in which our nuclear units may need to achieve more flexible operations and provide for different use cases in order accommodate higher levels of variable renewables on the grid. To this end, we are working on two specific initiatives: first, making our fleet more responsive to expected changes in net load with flexible operations; and second, an innovative pilot project with a federal laboratory to examine nuclear resources' potential role in producing clean hydrogen.

1. *Flexible Operations*

In our initial filing, we discussed a flexible operations strategy that allows our nuclear facilities to reduce power output when wind or solar resources are providing increasingly large amounts of energy relative to customer demand. At these times, the net load our other generating resources need to serve may decline significantly, such that it would even be economically beneficial to run our baseload resources at lower output. In our Upper Midwest system, we already observe some low pricing periods in times of high wind generation, and our Supplement Preferred Plan includes a significant buildout of additional variable renewables. Thus, making our nuclear fleet responsive and able to ramp down during periods of high congestion and low pricing is beneficial to our customers.

Operationally, this means we needed to evaluate our fleet's technical capability to maneuver units from full output to a level of reduced output, and then participate in the MISO market in accordance with this capability. In the past, our nuclear plants were generally offered into the regional power market as "must-run" resources that did not respond to expected inter-day fluctuations in net load. However, in order to accommodate more variable renewables on the grid, we have worked to develop operational strategies that allow us to offer the plants into the MISO Day-Ahead market on an economic basis, allowing for MISO to schedule a portion of the plants to be more responsive to market signals and ramp output accordingly. At the time of our initial filing, we were already bidding Prairie Island Unit 1 into the Day-Ahead Market. Since that time, we have expanded our flexible operations capabilities to all three nuclear units, and at this time we can safely and efficiently ramp up to 280 MW – or over 15 percent – of our nuclear capacity in response to the market. This capability will help us integrate more renewables on our system, while still utilizing our nuclear fleet as a carbon-free, stable and reliable source of energy. In short, our ability to make renewables and nuclear work together helps us increase the amount of clean energy we can provide our customers.

2. Nuclear Hydrogen Pilot

We are also looking for additional opportunities to incorporate our nuclear fleet into our clean energy future. This includes alternate use cases for the low-cost, clean energy produced by our plants, that could allow us to integrate even more variable renewable energy onto the grid.

To this end, we will soon kick off a partnership with INL, the DOE, and two other utilities to examine technical and economic feasibility of using nuclear energy to produce hydrogen through a process called electrolysis. In total, the project will receive approximately $11.5 million in grant funding from the DOE. The Company will receive around $1.3 million of this funding to work with INL to examine the economic feasibility of using our nuclear units' electricity to produce hydrogen fuels. The project will also include deployment of a low-temperature electrolyzer at

FirstEnergy's Davis Besse nuclear plant in Ohio, and another economic feasibility study for the Palo Verde Nuclear Generating Station, owned by Arizona Public Service. The utilities are currently in the final stages of negotiating the project scope with INL and DOE. We expect the pilot to kick off later in 2020 and run through 2022.

The findings from this pilot project have the potential to not only support the Company's goals of achieving 100 percent clean energy by 2050, but also potentially reduce carbon across other sectors. Clean hydrogen produced with energy from our nuclear units could, for example, provide a method of long-duration energy storage and clean firm, dispatchable generation. Instead of ramping down nuclear units during periods of high renewable generation, we could use the excess clean electricity on our system to shift load and produce hydrogen at low cost. That hydrogen could then be used to produce electricity at times when variable renewable generation is not available. Hydrogen is also currently used as key fuel in some industrial processes, such as steel manufacturing, and fleet vehicle operations, but the method currently used to produce it – called steam reformation – uses fossil fuels. Clean electrolysis could support carbon reduction in these heavy manufacturing and industrial processes that are typically challenging to mitigate. Finally, it is possible that clean hydrogen could become an economic fuel source for transportation, supporting carbon reductions in our economy's most carbon-intensive segment.

C. Spent Nuclear Fuel Update

The Company continues to lead discussions of spent nuclear fuel and finding both permanent and interim storage solutions. This is done through a variety of channels including our interactions with Congress and congressional staff, and through industry trade initiatives, such as through the Nuclear Energy Institute (NEI), and the Nuclear Waste Strategy Coalition (NWSC or Coalition).

Xcel Energy was one of the major sponsors and participants in a table top exercise organized by NEI last year at Prairie Island. The exercise was intended to begin the dialogue and foster cooperation among key decisionmakers around the actions needed to transport spent fuel from a reactor site to a consolidated interim storage facility (CISF). The exercise modeled the transportation of spent fuel from a hypothetical nuclear power plant (located between the Prairie Island and Kewaunee sites) to a hypothetical centralized interim storage in the vicinity of the New Mexico/Texas border.

1. *Permanent Repository*

Xcel Energy is working with federal authorities to encourage development of a permanent storage solution. The application to license the Yucca Mountain permanent repository remains pending before the NRC. The NRC Staff's technical and environmental reviews are essentially complete, but the adjudicatory hearings on the application before the NRC Atomic Safety and Licensing Board remain suspended pending Congressional appropriations for both DOE and NRC. Numerous contentions submitted by Nevada and other opponents remain to be litigated and must be resolved before the NRC can license the project.

2. *Consolidated Interim Storage Facility (CISF)*

Two private, interim storage initiatives have submitted licenses for operation to the NRC. If approved, these CISF locations would consolidate and store the spent fuel until the permanent facility is built.

Interim Storage Partners, formed by Orano USA and Waste Control Specialists (WCS), is pursuing a license to construct a consolidated interim storage facility for used nuclear fuel at the existing WCS low-level waste disposal site in Andrews County, Texas. The NRC has issued a draft Environmental Impact Statement that is currently out for public comment and staff's most recent announced date for completing its review of the application and issuing the license is May 2021.

Holtec International has proposed the HI-STORE consolidated interim storage facility for a site in Eddy and Lea Counties in southeastern New Mexico. Holtec filed an application with the NRC for this facility in March 2017. The NRC issued a draft Environmental Impact Statement earlier this year that is currently out for public comment. Public hearings were held on June 24 and another is scheduled for July 9. The NRC Staff's most recently announced date for completing its review of the application and issuing the license is March 2021.

D. The Nuclear Fleet's Role in Our Updated Preferred Plan

Our nuclear units are a cornerstone of our current generation fleet as well as our clean energy future. Since our initial filing, the Company has updated our nuclear budgets in order to ensure our modeling takes into account the most current data, including general operating costs, as well as expected costs to achieve nuclear relicensing, for scenarios that propose extension. Our Supplement modeling continues to show that the lowest cost future generation portfolios include extending our nuclear units beyond their current licenses.

1. Nuclear Budget Updates

We made several updates to our nuclear budgets that feed into our modeling for this Supplement. First, we updated our budgets to reflect 2018 actuals for both capital and O&M. Beyond 2018, we provide an updated capital forecast and an updated O&M forecast from 2019-2022, after which we apply 2 percent annual escalation consistent with our 2019 budget data used for our initial filing. In addition to these changes, we made some modifications to the list of projects to which probabilities are assigned in the long-range plan. However, these changes result in very little overall net change to the estimated capital expenditures for nuclear in our Supplement Preferred Plan. We also updated the expense for the annual decommissioning accrual to align with the Commission's most recent decision in our 2017 Triennial Decommissioning Docket.

Finally, we introduced a refinement to our modeled costs to reflect the fact that we receive annual reimbursements from the DOE for each year's dry fuel storage expenses. Because these DOE reimbursements typically get refunded to customers (or occasionally get applied to customer obligations such as the decommissioning accrual), we concluded that it is reasonable to account for these annual reimbursements in our modeling so as not to overstate the cost of our nuclear operations.

For Monticello, our updated total estimated capital expenditures decreased from our 2019 budget by approximately $0.3 million. Our O&M estimate before loadings increased from our previous budget by approximately $28 million. This increase reflects higher realized 2018 and 2019 O&M results, which are subsequently escalated through 2040. Our budget update also includes a refined outage amortization estimate in the final year of operations.

For Prairie Island, our total capital budget estimate updates, increased relative to our 2019 budget by approximately $20 million for the years 2018 to 2034. Our O&M budget for the years 2020-2034 decreased from the previous budget by approximately $385 million. This adjustment reflects not only reductions in 2018 and 2019 spend compared to prior budgets, but also near-term budgets that are lower than in 2019, due in part to planned continuous improvement efforts. These near-term adjustments are then used to estimate spend out to 2034, which is partially offset by refining outage amortization in the final year of operations.

2. *Nuclear's Role in our Supplement Preferred Plan*

The Company's Supplement Preferred Plan continues to show benefits of a ten-year extension of our Monticello unit, to 2040, and operating Prairie Island units at least through their current license lives. These resources are essential to the achievement of our carbon reduction goals and are part of a cost-effective plan to achieve them. For the purposes of this Supplement, we examined capacity expansion scenarios both in Strategist and EnCompass. While there are some differences in specific portfolio outcomes, results are generally consistent in indicating that extending the lives of our nuclear units supports our system achieving significant carbon reduction in a least-cost manner.

a. Modeled scenarios and results

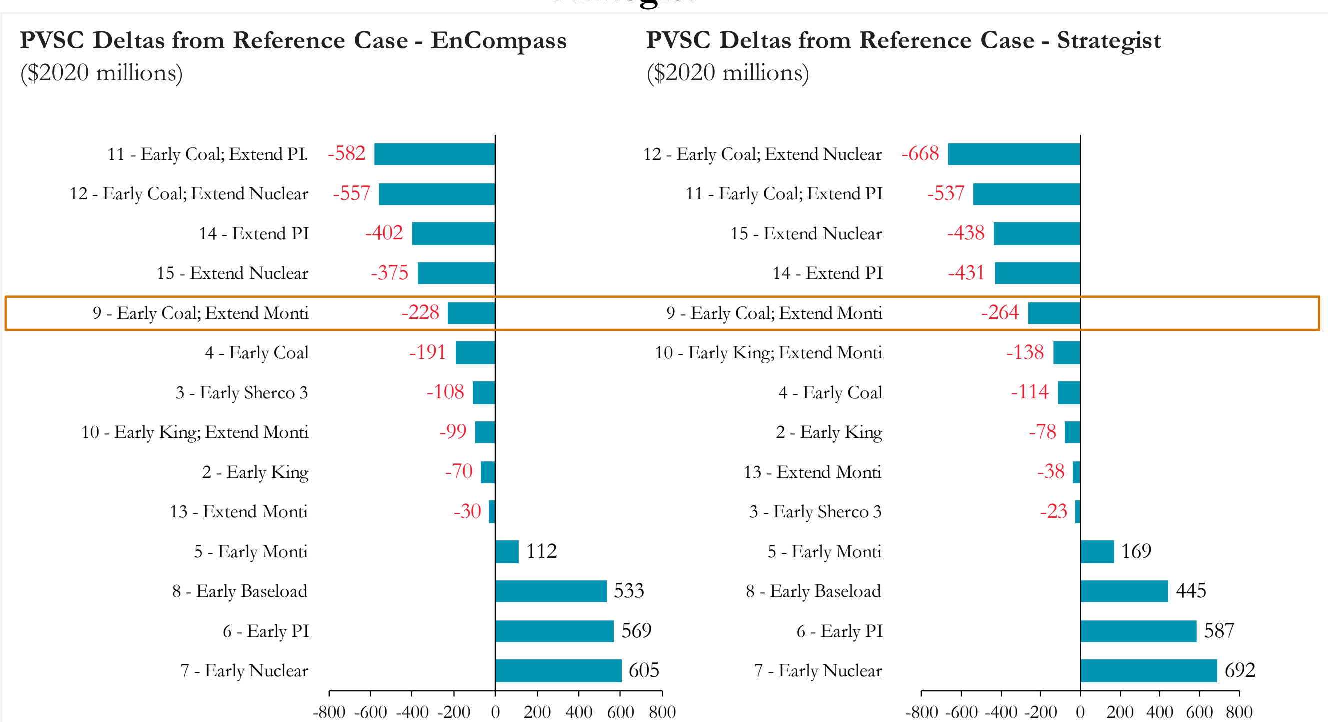
As in our initial filing, we modeled several baseload scenarios in which we tested both the present value of societal cost (PVSC) and present value of revenue requirements (PVRR) outcomes of either retiring early or extending Monticello and Prairie Island (as well as our remaining coal units). Scenarios that include modifications to nuclear retirement dates are:

- 5 – Early Monticello (Monti) Retirement (retires in 2026)
- 6 – Early Prairie Island (PI) Retirement (Units 1 and 2 retire in 2024 and 2025, respectively)
- 7 – Early All Nuclear Retirement (retires Monti and PI early, per dates in Scenarios 5 and 6)
- 8 – Early All Baseload (retires all nuclear early, per dates in Scenarios 5 and 6, and all coal early)
- 9 – Early Coal; Extend Monti (extends Monti operations to 2040 – 10 years beyond its current license life – and retires coal early)
- 10 – Early King; Extend Monti (extends Monti to 2040, while retiring the King coal plant early)
- 11 – Early Coal; Extend PI (PI Units 1 and 2 remain operational until 2043 and 2044 – or 10 years past their current license expirations – and all coal is retired early)

- 12 – Early Coal; Extend All Nuclear (extends all three nuclear units 10 years beyond their current license expiration dates while retiring all coal units early)
- 13 – Extend Monti (Monti remains operational until 2040)
- 14 – Extend PI (Units 1 and 2 remain operational until 2043 and 2044)
- 15 – Extend All Nuclear (extends all three nuclear units 10 years beyond current license expiration dates)

Our updated analysis continues to show that extending the lives of our nuclear units is a beneficial and least-cost option when compared to the Reference Case and most other scenarios. It also shows that all scenarios retiring our nuclear units before their current license expirations would be costlier to customers than the Reference Case. The following Figure shows updated Preferred Plan cost-effectiveness results, on a PVSC basis, from both EnCompass and Strategist modeling.

Figure VIII-2: Scenario PVSC Deltas from Reference Case –EnCompass and Strategist



As in our original filing, the Supplement Preferred Plan (based on Scenario 9) is not the absolute least cost scenario of the 15 options considered; multiple lesser-cost options include a Prairie Island extension. While we are not currently proposing to pursue a Prairie Island license extension at this time – for reasons further discussed below – these results continue to support our initial findings that extending all our nuclear units beyond their existing lives, in conjunction with retiring our coal units early, is in our customers' interests and contributes to achievement of our carbon reduction goals.[75]

b. Action Plan with Respect to Nuclear Units

In order to realize customer benefits from our Supplement Preferred Plan, the Company must begin activities to relicense the Monticello unit within the five-year action plan window. As we discussed in our initial filing, there are two key initial components to achieving Monticello extension that will need to begin between now and the mid-2020s: 1) the NRC's SLR process and 2) a Minnesota Certificate of Need (CN) for additional dry cask fuel storage. Specifically, in this Supplement Preferred Plan's action plan we continue to propose to begin work on the SLR application, which we plan to kick off in mid-2021. We anticipate this work will take approximately two years, which means we would file for SLR approval in early 2023. Concurrently, we plan to begin developing a CN proposal for the Commission this year, which we tentatively plan to file in 2021, and for which we would hope to receive approval in 2023.

As noted above, we are not proposing a Prairie Island extension as part of our Supplement Preferred Plan at this time; rather, we believe deferring a decision on a proposed Prairie Island extension is the best path forward to allow additional time to work with our host communities, while also not precluding us from pursuing customer savings in the future. Scenarios that include extending the license for Prairie Island in addition to Monticello are effectively identical to our Preferred Plan in the first five years. We expect to file our next Resource Plan – covering the 2024-2038 planning period – sometime in 2023. Thus, while we need to begin relicensing approval activities for Monticello in a relatively short timeframe, we have time to reevaluate the potential benefits of Prairie Island extension.

Given the rapidly evolving nature of clean energy technology costs and development, as well as the policy environment in Minnesota and federally, we believe maintaining optionality on a Prairie Island extension is the best path forward. Further, deferring those decisions will provide the Company additional time to engage the Prairie Island

[75] We also note that the benefits of more flexible nuclear operations and potential value of nuclear hydrogen generation have not been factored into our Supplement Preferred Plan analysis. This means that there may be additional customer savings and carbon reduction upside associated with both Monticello and Prairie Island life extension, when accounting for this additional flexibility.

Indian Community, City of Red Wing, and other community interests on the benefits and concerns regarding the plant's life extension. We will, for example, have additional time to work with other utilities and relevant authorities on significant issues of concern, such as an interim spent fuel storage solution discussed previously. We also continue to track nuclear generation technology development, such as design and approval progress on advanced reactor designs discussed in our initial filing.

IX. LOAD AND RESOURCES TABLES

Table IX-1: EnCompass Reference Case (Scenario 1) System Load and Resources, UCAP

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Forecast gross Load	10,502	10,563	10,635	10,711	10,780	10,842	10,911	10,982	11,053	11,119	11,184	11,253	11,324	11,391	11,452
EV Forecast	8	12	17	25	35	44	53	65	79	99	126	163	214	273	336
Forecast EE (reduction in load)	1,395	1,508	1,550	1,625	1,723	1,817	1,907	1,975	2,052	2,189	2,269	2,367	2,448	2,521	2,583
Forecasted Net Load	9,115	9,067	9,101	9,111	9,092	9,068	9,057	9,072	9,080	9,029	9,041	9,049	9,090	9,143	9,205
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Load	8,659	8,614	8,646	8,655	8,638	8,615	8,604	8,618	8,626	8,578	8,589	8,597	8,636	8,686	8,745
MISO PRM	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%
NSP Obligation	9,430	9,380	9,416	9,426	9,406	9,382	9,370	9,385	9,393	9,341	9,354	9,362	9,404	9,459	9,523
Reference Plan - Scenario 1 - UCAP															
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Load Management (existing)	1,012	1,027	1,041	1,055	1,066	1,072	1,077	1,078	1,077	1,071	1,059	1,048	1,037	1,026	1,016
Load Management (potential study)	33	165	232	294	341	382	394	407	423	440	458	478	499	521	545
Coal	2,295	2,295	2,295	2,295	1,647	1,647	1,647	994	994	994	994	994	994	994	994
Nuclear	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,019	1,019	1,019	498	0
Natural Gas/Oil	3,858	3,858	3,858	3,858	3,713	3,403	3,112	2,831	2,831	2,831	2,831	2,288	2,012	2,012	2,012
Sherco CC	0	0	0	0	0	0	0	728	728	728	728	728	728	728	728
Biomass/RDF	110	110	110	86	86	61	61	61	29	29	29	19	19	19	19
Hydro	881	1,001	993	993	993	162	162	162	162	162	162	162	156	152	152
Wind	498	623	672	647	635	631	626	611	605	583	582	566	563	498	479
Grid-Scale Solar	129	129	128	127	122	116	110	105	99	94	88	83	78	73	72
S*R Community Solar	329	357	394	421	409	392	376	359	343	326	309	292	276	259	259
Distributed Solar	37	45	53	60	64	68	71	74	76	78	78	79	78	77	81
Total Existing Resources	10,824	11,252	11,418	11,478	10,717	9,576	9,278	9,052	9,007	8,976	8,338	7,757	7,459	6,857	6,358
Net Resource (Need)/Surplus	1,394	1,871	2,002	2,052	1,311	195	-92	-334	-386	-365	-1,016	-1,605	-1,945	-2,602	-3,166
Future Firm Peaking	0	0	0	0	0	0	0	0	0	0	0	321	642	1,605	1,925
Future Solar	0	0	0	0	0	230	440	420	600	760	1,080	1,190	1,120	1,050	1,050
Future Wind	0	0	0	0	0	0	0	0	0	0	0	125	251	376	501
Total New Resources	0	0	0	0	0	230	440	420	600	760	1,080	1,636	2,012	3,030	3,476
Projected Net Position (Need)/Surplus	1,394	1,871	2,002	2,052	1,311	425	348	86	214	395	64	31	67	429	311

Table IX-2: EnCompass Reference Case (Scenario 1) System Load and Resources, ICAP

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Forecast gross Load	10,502	10,563	10,635	10,711	10,780	10,842	10,911	10,982	11,053	11,119	11,184	11,253	11,324	11,391	11,452
EV Forecast	8	12	17	25	35	44	53	65	79	99	126	163	214	273	336
Forecast EE (reduction in load)	1,395	1,508	1,550	1,625	1,723	1,817	1,907	1,975	2,052	2,189	2,269	2,367	2,448	2,521	2,583
Forecasted Net Load	9,115	9,067	9,101	9,111	9,092	9,068	9,057	9,072	9,080	9,029	9,041	9,049	9,090	9,143	9,205
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Load	8,659	8,614	8,646	8,655	8,638	8,615	8,604	8,618	8,626	8,578	8,589	8,597	8,636	8,686	8,745
MISO PRM	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%
NSP Obligation	9,430	9,380	9,416	9,426	9,406	9,382	9,370	9,385	9,393	9,341	9,354	9,362	9,404	9,459	9,523
								Reference Plan - Scenario 1 - ICAP							
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Load Management (existing)	1,048	1,063	1,078	1,092	1,103	1,108	1,113	1,114	1,113	1,108	1,096	1,084	1,073	1,063	1,052
Load Management (potential study)	34	168	236	299	346	388	401	414	430	447	466	486	507	529	553
Coal	2,390	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	1,028	1,028	1,028	1,028	1,028
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,092	1,092	1,092	546
Natural Gas/Oil	4,735	4,735	4,735	4,735	4,735	4,544	4,186	3,811	3,505	3,505	3,505	2,726	2,726	2,428	2,428
Sherco CC	0	0	0	0	0	0	0	835	835	835	835	835	835	835	835
Biomass/RDF	141	137	137	135	111	77	77	77	42	42	42	27	27	27	27
Hydro	687	806	792	792	792	742	292	291	291	291	291	291	282	282	278
Wind	3,766	4,215	4,206	4,056	3,971	3,964	3,921	3,790	3,782	3,622	3,569	3,542	3,434	2,811	2,709
Grid-Scale Solar	258	257	256	254	253	252	251	249	248	247	246	244	243	242	241
S*R Community Solar	658	714	787	841	852	853	854	855	857	858	859	860	861	862	863
Distributed Solar	83	98	112	126	140	154	169	183	197	210	224	238	251	265	277
Total Existing Resources	15,537	16,322	16,467	16,459	16,431	15,529	14,709	15,066	14,066	13,931	13,899	12,453	12,360	11,464	10,837
Net Resource (Need)/Surplus	6,107	6,941	7,051	7,033	7,025	6,147	5,339	5,681	4,673	4,590	4,545	3,092	2,956	2,005	1,314
Future Firm Peaking	0	0	0	0	0	0	0	0	0	0	0	374	748	1,870	2,244
Future Solar	0	0	0	0	0	500	1,000	1,000	1,500	2,000	3,000	3,500	3,500	3,500	3,500
Future Wind	0	0	0	0	0	0	0	0	0	0	0	750	1,500	2,250	3,000
Total New Resources	0	0	0	0	0	500	1,000	1,000	1,500	2,000	3,000	4,624	5,748	7,620	8,744
Projected Net Position (Need)/Surplus	6,107	6,941	7,051	7,033	7,025	6,647	6,339	6,681	6,173	6,590	7,545	7,716	8,704	9,625	10,058

Table IX-3: EnCompass Supplement Preferred Plan (Scenario 9) System Load and Resources, UCAP

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Forecast gross Load	10,502	10,563	10,635	10,711	10,780	10,842	10,911	10,982	11,053	11,119	11,184	11,253	11,324	11,391	11,452
EV Forecast	8	12	17	25	35	44	53	65	79	99	126	163	214	273	336
Forecast EE (reduction in load)	1,395	1,508	1,550	1,625	1,723	1,817	1,907	1,975	2,052	2,189	2,269	2,367	2,448	2,521	2,583
Forecasted Net Load	9,115	9,067	9,101	9,111	9,092	9,068	9,057	9,072	9,080	9,029	9,041	9,049	9,090	9,143	9,205
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Load	8,659	8,614	8,646	8,655	8,638	8,615	8,604	8,618	8,626	8,578	8,589	8,597	8,636	8,686	8,745
MISO PRM	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%
NSP Obligation	9,430	9,380	9,416	9,426	9,406	9,382	9,370	9,385	9,393	9,341	9,354	9,362	9,404	9,459	9,523
	Supplement Preferred Plan - Scenario 9 - UCAP														
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Load Management (existing)	1,012	1,027	1,041	1,055	1,066	1,072	1,077	1,078	1,077	1,071	1,059	1,048	1,037	1,026	1,016
Load Management (potential study)	33	165	232	294	341	382	394	407	423	440	458	478	499	521	545
Coal	2,295	2,295	2,295	2,295	1,647	1,647	1,647	994	994	511	0	0	0	0	0
Nuclear	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,120	622
Natural Gas/Oil	3,858	3,858	3,858	3,858	3,713	3,403	3,112	2,831	2,831	2,831	2,831	2,288	2,012	2,012	2,012
Sherco CC	0	0	0	0	0	0	0	728	728	728	728	728	728	728	728
Biomass/RDF	110	110	110	86	86	61	61	61	29	29	29	19	19	19	19
Hydro	881	1,001	993	993	993	162	162	162	162	162	162	162	156	152	152
Wind	498	623	672	647	635	631	626	611	605	583	582	566	563	498	479
Grid-Scale Solar	129	129	128	127	122	116	110	105	99	94	88	83	78	73	72
S*R Community Solar	329	357	394	421	409	392	376	359	343	326	309	292	276	259	259
Distributed Solar	37	45	53	60	64	68	71	74	76	78	78	79	78	77	81
Total Existing Resources	10,824	11,252	11,418	11,478	10,717	9,576	9,278	9,052	9,007	8,493	7,967	7,386	7,087	6,486	5,986
Net Resource (Need)/Surplus	1,394	1,871	2,002	2,052	1,311	195	-92	-334	-386	-848	-1,387	-1,976	-2,317	-2,973	-3,537
Future Firm Peaking	0	0	0	0	0	0	0	0	0	0	321	963	1,284	1,925	2,246
Future Solar	0	0	0	0	0	230	440	420	600	950	1,260	1,190	1,120	1,050	1,050
Future Wind	0	0	0	0	0	0	0	0	0	0	0	0	125	251	376
Total New Resources	0	0	0	0	0	230	440	420	600	950	1,581	2,153	2,529	3,226	3,672
Projected Net Position (Need)/Surplus	1,394	1,871	2,002	2,052	1,311	425	348	86	214	102	194	176	212	253	135

Table IX-4: EnCompass Supplement Preferred Plan (Scenario 9) System Load and Resources, ICAP

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Forecast gross Load	10,502	10,563	10,635	10,711	10,780	10,842	10,911	10,982	11,053	11,119	11,184	11,253	11,324	11,391	11,452
EV Forecast	8	12	17	25	35	44	53	65	79	99	126	163	214	273	336
Forecast EE (reduction in load)	1,395	1,508	1,550	1,625	1,723	1,817	1,907	1,975	2,052	2,189	2,269	2,367	2,448	2,521	2,583
Forecasted Net Load	9,115	9,067	9,101	9,111	9,092	9,068	9,057	9,072	9,080	9,029	9,041	9,049	9,090	9,143	9,205
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Load	8,659	8,614	8,646	8,655	8,638	8,615	8,604	8,618	8,626	8,578	8,589	8,597	8,636	8,686	8,745
MISO PRM	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%
NSP Obligation	9,430	9,380	9,416	9,426	9,406	9,382	9,370	9,385	9,393	9,341	9,354	9,362	9,404	9,459	9,523
							Supplement Preferred Plan - Scenario 9 - ICAP								
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Load Management (existing)	1,048	1,063	1,078	1,092	1,103	1,108	1,113	1,114	1,113	1,108	1,096	1,084	1,073	1,063	1,052
Load Management (potential study)	34	168	236	299	346	388	401	414	430	447	466	486	507	529	553
Coal	2,390	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	517	0	0	0	0
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,192
Natural Gas/Oil	4,735	4,735	4,735	4,735	4,735	4,544	4,186	3,811	3,505	3,505	3,505	2,726	2,726	2,428	2,428
Sherco CC	0	0	0	0	0	0	0	835	835	835	835	835	835	835	835
Biomass/RDF	141	137	137	135	111	77	77	77	42	42	42	27	27	27	27
Hydro	687	806	792	792	792	742	292	291	291	291	291	291	282	282	278
Wind	3,766	4,215	4,206	4,056	3,971	3,969	3,921	3,790	3,782	3,622	3,569	3,542	3,434	2,811	2,709
Grid-Scale Solar	258	257	256	254	253	252	251	249	248	247	246	244	243	242	241
S*R Community Solar	658	714	787	841	852	853	854	855	857	858	859	860	861	862	863
Distributed Solar	83	98	112	126	140	154	169	183	197	210	224	238	251	265	277
Total Existing Resources	15,537	16,322	16,467	16,459	16,431	15,534	14,709	15,066	14,066	13,931	13,388	12,071	11,978	11,082	10,455
Net Resource (Need)/Surplus	6,107	6,941	7,051	7,033	7,025	6,152	5,339	5,681	4,673	4,590	4,034	2,710	2,574	1,623	932
Future Firm Peaking	0	0	0	0	0	0	0	0	0	0	374	1,122	1,496	2,244	2,618
Future Solar	0	0	0	0	0	500	1,000	1,000	1,500	2,500	3,500	3,500	3,500	3,500	3,500
Future Wind	0	0	0	0	0	0	0	0	0	0	0	0	750	1,500	2,250
Total New Resources	0	0	0	0	0	500	1,000	1,000	1,500	2,500	3,874	4,622	5,746	7,244	8,368
Projected Net Position (Need)/Surplus	6,107	6,941	7,051	7,033	7,025	6,652	6,339	6,681	6,173	7,090	7,908	7,332	8,320	8,867	9,300

X. MODELING SCENARIO SENSITIVITY ANALYSIS – PVRR AND PVSC SUMMARY

In the course of Supplement modeling, the Company conducted several hundred modeling runs testing how different assumptions affect capacity expansion portfolio and cost outcomes. We discuss several of these in Section II. Modeling Framework and Results but include here a description and results from additional sensitivity testing runs. These runs and results fall into two primary categories; A) individual sensitivities conducted on all 15 baseload scenarios, and B) alternate sensitivities conducted on only the Reference Case and Supplement Preferred Plan.

A. Individual Sensitivities

As noted above, the Company tested several sensitivities on our baseload scenarios; these individual sensitivities vary one input at a time in order to isolate the effect of those changes on capacity expansion plans and net present value cost/savings. These represent the "standard" set of individual sensitivities we used in our initial July 2019 filing and across many other dockets that examine the economic effects of proposed resource acquisitions. They include:

- *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.
- *CO2 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.[76] The PVSC Base Case values starting in 2025 are based on the "high" end of the range of regulated costs. Below is the list of carbon sensitivities.
    - Low Externality
    - Low Externality, Low Regulatory

[76] Minnesota Commission Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.) at 31.

- 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,[77] 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 2019 ATB report to provide high and low technology cost sensitivity inputs. We use these cost forecasts directly in our sensitivity analysis, with adjustments for interconnection costs as needed. 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 Interactions* – Assumptions regarding MISO market sales and purchases have become increasingly important as we integrate higher levels of renewable resources on to our system. By participating in MISO, we can take advantage of an efficient market to make sales into the larger MISO footprint when our production exceeds our native load requirements, and purchases when market prices are lower than the cost of our generators. The addition of our 1,550 MW wind portfolio[78] and other recent wind resource additions will create a significant amount of energy that exceeds the needs of our native load. For 2022, when the recent wind additions will be fully operational, our Supplement Preferred Plan results show 11,600 GWh of sales into the MISO market. In previous Strategist modeling, we included a "no markets" sensitivity, where market interactions were not allowed. This sensitivity was designed to provide insight into whether a resource was being added to serve native load or was reliant on the ability to utilize the MISO market. However, with the recent wind additions to our system, we do not believe a "no markets" sensitivity provides useful results. Without the availability of the market, the models treat any energy in excess of load as "dump" energy, and the recently approved wind portfolio creates a significant amount of dump energy in all scenarios when markets are turned off. If markets are not available, the model will try to solve

[77] Minnesota Commission Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.
[78] Per Docket No. E002/M-16-777.

the "dump" energy problem, by finding an expansion plan that can better incorporate use of that energy, often with unexpected or unrealistic results, instead of considering that the excess energy would likely be sold into the market and not actually be "valueless."

- *Market Sensitivities* In the base modeling, an adder for the regulatory cost of carbon is placed on the locational marginal price (LMP) in the market for both purchases and sales using the forecasted annual average MISO emissions rate. We note that this assumption could have the effect of increasing the sales from our dispatchable generation if the market price on sales exceeds the dispatch costs. Therefore, we created two additional sensitivities to address this concern and to better address the risk related to market assumptions. First, we included a sensitivity with no carbon adder on market sales. This sensitivity will reduce the price for sales into the market and therefore, the risk that a dispatchable unit with be utilized due to the inclusion of the carbon adder. Second, we included a sensitivity that shapes the carbon adder based on the implied heat rate of the LMP for each hour. By shaping to the implied heat rate of the LMP, this carbon adder assumption is intended to better reflect the carbon intensity of the marginal unit on the MISO system. We also note that, as in our initial filing, we have run high and low fuel and market price sensitivities. We acknowledge that assumptions related to market interactions will need further refinement as markets evolve and more renewable resources are added. We are open to working with the Department and other stakeholders to develop further analysis in this Resource Plan or subsequent proceedings related to market interactions.

B. Alternate Assumptions Sensitivities

We also tested several alternate assumption sensitivities to provide estimates of the impacts of assumptions or constraints we changed in modeling since our initial filing. We ran these alternate sensitivities on the Supplement Preferred Plan only. These include:

- *Early wind availability*. Our base assumptions constrain the model from selecting wind resources prior to 2026, to reflect MISO transmission interconnection queue constraints. This sensitivity relaxes this constraint and allows the models to select generic wind resources starting in 2023. Our analysis found that this assumption had no influence on the results, as neither Strategist or EnCompass modeling selected any early availability wind.

- *Solar ELCC.* Our base assumptions include a solar ELCC values that declines from 50 percent to 30 percent between 2023-2033. This alternate sensitivity examined the effect of maintaining a 50 percent ELCC throughout the modeling period. As expected, a higher capacity accreditation value results in the models selecting more solar at an overall lower portfolio cost. That said, we believe a declining ELCC assumption is consistent with MISO and other utilities' long-term planning approaches and more appropriately reflects the reality of solar resources' ability to meet capacity needs in markets with increasing solar adoption.
- *Unconstrained sales/purchases.* Our base assumptions enforce a market sales constraint equal to 25 percent of retail sales in a given year in the course of capacity expansion modeling in EnCompass.[79] In this sensitivity, this constraint is relaxed in EnCompass, in both the capacity expansion and production costing model runs. The results of this sensitivity show higher costs than the Supplement Preferred Plan, indicating that – given the simplifying assumptions used in the capacity expansion runs – the model selected more resources that received lower market revenue than expected when analyzed in production costing runs, and thus cost to customers increased. This indicates that an unconstrained market sales assumption leads EnCompass to overvalue incremental resources.
- *DR and EE bundles.* In the EnCompass modeling, the first DR bundle and the first two EE bundles were included in our baseline modeling, and the remaining bundles were not made available for the model to select in the optimization. As in our initial filing, we took this approach to reduce model complexity and improve runtimes. However, to test this assumption, we ran alternate sensitivities that individually forced-in the next EE and DR bundles to test whether the PVSC and PVRR results indicate either option would be cost effective relative to other resource options. The results confirmed that incremental bundles of EE and/or DR were not cost effective in the EnCompass modeling results.

[79] Note that we did not enforce the same constraint in Strategist as it does not have the ability to constrain market sales.

ENCOMPASS RESULTS

Table X-1: EnCompass Net Present Value Results for Baseload Scenarios PVSC and PVRR, and Sensitivities B-I

Parent Run	Description	Base - PVSC	A-PVRR	B-Low Gas/Coal/ Markets	C-High Gas/Coal/ Markets	D-Low Load (High DER)	E-High Load (Electrification)	F-Low Resource Cost	G-High Resource Cost	I-Low Externality
Scenario 1	*REFERENCE*	$41,050	$37,479	$40,928	$41,165	$41,793	$43,659	$39,591	$43,178	$39,071
Scenario 2	*EARLY KING*	$40,980	$37,436	$40,867	$41,084	$41,749	$43,628	$39,505	$43,125	$38,964
Scenario 3	*EARLY SH3*	$40,943	$37,604	$40,842	$41,006	$41,658	$43,561	$39,416	$43,185	$39,044
Scenario 4	*EARLY COAL*	$40,859	$37,571	$40,779	$40,898	$41,629	$43,550	$39,307	$43,120	$38,935
Scenario 5	*EARLY MONTI*	$41,163	$37,487	$41,018	$41,303	$41,906	$43,732	$39,634	$43,338	$39,098
Scenario 6	*EARLY PI*	$41,619	$37,765	$41,445	$41,788	$42,298	$44,198	$39,905	$44,031	$39,428
Scenario 7	*EARLY All NUCLEAR*	$41,655	$37,600	$41,431	$41,881	$42,412	$44,339	$39,879	$44,119	$39,326
Scenario 8	*EARLY BASELOAD*	$41,583	$37,660	$41,335	$41,815	$42,398	$44,160	$39,887	$43,903	$39,156
Scenario 9	*EARLY COAL; EXTEND MONTI*	$40,823	$37,563	$40,743	$40,863	$41,571	$43,470	$39,474	$42,772	$38,910
Scenario 10	*EARLY KING; EXTEND MONTI*	$40,952	$37,429	$40,852	$41,035	$41,665	$43,526	$39,643	$42,849	$38,951
Scenario 11	*EARLY COAL; EXTEND PI*	$40,468	$37,234	$40,431	$40,443	$41,280	$43,120	$39,148	$42,339	$38,589
Scenario 12	*EARLY COAL; EXTEND All NUCLEAR*	$40,493	$37,274	$40,479	$40,438	$41,256	$43,110	$39,352	$42,130	$38,654
Scenario 13	*EXTEND MONTI*	$41,020	$37,480	$40,923	$41,099	$41,838	$43,591	$39,689	$42,962	$39,067
Scenario 14	*EXTEND PI*	$40,648	$37,110	$40,589	$40,672	$41,470	$43,316	$39,371	$42,468	$38,724
Scenario 15	*EXTEND All NUCLEAR*	$40,675	$37,209	$40,641	$40,670	$41,477	$43,240	$39,576	$42,241	$38,804

The numbers above represent 2020-2045 total net present value (NPV) costs.

Table X-2: EnCompass Net Present Value Deltas for Baseload Scenarios PVSC and PVRR, and Sensitivities B-I

Parent Run	Description	Base - PVSC	A-PVRR	B-Low Gas/Coal/ Markets	C-High Gas/Coal/ Markets	D-Low Load (High DER)	E-High Load (Electrification)	F-Low Resource Cost	G-High Resource Cost	I-Low Externality
Scenario 1	*REFERENCE*	$0	$0	$0	$0	$0	$0	$0	$0	$0
Scenario 2	*EARLY KING*	($70)	($44)	($60)	($81)	($44)	($32)	($86)	($52)	($108)
Scenario 3	*EARLY SH3*	($108)	$124	($86)	($159)	($134)	($99)	($175)	$7	($27)
Scenario 4	*EARLY COAL*	($191)	$92	($149)	($267)	($163)	($110)	($284)	($57)	($136)
Scenario 5	*EARLY MONTI*	$112	$8	$90	$138	$113	$73	$43	$160	$27
Scenario 6	*EARLY PI*	$569	$286	$517	$623	$505	$539	$314	$854	$357
Scenario 7	*EARLY All NUCLEAR*	$605	$121	$503	$716	$619	$680	$288	$942	$255
Scenario 8	*EARLY BASELOAD*	$533	$181	$407	$650	$605	$501	$296	$725	$85
Scenario 9	*EARLY COAL; EXTEND MONTI*	($228)	$83	($185)	($302)	($222)	($189)	($117)	($406)	($161)
Scenario 10	*EARLY KING; EXTEND MONTI*	($99)	($50)	($75)	($130)	($128)	($133)	$52	($329)	($121)
Scenario 11	*EARLY COAL; EXTEND PI*	($582)	($245)	($497)	($722)	($513)	($539)	($443)	($838)	($483)
Scenario 12	*EARLY COAL; EXTEND All NUCLEAR*	($557)	($206)	($449)	($727)	($537)	($549)	($240)	($1,048)	($418)
Scenario 13	*EXTEND MONTI*	($30)	$1	($5)	($66)	$45	($68)	$98	($216)	($5)
Scenario 14	*EXTEND PI*	($402)	($370)	($339)	($493)	($322)	($344)	($220)	($709)	($347)
Scenario 15	*EXTEND All NUCLEAR*	($375)	($270)	($287)	($495)	($316)	($419)	($15)	($937)	($268)

The deltas above were derived by comparing the total NPV costs of each scenario to the Reference Case/Scenario 1.

Table X-3: EnCompass Net Present Value Results for Baseload Scenario Sensitivities J-V

Parent Run	Description	J-Low Externality, Low Regulatory	K-Mid Externality, Mid Regulatory	L-High Externality	M-No Reg or Externality Costs	P - Combo "DBF"	Q - Combo "ECF"	S - No Carbon Adder for Sales	U - Hourly Carbon, Retail Load Shape	V - Optimize with Externality in model
Scenario 1	*REFERENCE*	$38,248	$39,667	$45,052	$37,196	$40,919	$42,950	$44,122	$40,956	$39,175
Scenario 2	*EARLY KING*	$38,192	$39,599	$44,699	$37,171	$40,825	$42,887	$44,208	$40,878	$39,058
Scenario 3	*EARLY SH3*	$38,287	$39,630	$44,606	$37,330	$40,769	$42,765	$44,276	$40,879	$39,012
Scenario 4	*EARLY COAL*	$38,234	$39,558	$44,221	$37,313	$40,609	$42,559	$44,191	$40,762	$38,936
Scenario 5	*EARLY MONTI*	$38,289	$39,743	$45,108	$37,215	$41,061	$43,096	$44,422	$41,103	$39,223
Scenario 6	*EARLY PI*	$38,617	$40,135	$45,569	$37,506	$40,578	$43,364	$44,956	$41,558	$39,660
Scenario 7	*EARLY All NUCLEAR*	$38,516	$40,102	$45,608	$37,361	$40,681	$43,483	$44,961	$41,624	$39,768
Scenario 8	*EARLY BASELOAD*	$38,465	$40,035	$44,890	$37,404	$40,928	$43,209	$44,844	$41,560	$39,664
Scenario 9	*EARLY COAL; EXTEND MONTI*	$38,205	$39,526	$44,203	$37,286	$40,702	$42,484	$44,111	$40,731	$38,914
Scenario 10	*EARLY KING; EXTEND MONTI*	$38,176	$39,577	$44,688	$37,158	$40,861	$42,688	$44,139	$40,859	$39,029
Scenario 11	*EARLY COAL; EXTEND PI*	$37,881	$39,186	$43,862	$36,970	$39,883	$41,099	$43,350	$40,432	$38,586
Scenario 12	*EARLY COAL; EXTEND All NUCLEAR*	$37,936	$39,226	$43,937	$37,032	$40,262	$41,118	$43,217	$40,456	$38,582
Scenario 13	*EXTEND MONTI*	$38,238	$39,647	$45,053	$37,190	$40,989	$42,897	$44,048	$40,955	$39,101
Scenario 14	*EXTEND PI*	$37,893	$39,288	$44,694	$36,852	$40,142	$41,282	$43,431	$40,599	$38,718
Scenario 15	*EXTEND All NUCLEAR*	$37,964	$39,338	$44,761	$36,935	$40,533	$41,496	$43,542	$40,623	$38,729

The numbers above represent 2020-2045 total NPV costs.

Table X-4: EnCompass Net Present Value Deltas for Baseload Scenario Sensitivities J-V

Parent Run	Description	J-Low Externality, Low Regulatory	K-Mid Externality, Mid Regulatory	L-High Externality	M-No Reg or Externality Costs	P - Combo "DBF"	Q - Combo "ECF"	S - No Carbon Adder for Sales	U - Hourly Carbon, Retail Load Shape	V - Optimize with Externality in model
Scenario 1	*REFERENCE*	$0	$0	$0	$0	$0	$0	$0	$0	$0
Scenario 2	*EARLY KING*	($56)	($68)	($353)	($25)	($94)	($64)	$85	($78)	($116)
Scenario 3	*EARLY SH3*	$39	($37)	($446)	$133	($151)	($185)	$153	($77)	($163)
Scenario 4	*EARLY COAL*	($14)	($109)	($831)	$117	($311)	($391)	$68	($194)	($239)
Scenario 5	*EARLY MONTI*	$41	$76	$56	$19	$141	$146	$299	$147	$48
Scenario 6	*EARLY PI*	$369	$468	$517	$310	($341)	$414	$834	$602	$485
Scenario 7	*EARLY All NUCLEAR*	$268	$435	$556	$165	($239)	$533	$839	$668	$593
Scenario 8	*EARLY BASELOAD*	$216	$368	($162)	$208	$9	$259	$722	$604	$489
Scenario 9	*EARLY COAL; EXTEND MONTI*	($43)	($141)	($849)	$90	($218)	($467)	($11)	($225)	($261)
Scenario 10	*EARLY KING; EXTEND MONTI*	($72)	($90)	($364)	($38)	($59)	($262)	$17	($97)	($145)
Scenario 11	*EARLY COAL; EXTEND PI*	($367)	($481)	($1,190)	($226)	($1,037)	($1,851)	($772)	($524)	($589)
Scenario 12	*EARLY COAL; EXTEND All NUCLEAR*	($312)	($441)	($1,114)	($164)	($658)	($1,833)	($905)	($500)	($593)
Scenario 13	*EXTEND MONTI*	($10)	($20)	$1	($6)	$69	($54)	($74)	($1)	($74)
Scenario 14	*EXTEND PI*	($355)	($379)	($358)	($344)	($777)	($1,668)	($691)	($357)	($457)
Scenario 15	*EXTEND All NUCLEAR*	($284)	($329)	($291)	($261)	($387)	($1,454)	($581)	($333)	($445)

The deltas above were derived by comparing the total NPV costs of each baseload scenario to the Reference Case/Scenario 1.

Table X-5: EnCompass Net Present Value Results for North Dakota Scenario and Preferred Plan Sensitivities

Child Runs	Description	Base - PVSC	A-PVRR	I-Low Externality	J-Low Externality, Low Regulatory	K-Mid Externality, Mid Regulatory	L-High Externality	M-No Reg or Externality Costs
Scenario 1	Supplement North Dakota Scenario		$36,750					
Scenario 9	Supplement North Dakota Scenario		$36,949					
Scenario 9	EARLY COAL; EXTEND MONTI	$40,823	$37,563	$38,910	$38,205	$39,526	$44,203	$37,286
Scenario 9	Wind Available 2023 @ $500/kW	$40,812	$37,572					
Scenario 9	Solar @ 50% ELCC Throughout	$40,277	$36,769					
Scenario 9	Unconstrained Sales/Purchase Volume	$40,844	$37,721					
Scenario 9	Sherco CC Alternatives - 7HA01 1x1	$41,015	$37,796	$39,102	$38,444	$39,742	$44,185	$37,534
Scenario 9	Sherco CC Alternatives - 7HA02 1x1	$40,855	$37,600	$38,948	$38,275	$39,577	$44,091	$37,365
Scenario 9	Sherco CC Alternatives - 7HA02 2x1	$40,474	$37,209	$38,610	$37,857	$39,178	$44,077	$36,939
Scenario 9	Solar + Storage: "swap" 1st solar addition	$40,851	$37,607	$38,975	$38,270	$39,572	$44,232	$37,360
Scenario 9	Wind + Storage: "swap" 1st wind addition	$41,034	$37,744	$39,112	$38,401	$39,729	$44,440	$37,477
Scenario 9	DSM/DR - Add DR Bundle 2	$40,860	$37,588	$38,946	$38,243	$39,563	$44,231	$37,323
Scenario 9	DSM/DR - Add EE Bundle 3	$41,491	$38,342	$39,725	$39,021	$40,334	$45,000	$38,108

The numbers above represent 2020-2045 total NPV costs.

Table X-6: EnCompass Net Present Value Deltas for North Dakota Scenario and Preferred Plan Sensitivities

Child Runs	Description	Base - PVSC	A-PVRR	I-Low Externality	J-Low Externality, Low Regulatory	K-Mid Externality, Mid Regulatory	L-High Externality	M-No Reg or Externality Costs
Scenario 1	Supplement North Dakota Scenario		$0					
Scenario 9	Supplement North Dakota Scenario		$199					
Scenario 9	EARLY COAL; EXTEND MONTI	$0	$0	$0	$0	$0	$0	$0
Scenario 9	Wind Available 2023 @ $500/kW	($11)	$9					
Scenario 9	Solar @ 50% ELCC Throughout	($545)	($793)					
Scenario 9	Unconstrained Sales/Purchase Volume	$21	$159					
Scenario 9	Sherco CC Alternatives - 7HA01 1x1	$193	$234	$192	$239	$216	($18)	$249
Scenario 9	Sherco CC Alternatives - 7HA02 1x1	$32	$38	$38	$70	$51	($112)	$79
Scenario 9	Sherco CC Alternatives - 7HA02 2x1	($349)	($353)	($300)	($348)	($348)	($126)	($347)
Scenario 9	Solar + Storage: "swap" 1st solar addition	$29	$44	$65	$65	$46	$29	$74
Scenario 9	Wind + Storage: "swap" 1st wind addition	$212	$182	$202	$196	$203	$237	$191
Scenario 9	DSM/DR - Add DR Bundle 2	$37	$26	$36	$38	$38	$28	$38
Scenario 9	DSM/DR - Add EE Bundle 3	$668	$780	$815	$816	$808	$797	$822

The Supplement North Dakota Scenario deltas above were derived by comparing the total NPV costs of each scenario to Scenario 1 Supplement North Dakota Scenario. All other deltas were derived by comparing the total NPV costs of each Scenario 9 sensitivity to Scenario 9 – Early Coal; Extend Monti.

STRATEGIST RESULTS

Table X-7: Strategist Net Present Value Results for Baseload Scenarios PVSC and PVRR, and Sensitivities B-I

Parent Run	Description	Base - PVSC	A-PVRR	B-Low Gas/Coal/ Markets	C-High Gas/Coal/ Markets	D-Low Load (High DER)	E-High Load (Electrification)	F-Low Resource Cost	G-High Resource Cost	I-Low Externality
Scenario 1	*REFERENCE*	$43,082	$37,624	$42,736	$43,516	$43,821	$45,557	$41,468	$45,094	$40,604
Scenario 2	*EARLY KING*	$43,003	$37,729	$42,715	$43,373	$43,722	$45,482	$41,317	$45,080	$40,507
Scenario 3	*EARLY SH3*	$43,058	$37,977	$42,754	$43,429	$43,756	$45,488	$41,258	$45,330	$40,731
Scenario 4	*EARLY COAL*	$42,968	$37,817	$42,621	$43,405	$43,724	$45,423	$41,189	$45,210	$40,339
Scenario 5	*EARLY MONTI*	$43,250	$37,590	$42,814	$43,799	$43,930	$45,757	$41,665	$45,197	$40,567
Scenario 6	*EARLY PI*	$43,668	$37,758	$43,143	$44,328	$44,334	$46,128	$41,942	$45,731	$40,696
Scenario 7	*EARLY All NUCLEAR*	$43,774	$37,719	$43,202	$44,483	$44,427	$46,239	$42,062	$45,810	$40,672
Scenario 8	*EARLY BASELOAD*	$43,526	$37,754	$42,922	$44,283	$44,225	$46,027	$41,777	$45,535	$40,256
Scenario 9	*EARLY COAL; EXTEND MONTI*	$42,818	$37,896	$42,608	$43,061	$43,546	$45,288	$41,265	$44,756	$40,481
Scenario 10	*EARLY KING; EXTEND MONTI*	$42,944	$37,827	$42,784	$43,127	$43,681	$45,411	$41,392	$44,923	$40,644
Scenario 11	*EARLY COAL; EXTEND PI*	$42,544	$37,562	$42,333	$42,780	$43,268	$44,970	$40,955	$44,526	$40,095
Scenario 12	*EARLY COAL; EXTEND All NUCLEAR*	$42,414	$37,600	$42,297	$42,518	$43,155	$44,867	$41,072	$44,053	$40,188
Scenario 13	*EXTEND MONTI*	$43,044	$37,674	$42,755	$43,398	$43,811	$45,516	$41,623	$44,849	$40,670
Scenario 14	*EXTEND PI*	$42,650	$37,367	$42,440	$42,878	$43,403	$45,104	$41,242	$44,416	$40,360
Scenario 15	*EXTEND All NUCLEAR*	$42,644	$37,443	$42,489	$42,799	$43,430	$45,080	$41,389	$44,219	$40,443

The numbers above represent 2020-2045 total NPV costs.

Table X-8: Strategist Net Present Value Deltas for Baseload Scenarios PVSC and PVRR, and Sensitivities B-I

Parent Run	Description	Base - PVSC	A-PVRR	B-Low Gas/Coal/ Markets	C-High Gas/Coal/ Markets	D-Low Load (High DER)	E-High Load (Electrification)	F-Low Resource Cost	G-High Resource Cost	I-Low Externality
Scenario 1	*REFERENCE*	$0	$0	$0	$0	$0	$0	$0	$0	$0
Scenario 2	*EARLY KING*	($78)	$105	($21)	($143)	($100)	($75)	($152)	($14)	($97)
Scenario 3	*EARLY SH3*	($23)	$353	$18	($87)	($66)	($70)	($210)	$236	$127
Scenario 4	*EARLY COAL*	($114)	$193	($115)	($112)	($97)	($134)	($280)	$116	($264)
Scenario 5	*EARLY MONTI*	$169	($34)	$79	$282	$109	$200	$196	$103	($37)
Scenario 6	*EARLY PI*	$587	$134	$407	$812	$512	$570	$474	$636	$92
Scenario 7	*EARLY All NUCLEAR*	$692	$95	$466	$966	$606	$681	$594	$715	$68
Scenario 8	*EARLY BASELOAD*	$445	$130	$187	$766	$404	$469	$309	$441	($348)
Scenario 9	*EARLY COAL; EXTEND MONTI*	($264)	$272	($128)	($455)	($276)	($269)	($203)	($338)	($123)
Scenario 10	*EARLY KING; EXTEND MONTI*	($138)	$202	$48	($389)	($141)	($146)	($77)	($171)	$40
Scenario 11	*EARLY COAL; EXTEND PI*	($537)	($62)	($402)	($737)	($554)	($587)	($513)	($569)	($509)
Scenario 12	*EARLY COAL; EXTEND All NUCLEAR*	($668)	($25)	($438)	($999)	($667)	($691)	($397)	($1,042)	($416)
Scenario 13	*EXTEND MONTI*	($38)	$49	$19	($118)	($10)	($42)	$154	($245)	$66
Scenario 14	*EXTEND PI*	($431)	($257)	($296)	($638)	($419)	($453)	($226)	($678)	($243)
Scenario 15	*EXTEND All NUCLEAR*	($438)	($181)	($247)	($717)	($392)	($478)	($80)	($875)	($161)

The deltas above were derived by comparing the total NPV costs of each baseload scenario to the Reference Case/Scenario 1.

Table X-9: Strategist Net Present Value Results for Baseload Sensitivities J-U

Parent Run	Description	J-Low Externality, Low Regulatory	K-Mid Externality, Mid Regulatory	L-High Externality	M-No Reg or Externality Costs	P - Combo "DBF"	Q - Combo "ECF"	S - No Carbon Adder for Sales	U - Hourly Carbon, Retail Load Shape
Scenario 1	*REFERENCE*	$38,524	$41,016	$51,035	$37,447	$41,912	$43,203	$43,105	$43,006
Scenario 2	*EARLY KING*	$38,586	$40,997	$50,334	$37,548	$41,788	$43,002	$43,047	$42,924
Scenario 3	*EARLY SH3*	$38,815	$41,107	$50,567	$37,788	$41,846	$43,110	$43,033	$42,973
Scenario 4	*EARLY COAL*	$38,680	$40,980	$49,464	$37,622	$41,672	$42,893	$42,970	$42,890
Scenario 5	*EARLY MONTI*	$38,534	$41,105	$51,017	$37,401	$41,948	$43,459	$43,123	$43,174
Scenario 6	*EARLY PI*	$38,793	$41,429	$50,978	$37,578	$42,177	$43,832	$43,274	$43,588
Scenario 7	*EARLY All NUCLEAR*	$38,783	$41,476	$51,036	$37,527	$42,226	$43,882	$43,239	$43,690
Scenario 8	*EARLY BASELOAD*	$38,812	$41,302	$49,254	$37,570	$41,946	$43,543	$43,001	$43,434
Scenario 9	*EARLY COAL; EXTEND MONTI*	$38,687	$40,923	$49,813	$37,706	$41,791	$42,836	$42,961	$42,734
Scenario 10	*EARLY KING; EXTEND MONTI*	$38,629	$41,000	$50,619	$37,642	$41,989	$43,036	$43,144	$42,863
Scenario 11	*EARLY COAL; EXTEND PI*	$38,375	$40,624	$49,255	$37,369	$41,638	$42,488	$42,701	$42,463
Scenario 12	*EARLY COAL; EXTEND All NUCLEAR*	$38,359	$40,564	$49,523	$37,413	$41,791	$42,440	$42,743	$42,319
Scenario 13	*EXTEND MONTI*	$38,535	$41,009	$51,201	$37,483	$42,295	$43,530	$43,203	$42,966
Scenario 14	*EXTEND PI*	$38,211	$40,652	$50,863	$37,183	$41,878	$42,790	$42,840	$42,571
Scenario 15	*EXTEND All NUCLEAR*	$38,257	$40,676	$50,982	$37,255	$42,173	$42,938	$42,992	$42,559

The numbers in the table above represent 2020-2045 total net present value (NPV) costs.

Table X-10: Strategist Net Present Value Deltas for Baseload Sensitivities J-U

Parent Run	Description	J-Low Externality, Low Regulatory	K-Mid Externality, Mid Regulatory	L-High Externality	M-No Reg or Externality Costs	P - Combo "DBF"	Q - Combo "ECF"	S - No Carbon Adder for Sales	U - Hourly Carbon, Retail Load Shape
Scenario 1	*REFERENCE*	$0	$0	$0	$0	$0	$0	$0	$0
Scenario 2	*EARLY KING*	$62	($19)	($701)	$101	($124)	($201)	($59)	($83)
Scenario 3	*EARLY SH3*	$290	$91	($468)	$342	($65)	($93)	($72)	($33)
Scenario 4	*EARLY COAL*	$156	($36)	($1,571)	$176	($239)	($310)	($135)	($117)
Scenario 5	*EARLY MONTI*	$10	$89	($18)	($46)	$36	$256	$18	$168
Scenario 6	*EARLY PI*	$269	$413	($57)	$131	$265	$630	$169	$582
Scenario 7	*EARLY All NUCLEAR*	$258	$460	$1	$80	$314	$679	$134	$684
Scenario 8	*EARLY BASELOAD*	$288	$286	($1,781)	$124	$35	$340	($104)	$428
Scenario 9	*EARLY COAL; EXTEND MONTI*	$163	($93)	($1,221)	$260	($121)	($367)	($144)	($272)
Scenario 10	*EARLY KING; EXTEND MONTI*	$104	($16)	($416)	$195	$77	($167)	$39	($143)
Scenario 11	*EARLY COAL; EXTEND PI*	($150)	($392)	($1,780)	($78)	($274)	($714)	($404)	($544)
Scenario 12	*EARLY COAL; EXTEND All NUCLEAR*	($165)	($453)	($1,511)	($34)	($121)	($762)	($362)	($688)
Scenario 13	*EXTEND MONTI*	$10	($7)	$166	$36	$384	$327	$98	($40)
Scenario 14	*EXTEND PI*	($314)	($364)	($172)	($264)	($33)	($413)	($266)	($436)
Scenario 15	*EXTEND All NUCLEAR*	($267)	($340)	($53)	($192)	$261	($264)	($114)	($447)

The deltas in the table above were derived by comparing the total NPV costs of each baseload scenario to the Reference Case/Scenario 1.

Table X-11: Strategist Net Present Value Results for North Dakota Scenario and Preferred Plan Sensitivities

Child Run	Description	Base - PVSC	A-PVRR	I-Low Externality	J-Low Externality, Low Regulatory	K-Mid Externality, Mid Regulatory	L-High Externality	M-No Reg or Externality Costs
Scenario 1	Supplement North Dakota Scenario		$37,061					
Scenario 9	Supplement North Dakota Scenario		$37,373					
Scenario 9	*EARLY COAL; EXTEND MONTI*	$42,818	$37,896	$40,481	$38,687	$40,923	$49,813	$37,706
Scenario 9	Wind Available 2023 @ $500/kW	$42,818	$37,896					
Scenario 9	Solar @ 50% ELCC Throughout	$42,806	$37,806					
Scenario 9	Sherco CC Alternatives - 7HA01 1x1	$42,869	$37,830	$40,299	$38,665	$40,925	$49,219	$37,638
Scenario 9	Sherco CC Alternatives - 7HA02 1x1	$42,772	$37,719	$40,246	$38,558	$40,826	$49,342	$37,537
Scenario 9	Sherco CC Alternatives - 7HA02 2x1	$42,922	$37,917	$40,534	$38,716	$40,994	$50,034	$37,713
Scenario 9	DSM/DR - Add DR Bundle 2	$42,840	$37,862	$40,424	$38,667	$40,921	$49,698	$37,665
Scenario 9	DSM/DR - Add EE Bundle 3	$43,559	$38,678	$41,230	$39,451	$41,676	$50,490	$38,476

The numbers in the table above represent 2020-2045 total NPV costs.

Table X-12: Strategist Net Present Value Deltas for North Dakota Scenario and Preferred Plan Sensitivities

Child Run	Description	Base - PVSC	A-PVRR	I-Low Externality	J-Low Externality, Low Regulatory	K-Mid Externality, Mid Regulatory	L-High Externality	M-No Reg or Externality Costs
Scenario 1	Supplement North Dakota Scenario		$0					
Scenario 9	Supplement North Dakota Scenario		$313					
Scenario 9	*EARLY COAL; EXTEND MONTI*	$0	$0	$0	$0	$0	$0	$0
Scenario 9	Wind Available 2023 @ $500/kW	$0	$0					
Scenario 9	Solar @ 50% ELCC Throughout	($11)	($90)					
Scenario 9	Sherco CC Alternatives - 7HA01 1x1	$51	($66)	($183)	($22)	$2	($594)	($68)
Scenario 9	Sherco CC Alternatives - 7HA02 1x1	($45)	($177)	($235)	($129)	($97)	($471)	($170)
Scenario 9	Sherco CC Alternatives - 7HA02 2x1	$105	$21	$53	$29	$71	$220	$6
Scenario 9	DSM/DR - Add DR Bundle 2	$22	($34)	($57)	($20)	($2)	($116)	($41)
Scenario 9	DSM/DR - Add EE Bundle 3	$742	$782	$749	$764	$753	$676	$770

The Supplement North Dakota Scenario deltas above were derived by comparing the total NPV costs of each scenario to Scenario 1 Supplement North Dakota Scenario. All other deltas were derived by comparing the total NPV costs of each Scenario 9 sensitivity to Scenario 9 – Early Coal; Extend Monti.

XI. SUPPLEMENT PREFERRED PLAN SENSITIVITIES – RELIABILITY ANALYSES

Traditional capacity expansion modeling that informs long-term resource planning optimizes selection of generating resource types based on their ability to meet projected system capacity needs in each planning year. As discussed in detail in Attachment A, Section VI: Resource Attributes, it is becoming increasingly important to also ensure that future resource portfolios provide the right mix of energy, capacity, and flexibility attributes when they are needed to ensure reliable service to customers.

This Supplement marks our first use of the EnCompass modeling tool, which allows for some level of energy and capacity adequacy testing subsequent to capacity expansion modeling. While we expect we will continue to learn and gain experience with EnCompass over time, we used its 8,760-hour modeling capabilities to perform some energy and capacity adequacy analysis. Time did not allow for comprehensive testing of all scenarios, sensitivities, and assumptions, so we focused our efforts on our Supplement Preferred Plan and a few sensitivity plans that are representative of futures with high proportions of variable resources. While our analysis was limited in scope, we believe the testing we performed provides valuable insights on energy and capacity adequacy in a highly renewable future by identifying plans – such as Scenario 9 – 50 percent ELCC – that are more likely to have energy adequacy issues. Additionally, we believe the testing we performed provides more evidence that our Supplement Preferred Plan will perform adequately under a variety of grid conditions.

A. Modeling Approach

Recognizing that we are moving to a future with less baseload, intermediate and peaking generation and more variable renewables, we selected four specific generation portfolios from the multitude of scenario and sensitivity options for detailed hourly testing. These four portfolios included our Supplement Preferred Plan – selected to confirm our Supplement Preferred Plan is reliable – and three Supplement Preferred Plan sensitivity portfolios. We selected the sensitivity portfolios – two Futures Scenarios and a sensitivity that tests holding solar capacity accreditation constant at 50 percent through the planning period – specifically because they included the lowest levels of firm dispatchable generation and thus highest levels of variable resources. See Table XI-1 below for a brief description of each of the capacity expansion plans included in our adequacy testing.

Table XI-1: Summary of Capacity Expansion Plans Selected for Energy and Capacity Adequacy Analysis

Capacity Expansion Plan	Description and Rationale for Testing
Scenario 9 - Supplement Preferred Plan	To ensure energy adequacy of the Supplement Preferred Plan under historical resource and load shape assumptions.
Scenario 9 – P (High Distributed Solar Future)	Scenario contains low technology cost assumptions, so the 2034 portfolio contains a relatively higher share of batteries and substantially less firm peaking generation than Scenario 9 under default assumptions.
Scenario 9 – Q (High Electrification Future)	Scenario contains low technology cost assumptions and high load, so the 2034 portfolio contains more capacity overall; primarily a high proportion of batteries and variable renewables and less firm peaking capacity than Scenario 9 using default assumptions.
Scenario 9 – 50 percent ELCC	Scenario assumes fixed 50 percent capacity credit for solar in all years, which significantly increases incremental solar additions and reduces firm peaking capacity selected but results in approximately the same amount of storage as Scenario 9 under default assumptions.

We summarize the adequacy testing process we used in Figure XI-1 below.

Figure XI-1: Energy and Capacity Adequacy Testing Process

Capacity Expansion Plan models → Identify optimal combinations of generation assets (Capacity Expansion Plans or CEP) given predetermined sets of constraints and assumptions

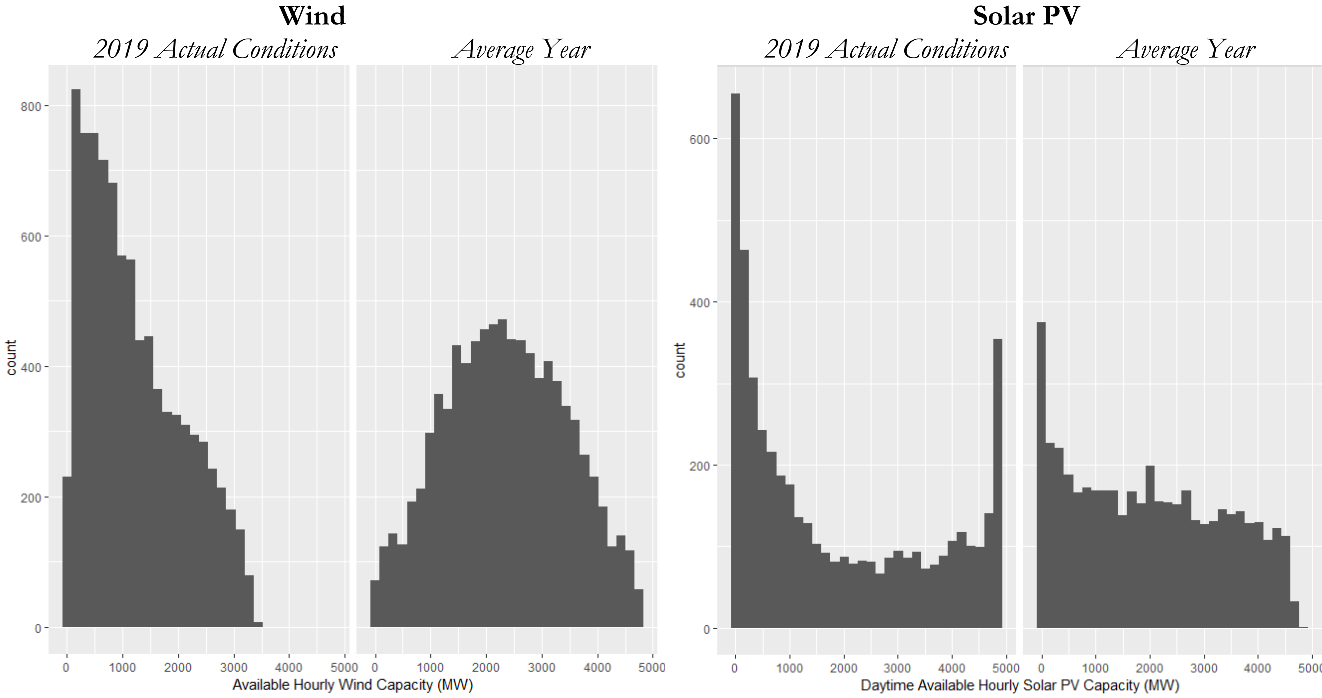
For each Capacity Expansion Plan → Dispatch the plan's selected generation assets in production cost models that assume a variety of historical conditions

For each Production Cost Model → Identify all periods where the Company lacks adequate resources to meet system needs

We tested the generation portfolios that resulted from the capacity expansion modeling for the four scenarios discussed above against a variety of actual historical conditions – using the EnCompass production cost model to identify whether there were periods of high reliability risk; in other words where customers' needs may outstrip the resources we have available to serve them under that specific future scenario. We used actual historical hourly load and renewable shapes from 2019 to simulate how each generation portfolio would have performed given actual weather history. Using this dataset allowed us to assess generation portfolios performance under recent actual historical grid conditions as opposed to the "average" year hourly load and renewable shapes used in the majority of our Supplement Resource Plan modeling.

We chose to use 2019 historical shapes because actual conditions can often be very different – and more challenging – than the averages otherwise used in our traditional capacity expansion and production cost modeling. To illustrate how different actual conditions can be from the averages, Figure XI-2 below shows actual hourly wind and solar PV generation profiles from the 2019 Actual Conditions compared to average wind and solar PV profiles used in capacity expansion modeling.

Figure XI-2: Histogram of Frequency of Hourly Production Levels – 2019 Actuals as Compared to Average Year Used for Capacity Expansion Modeling[80]



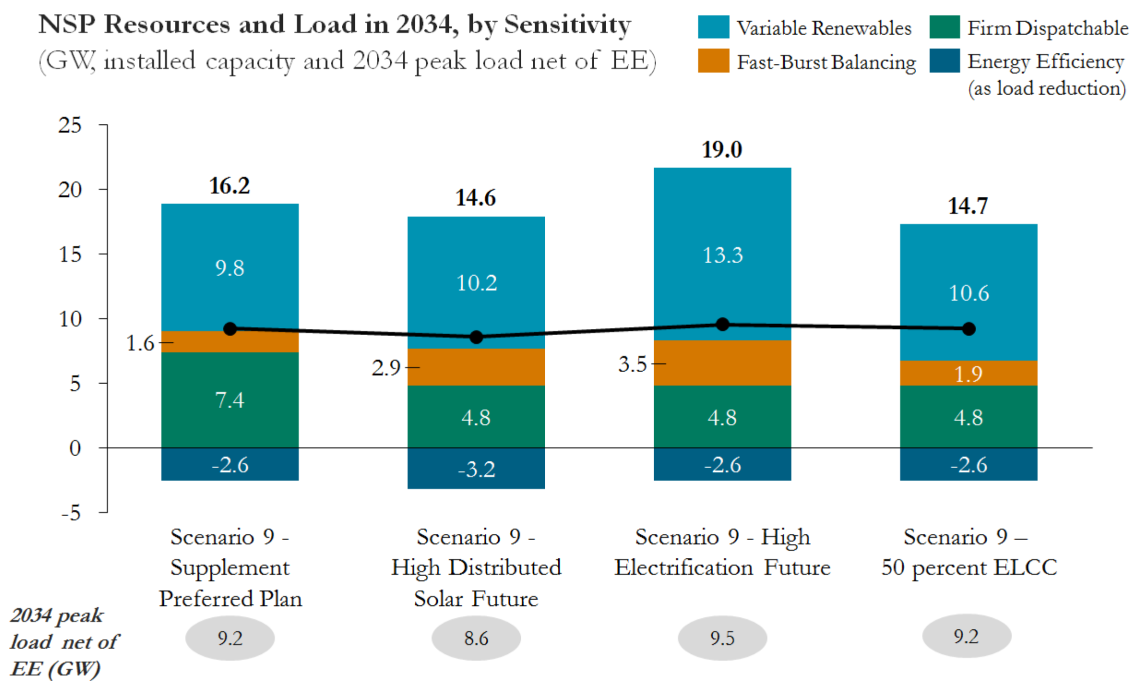
The findings of this analysis provided us with valuable insights about how reliably the four selected generation portfolios could meet system energy and capacity needs in 2034, if the plans faced the same pattern of hourly load and generation profiles seen in 2019.[81] We selected the year 2034 for the analysis because it is the final year of the planning period and thus is the year in which each portfolio had the least amount of firm dispatchable traditional capacity remaining. We did this by adjusting the 2019 Actual Conditions hourly renewable and load shapes to match the generation production and load levels of the renewables and load projected for each of the four portfolios in 2034.

We portray the full resource capacity mix for each of these generation portfolios in planning year 2034 in Figure XI-3 below. We have categorized the capacity into firm dispatchable,[82] fast burst balancing (which includes DR and battery storage), variable

[80] Figure XI-2 illustrates this comparison for the Scenario 9 – Supplement Preferred Plan.
[81] The actual 2019 hourly demand pattern was scaled to meet the 2034 projected peak load level for each scenario and the 2019 hourly generation profiles were applied to the wind and solar capacity in each plan tested. The shapes of the hourly demand and generation patterns are therefore preserved but appropriately scaled to reflect the anticipated level of demand and generation in 2034.
[82] For 2034, firm dispatchable includes nuclear, natural gas/oil, biomass, and hydroelectric resources.

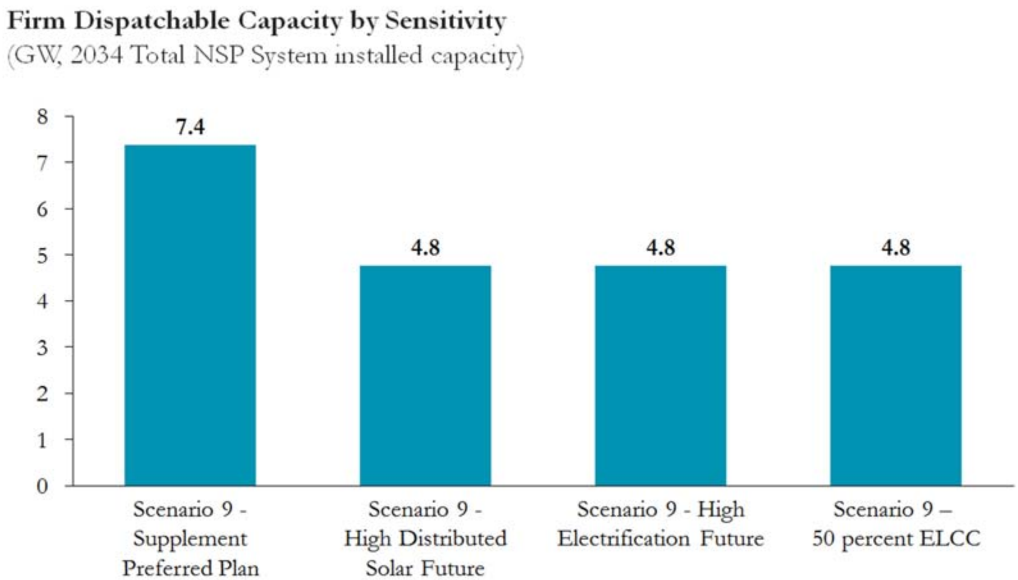
(which includes wind and solar) and EE. The chart clearly illustrates that the sensitivity portfolios are much more reliant on variable resources – having 35 percent less firm dispatchable capacity than the Supplement Preferred Plan.

Figure XI-3: Installed Capacity (ICAP) for each Tested Generation Portfolio (Total NSP System, 2034)



A distinguishing feature of the tested portfolios is the proportion of firm, dispatchable resources in relation to the Supplement Preferred Plan portfolio. Figure XI-4 below isolates and highlights the amount each portfolio contains in 2034.

Figure XI-4: Firm Dispatchable Capacity by Portfolio, Total 2034 NSP System Installed Capacity (ICAP)



The Supplement Preferred Plan includes more firm dispatchable capacity, with 7.4 gigawatts (GW), than the other three sensitivity scenarios which each only include 4.8 GW. As we discuss below, this is a primary contributor to the Supplement Preferred Plan's better reliability performance overall.

B. Adequacy Metrics Evaluated

Within the resource planning framework there are several ways to gauge the energy and capacity adequacy of a generation portfolio to help identify risks. This section describes metrics we used with this Supplement. We first illustrate the primary categories of adequacy metrics, then summarize the results for each capacity expansion model we tested. We also provide further technical descriptions as an addendum to this Attachment.

1. *Native Capacity Shortfall*

As discussed in Attachment A Section VI:Resource Attributes, we believe there is substantial risk to our ability to provide reliable service to our customers in some periods, were we forced to rely exclusively on MISO imports to meet a portion of our customers' needs. Most concerning are periods in which we do not own or have under contract, enough generation capacity to meet our full customer need. While we

– as members of MISO – should be able to rely on market purchases to an extent, these purchases are not firm resources, and thus there is no guarantee there will be sufficient market generation or import capacity available to lean on the market in all circumstances. Thus, we are interested in minimizing the number of hours in which we are unable to serve our own customer load due to insufficient native capacity, and the magnitude of those shortfalls.

Figure XI-5 below is an example of a shortfall in native capacity, or inability to fully serve our customers' needs with owned or contracted resources. These results were derived from the Scenario 9 – 50 percent ELCC generation portfolio and represent conditions faced on July 14-15 period in the 8,760-energy and capacity adequacy analysis.

Figure XI-5: Illustration of Native Capacity Shortfall – July 14-15, 2034 (Scenario 9 – 50 percent Solar ELCC)

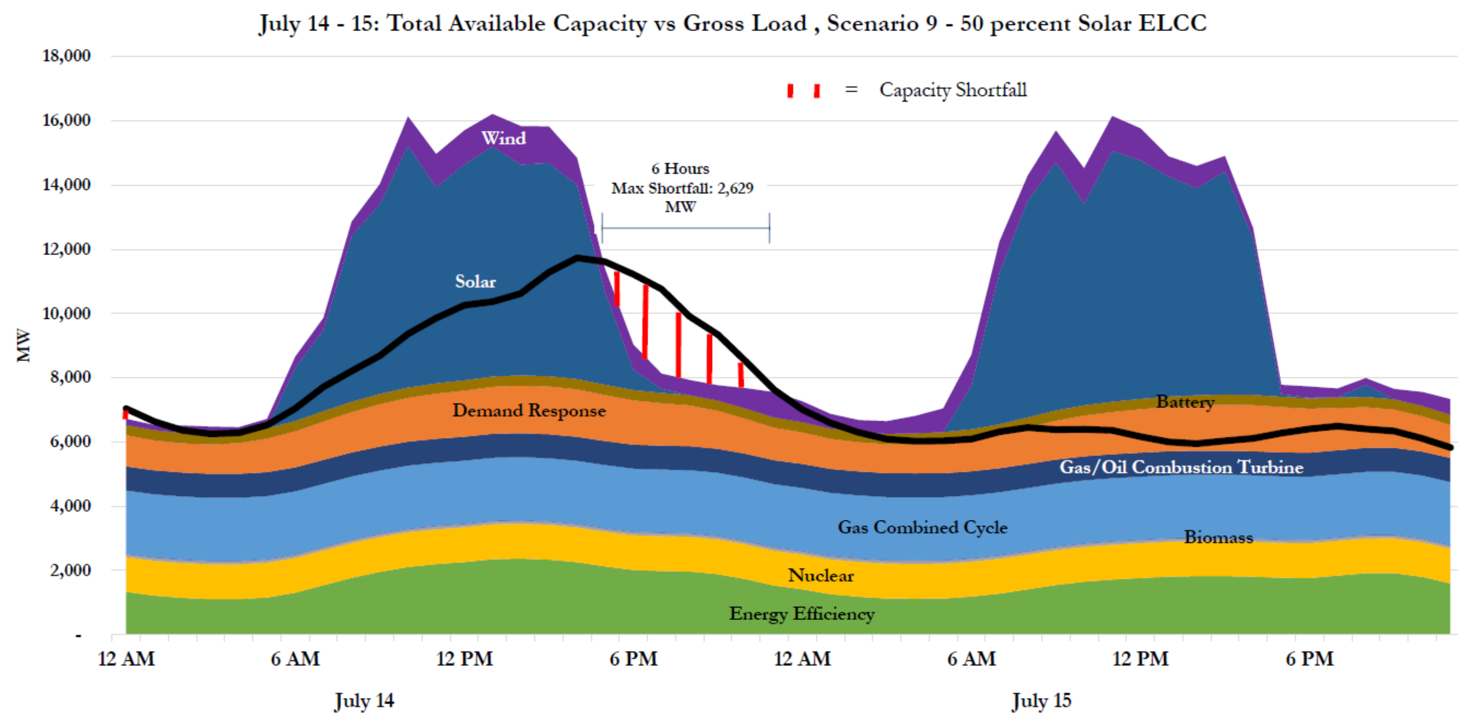


Figure XI-5 shows each type of available generation capacity for the specified scenario in each hour for the time period. The overlay of the Company's gross load – represented by the black line – shows any hours where we do not have sufficient native generating capability available. In this case, given this set of load and renewable generation patterns, we would not have sufficient native capacity available to meet customer needs, and therefore would need to rely on potential resource availability options in MISO in the evening hours of July 14.

2. *Flexible Resource Adequacy*

As discussed in Attachment A Section VI, flexibility is the capability of a resource to be ramped up or down relatively quickly in response to changes in customer demand. While MISO has not established Resource Adequacy measures for this capability, we sought out established metrics for inclusion in our adequacy testing. As part of its analysis on flexible resource adequacy, the California Independent System Operator (CAISO) identifies the maximum three-hour net load ramp – or the change in load minus generation from variable renewable resources– for each month.[83]

Using this metric, constraints occur at different times than many of the native capacity shortfalls discussed above – often during the spring and fall seasons, when load levels are lower and generation from renewable resources comprises a high amount of total generation. In these cases, rapid changes in the volume of renewable generation output can cause proportionally larger fluctuations in net system load. This results in grid challenges from an energy and capacity adequacy perspective in that: (1) it can compress the window of time in which significant changes in net load occur; and (2) it can magnify the size of net load ramp beyond the amount of firm dispatchable and fast-burst balancing resource capacity, causing additional native capacity shortfalls.

This effect is even more prominent in capacity expansion portfolios that have a high percentage of solar capacity. Figure XI-6 below shows an example of a rapid change in net load[84] (the solid red line) in a generation portfolio with high proportion of solar generation. Here, the generation output pattern for these days produce a rapid change in the amount of power generation from solar resources. Since solar comprises a large proportion of this capacity expansion plan, from 3:00 p.m. to 6:00 p.m. the net load changes very quickly; a 7,239 MW swing, in total. As seen in Figure XI-6, the Company would not – in this scenario –have enough firm dispatchable and fast-burst balancing capacity available in its portfolio to fully meet this rapid and large change in net load.

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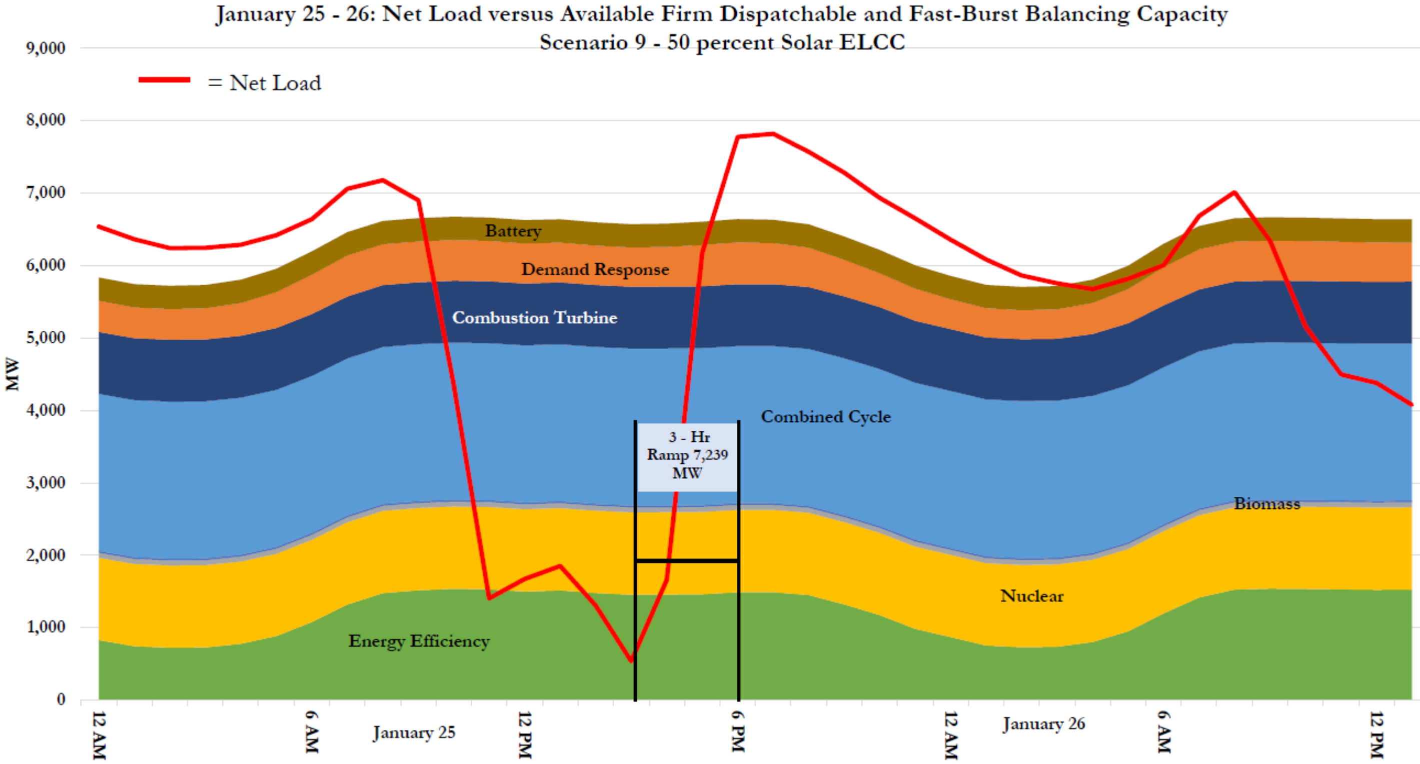
[83] Flexible Capacity Needs and Availability Assessment Hours Technical Study for 2020. California ISO, April 4, 2019.
[84] For a given hour, net load is demand minus the amount of generation from variable resources (wind and solar PV).

Figure XI-6: Illustration of High Three-Hour Net Load Ramp – January 25-26, 2034 (Scenario 9 – 50 percent ELCC)



In comparison, capacity expansion plans with higher proportions of firm dispatchable capacity do not experience this magnitude of net load ramp during the same time period. For example, the maximum three-hour net load ramp is 4,822 MW in the Supplement Preferred Plan when tested using the same conditions for the same time period. Not only is the ramp smaller in magnitude with the Supplement Preferred Plan, the amount of available resources capable of providing flexibility and balancing attributes to the grid are sufficient to meet the full ramp amount.

In general, this piece of our analysis finds that capacity expansion plans with low amounts of flexibility-supporting resources on days in which weather conditions produce rapid changes in the amount of solar and wind generation output create risk for our system. In those cases, our analysis shows that we would need to rely on external resources from MISO on these days, which introduces availability risk; especially if other load serving entities in our region similarly lean on the market during these hours as discussed further below. To be clear, as a member of MISO, we should rely on market purchases when other MISO resources can serve our load cheaper than our own. However, when we must rely on MISO resources because we do not have adequate capacity to serve our load on an hourly basis, we are exposed to uncapped market risk because we do not have a resource hedge to mitigate our exposure.

3. Maximum Import Assessment

Most of the metrics in this analysis focus on potential outages and unserved energy needs. However, we have also quantified the number of hours each Scenario assumes that the Company relies on a high level of MISO imports – at least 95 percent of the current 2,300 MW-h maximum (2,185 MW-h) of imports or greater. This analysis highlights periods in which we are heavily reliant on external resources from MISO. As indicated in Attachment A Section VI, the maximum amount of external capacity we can rely on may, in reality, vary during different seasons – as our share of total network load varies by season – and with different sets of regional grid conditions. Minimizing the number of hours where we would require the maximum MISO import capability, therefore, reduces our risk of being unable to provide reliable service to our customers.

4. Industry Metrics

MISO, NERC, and others in the electric industry have additional methods of characterizing capacity and energy shortfalls, including Loss of Load Hours (LOLH), Loss of Load Equivalent (LOLE), and Expected Unserved Energy (EUE). EnCompass automatically calculates these metrics, and we include the results of these for each scenario tested in Table XI-2 below. The main difference between these and the Native Capacity Shortfall and Flexible Resource Adequacy metrics discussed above is that these *automatically* incorporate the current maximum power import capability from MISO (2,300 MW per hour) into the calculation to determine whether enough resources exist to serve customer load, rather than allowing us to examine the extent of the potential deficit. Due to the limited amount of time we had to develop our models with EnCompass, we modeled a fixed level of MISO import capability in the analysis. That said, we believe automatic inclusion of a fixed level of MISO import capability may undermine the relevance of EnCompass model results for these industry metrics, because MISO import capabilities vary over time, and there is no guarantee the maximum import capability will be available to the Company when it is needed. As we conduct additional adequacy testing in the future, we will investigate assumptions about import capability and its impact on energy and capacity adequacy in more detail.

5. *Summary of Findings*

Table XI-2 summarizes the results of this analysis from the stress conditions we applied to the capacity expansion Scenarios tested.

Table XI-2: Energy and Capacity Adequacy Metrics for Tested Expansion Plan Scenarios

	Native Capacity Shortfall Metrics					Flexible Resource Adequacy Metric	Maximum Import Metric	Industry Metrics		
Expansion Plan (Test Dataset in Parentheses)	**# of Native Capacity Shortfall Events**	**Average Duration of Shortfall Events (hours)**	**Average Intensity of Capacity Shortfall (MW)**	**Longest Shortfall Event (hours)**	**Peak Capacity Shortfall During 2034 (MW)**	**Maximum 3 – Hour Upward Ramp (MW)**	**# of Hours with High Imports**	**LOLH (Hours)**	**LOLE (Days)**	**EUE (MWH)**
Baseline – Scenario 9 - Supplement Preferred Plan (Default)	0	0	0	0	0	4,760 (February)	9	0	0	0
Scenario 9 - Supplement Preferred Plan (2019)	4	1.75	363	2	615	5,506 (June)	158	0	0	0
Scenario 9 – High Distributed Solar Future (2019)	14	2.57	481	5	1,232	7,221 (June)	157	0	0	0
Scenario 9 – High Electrification Future (2019)	21	2.00	429	6	1,037	7,152 (March)	674	0	0	0
Scenario 9 – 50 percent ELCC (2019)	159	3.97	604	22	2,629	7,239 (January)	311	5 (2 separate events)	2	2,575

Note: *The expansion plan with the greatest shortfall is shown in red font for each metric.*

C. Comparison of Plans for a Stress Week

In addition to comparing the results outlined in Table XI-2 above, we provide, as Figures XI-7 through XI-10, a snapshot of each tested Scenario's capacity expansion plan for a "stress week" over December 5-10, 2034 – again using actual customer load and renewable generation patterns from 2019. Seeing how each capacity expansion portfolio is expected to serve a historically observed load pattern provides additional perspective on the types of energy and capacity adequacy gaps that are likely, and the types of resources that would help mitigate such gaps and shortfalls.

The only generation portfolio tested with no native capacity shortfalls during this stress week is the Supplement Preferred Plan. Two of the other plans: (1) Scenario 9 – High Distributed Solar Future; and (2) 9 – High Electrification Future, have small capacity shortfalls that could be served by external resources from MISO, if available, or additional native fast-burst balancing or flexible sources. One scenario (Scenario 9 – 50 percent ELCC) has a substantial number of shortfalls and requires a large degree of reliance on external MISO resources or substantial additions in native firm capacity.

Figure XI-7: Stress Week Assessment: Scenario 9 - Supplement Preferred Plan

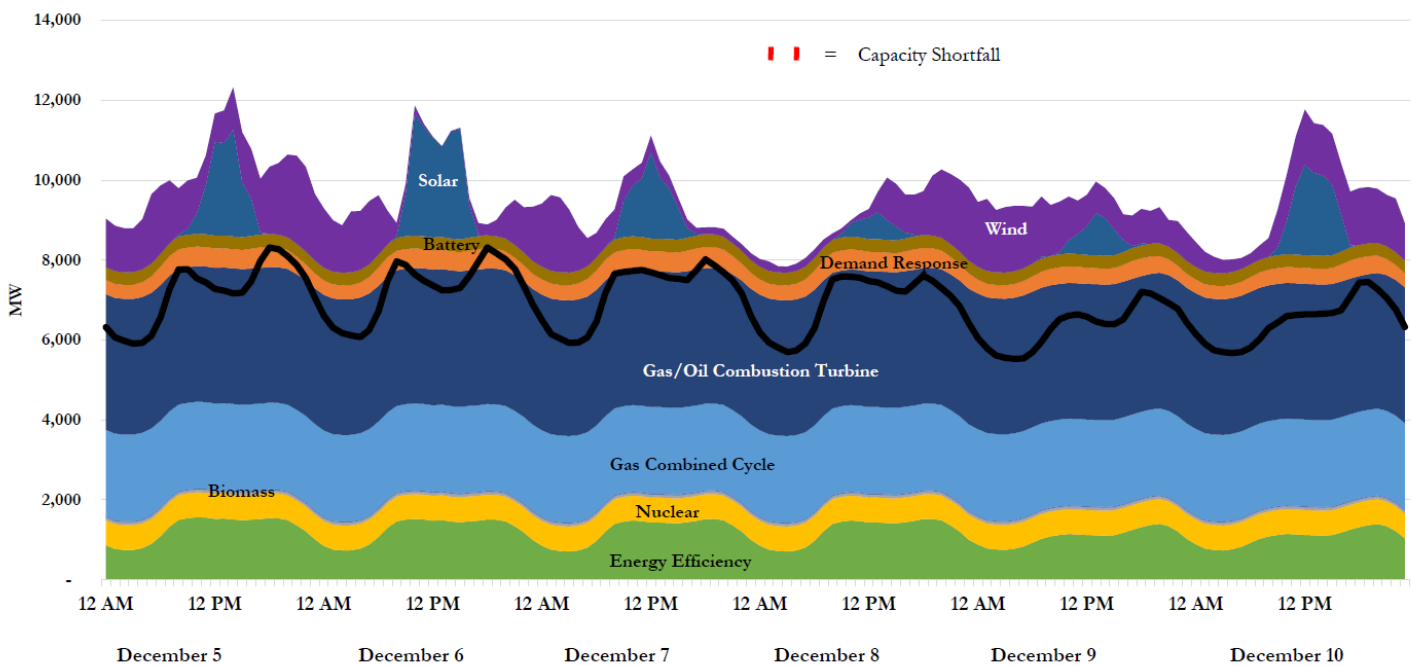


Figure XI-8: Stress Week Assessment: Scenario 9 – High Distributed Solar Future

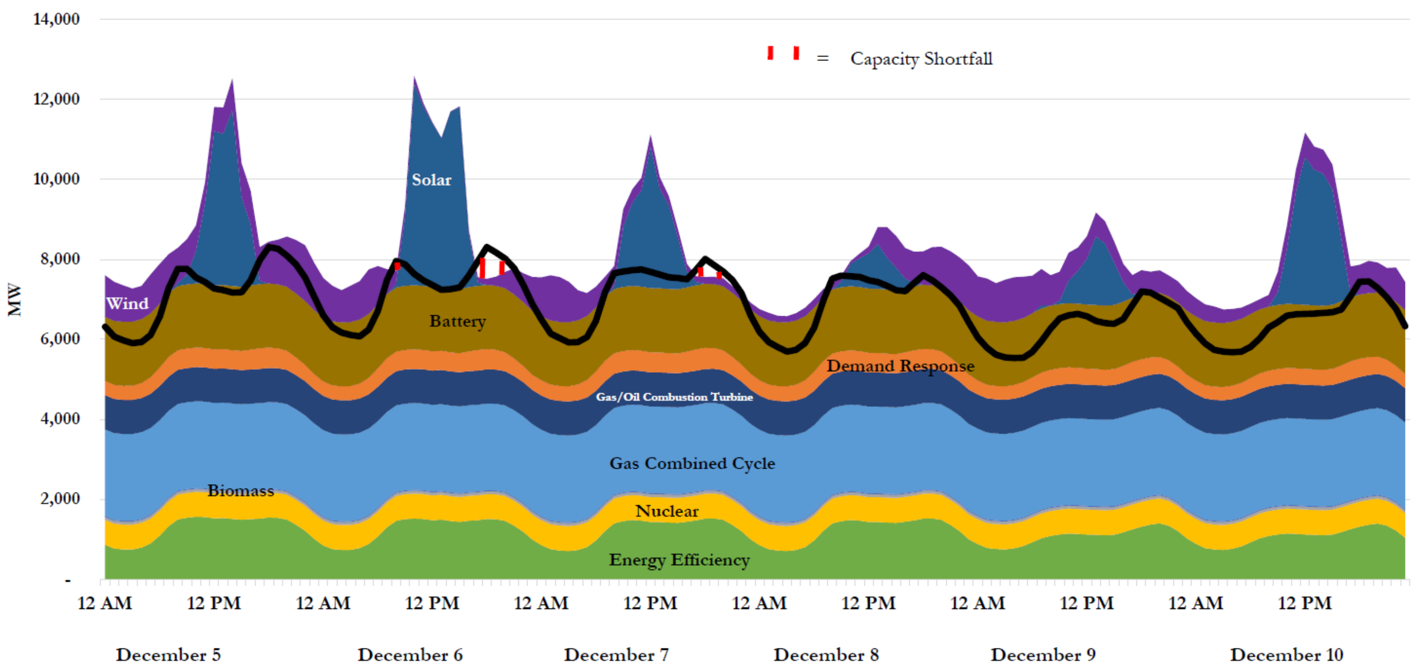


Figure XI-9: Stress Week Assessment: Scenario 9 – High Electrification Future

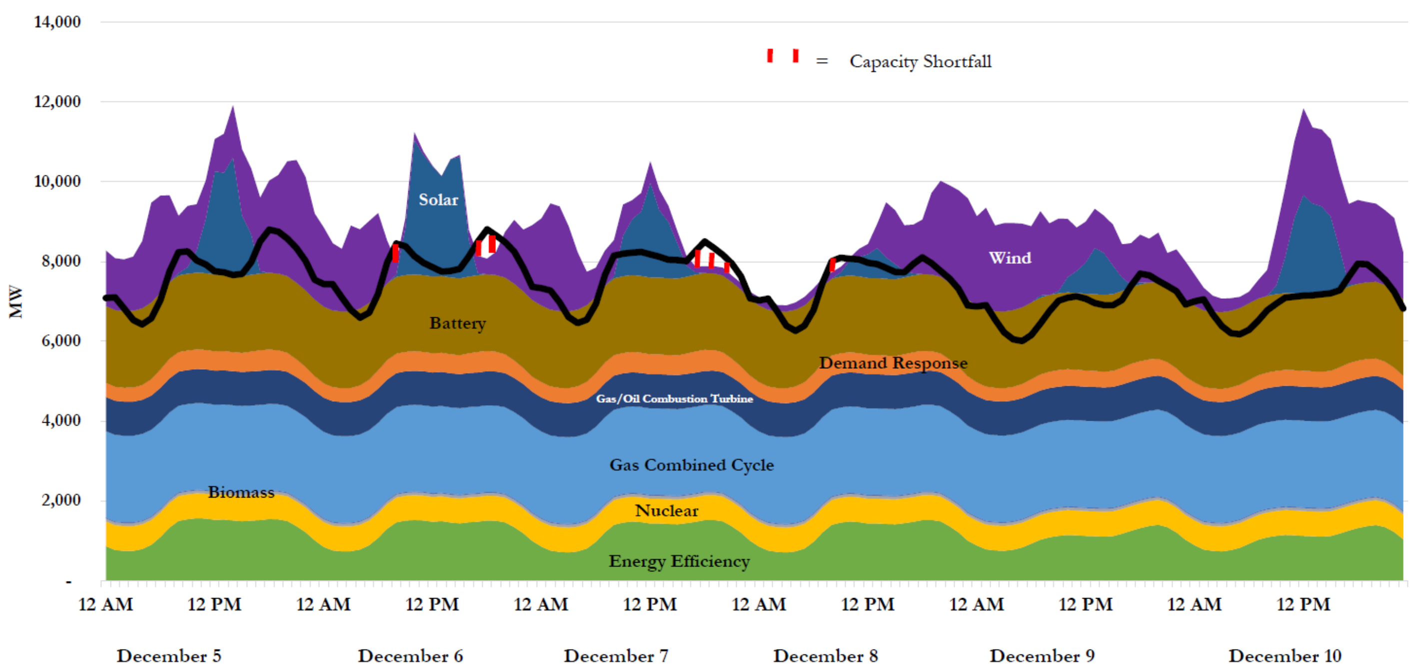
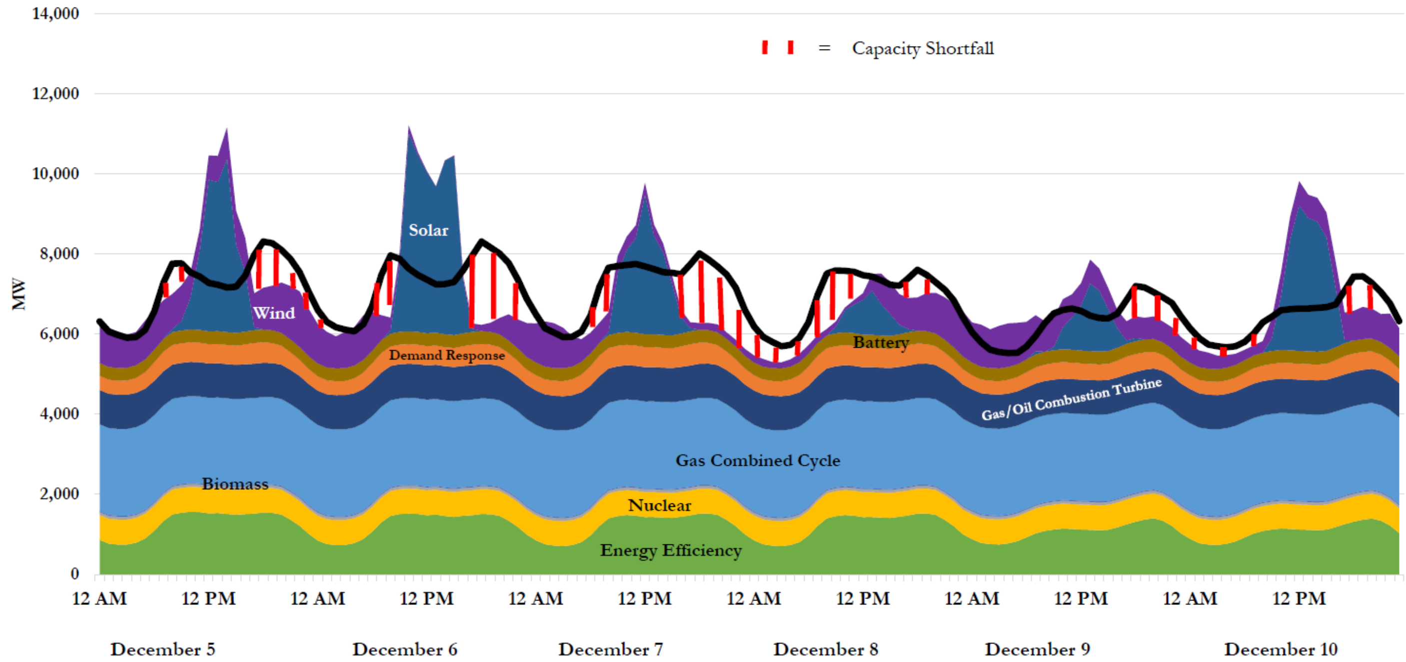


Figure XI-10: Stress Week Assessment: Scenario 9 – 50 percent Solar ELCC



As our system continues to evolve and transition further to include increasingly higher levels of variable resources, robust analyses, which likely include additional years of renewable and load shape history, will be needed to explore which shortfalls can be reliably addressed with fast-burst balancing resources such as demand response and batteries, versus firm dispatchable resources.

D. Limitations

It is important to note that we were only able to test a few capacity expansion plans prior to the filing of this Supplement. Energy and capacity adequacy testing cannot start until we have a set of completed expansion plans and production cost models from the capacity expansion modeling process, and the process of transitioning to the completely new EnCompass software and developing the initial capacity expansion plans and production cost models was time and effort intensive. Further, adequacy testing is a time-intensive analysis process that involves examining hourly-level production cost modeling data across the several key dimensions discussed above. Consequently, while we believe the energy and capacity adequacy testing we performed provides valuable insights, time did not allow for more comprehensive testing of additional scenarios and sensitivities, or incorporating additional years of historical data by which to simulate portfolios' performance against load and renewable shapes.

E. Summary and Conclusion

While we continue to develop a full understanding of all of the EnCompass model's energy and capacity adequacy analyses capabilities, the above findings indicate risks associated with portfolios that rely more heavily on variable renewables and use-limited resources. As demonstrated in Table XI-2 above, the Supplement Preferred Plan exhibits few to no issues under the typical conditions that were used as a default assumption for baseload scenario modeling. When evaluated under the 2019 actual historical conditions, we encountered more periods in which native capacity is not sufficient to serve our customers – and our import capabilities were at maximum levels; but these events were still relatively uncommon.

The three sensitivity portfolios produce more adequacy challenges when evaluated under the 2019 actual shapes, either with the magnitude or length of native capacity shortfalls, 3-hour ramping needs, or others. In particular, the "Scenario 9 – 50 Percent ELCC" portfolio experiences the highest number and duration of native load shortfalls, and a high 3-hour ramp. We believe this evaluation helps to confirm that our use of a declining ELCC metric for solar is appropriate. We also note that the longest shortfall duration in this test scenario far exceeds the capability of a four-hour battery to mitigate and indicates further examination regarding a 100 percent ELCC assumption for battery energy storage is warranted.

In conclusion, we believe these results reinforce the importance of assessing our system's adequacy from an hourly energy and capacity perspective as we retire coal units and add renewables. We will continue to develop our approach to energy and capacity adequacy analyses using EnCompass in the future. That said, when evaluating our full body of modeling results, including these results, we believe they support the conclusion that Scenario 9 is an appropriate choice to form the basis of our Supplement Preferred Plan.

Reference: Definitions of Key Terms and Metrics

Native Capacity Shortfall = The amount of NSP System load that is above and beyond the available capacity from owned and contracted resources for a given hour:

Load > Available Capacity

Average Duration of Shortfall Events = Average number of hours per Native Capacity Shortfall Event

Average Intensity of Capacity Shortfall = The peak amount of capacity needed during each event, on average, to avoid a native capacity shortfall.

EUE = Expected Unserved Energy (MWh) is total amount of energy that could not be served.

Longest Shortfall Event = The length, in hours, of the longest event where a native capacity shortfall occurred.

LOLE = Loss of Load Expectation is the number of days that experienced a loss-of-load event (LOLH > 0).

LOLH = Loss of Load Hours is the number of hours in which load exceeds available generation and import capability.

Maximum 3-Hour Upward Ramp = The maximum upward change in net load over a continuous three-hour period.

Net Load = Load minus generation from variable renewable resources (wind and solar PV)

# of Hours with High Imports = The numbers of hours in each scenario where the amount of market purchases required to serve customer load was at or over 95 percent of the system maximum import limit of 2,300 MW-h.

Peak Capacity Shortfall during 2034 = The maximum native capacity shortfall, in MW, per each scenario tested.

XII. CUSTOMER RATE & BILL IMPACTS

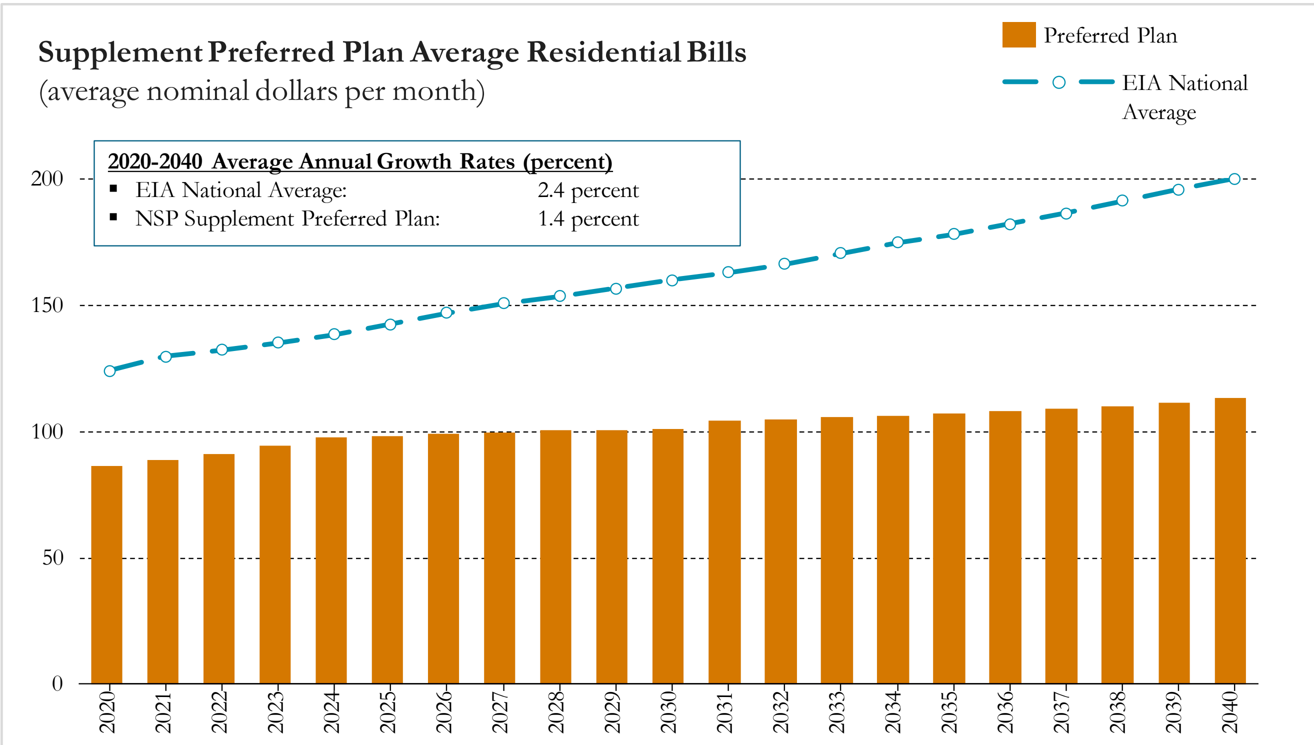
Minn. R. 7843.0500, subp. 3, requires the Commission to evaluate resource plans on, among other things, their ability to "keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints." Our July 2019 initial filing included a customer cost analysis that showed our Preferred Plan achieved our carbon goals and reliability objectives while maintaining affordability. While our methodology and approach to calculating customer cost impacts has remained largely the same in this Supplement, there are several fundamental changes to modeling inputs and approaches that lead us to an updated view of our Supplement Preferred Plan's customer cost impacts. Specifically, we are now using EnCompass model outputs, rather than the legacy Strategist model's outputs, for our analyses and we have refreshed many of our modeling inputs and assumptions to incorporate the latest available data. These changes, and the resulting differences in capacity additions and system dispatch, result in changes in our overall assumed revenue requirements and sales.

Our refreshed customer cost impact analysis finds that our Supplement Preferred Plan continues to keep average residential customer bills well below the national average. Additionally, our projected average bill and rate growth remains below inflation and is nearly a full percentage point below national averages for bill and rate growth. That said, we do note that the Supplement Preferred Plan projects slightly higher rates, when compared to our initial filing and national average rate estimates, and we discuss key drivers of these differences below. When reviewed as a whole, however, we believe these metrics show that our Supplement Preferred Plan maintains affordability while achieving substantial carbon reduction benefits relative to our Supplement Reference Case, and that it keeps customer bills and our rates as low as practicable.

A. Residential Bill Analysis

Energy efficiency (EE) is a cost-effective part of our future plans on a system-wide basis; and it contributes to keeping average customer bills low. However, as discussed further below, our plans to increase EE achievements over the next several years is one key driver of upward pressure on our electricity rates. As a result, we believe it is important to begin examining our Supplement Preferred Plan's customer cost impacts by reviewing the effects on an average residential bill. As shown in the Figure below, NSP System residential customers – on average – pay substantially less per month than the national average. In the early years of the forecast, this difference is attributable to lower than average electricity consumption, driven partially by our anticipated EE achievements (because when energy sales are reduced, the same level of fixed costs are spread over fewer kilowatt hours (kWh)). We also expect our average bill levels will grow more slowly than the national average, by approximately a full percentage point per year.

Figure XII-1: Systemwide Supplement Preferred Plan Average Residential Bills



That said, we acknowledge that there can be wide variation in customers' ease of access EE measures that will help flatten effects of rate increases going forward. We note that, in our Relief and Recovery Plan filed with the Commission in response to the COVID-19 pandemic (in Docket No. E,G999/CI-20-492), we are proposing several investments to better reach low-income customers with EE benefits.[85]

B. Rate Impacts and Key Drivers

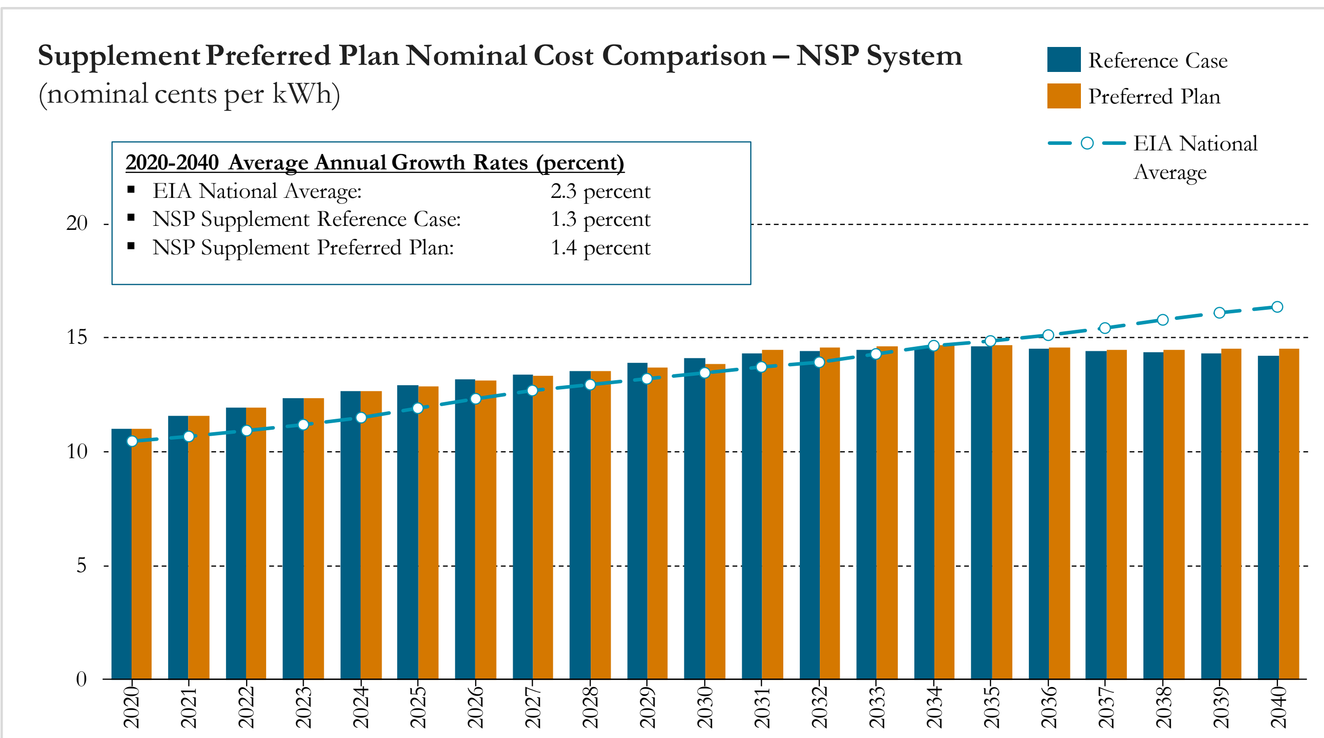
In addition to reviewing average residential bill impacts, we believe it is important to consider the impacts of the Supplement Preferred Plan on our rates. In this Section, we discuss the Supplement Preferred Plan's forecasted cost impacts relative to the updated Reference Case, as well as changes relative to our initial July 2019 filing. Overall, our Supplement Preferred Plan results in slightly higher rates as compared to

[85] *See* Docket No. E,G999/CI-20-492. COVID-19 RELIEF AND RECOVERY REPORT (June 17, 2020) at 17-18.

the updated Reference Case, although they are similar in most years of the analysis. This finding is consistent with the relatively low, but positive, delta between the PVRR for Scenario 9 as compared to the Reference Case presented in Section II: Modeling Framework and Results[86].

We project that the Supplement Preferred Plan would result in rate increases of approximately 1.4 percent per year through 2040 as compared to the updated Reference Case growth rate of 1.3 percent, on a system-wide basis. We note that this estimated rate increase, on an average annual basis, is nearly one percentage point lower than the national average rate increase, as projected by the Energy Information Administration (EIA),[87] and lower than the rate of inflation. In other words, we can achieve the Supplement Preferred Plan's significant carbon emissions reductions with cost impacts that are significantly less than expected national average increase in electricity prices. This rate of increase is also less than the rate of inflation.

Figure XII-2: Systemwide Supplement Preferred Plan Nominal Cost Comparison



[86] We note that once externality and regulatory costs of carbon are factored in, the Supplement Preferred Plan results in present value societal benefits relative to the updated Reference Case, but these are not factored into rate or bill analysis.
[87] See Energy Information Administration. *Annual Energy Outlook 2020*. (January 2020). Available at: https://www.eia.gov/outlooks/aeo/index.php

Relative to our July 2019 filing, our estimated average rates are slightly higher in this Supplement, and they remain above the updated national average further into the forecast period. There are three key contributing factors to differences between our initial filing's rate impact analysis and the Supplement findings.

First, our sales estimates – in both the updated Reference Case and Supplement Preferred Plan – decreased relative to the forecasts used in our initial filing. As noted above, the estimated decline in sales is primarily attributed to an increase in levels of EE assumed in our underlying demand forecasts, which is partially offset by higher projected electric vehicle electricity consumption in the latter years of the forecast period. As a result of sales declines attributable to EE, the total revenue requirements for both the Reference and Preferred Plans are spread over fewer kWh sales, and the rates needed to recover the required revenue increase.

Second, we note that our total revenue requirements have increased relative to our initial filing. Some of the difference is attributable to Strategist and EnCompass being fundamentally different models that handle market dispatch differently. However, we observe that the largest changes in cost factors between the July 2019 filing and this Supplement include increased fixed costs from renewable capacity expansion and increased fuel and variable operating and maintenance (O&M) costs, with increases in market interaction benefits partially offsetting those cost drivers. The Supplement Preferred Plan includes more renewable capacity additions than our initial Preferred Plan, and although cost assumptions for some renewable technologies have declined – as a result of projected technology improvements – the increase in capacity additions results in somewhat higher revenuer requirements overall. Further, variable O&M costs increase overall, partially as a result of the costs of operating more capacity, and partially because the Strategist modeling used as the basis of our revenue requirements analysis in the initial filing did not account for startup and other hourly operational costs that the EnCompass model does capture. These upward pressures are offset somewhat by the Supplement Preferred Plan's market interactions, which result in more savings than in our initial Plan.

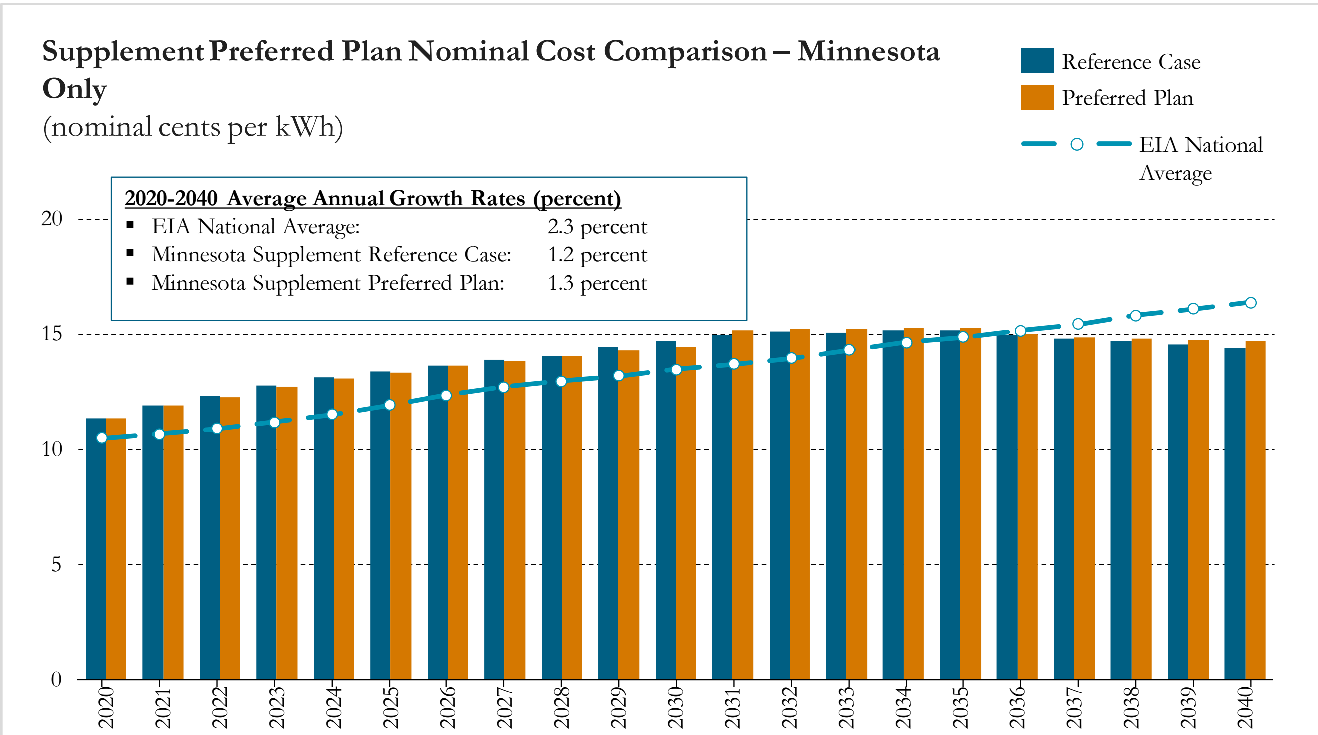
Third, we note that the EIA's 2020 projection of national average nominal electricity rates has declined – both in terms of the rate level and the pace of expected future growth – relative to the 2019 vintage we used in our initial filing. EIA's *2020 Annual Energy Outlook* (AEO) notes that average customer rates declined primarily as a result of declining technology costs and lower natural gas price forecasts relative to the assumptions used in the 2019 AEO.[88] EIA notes that its price forecasts are very sensitive to these factors, and especially natural gas price trends. This change lowers the estimated benchmark of national prices against which we compare our Supplement Preferred Plan.

When considered altogether, these three factors contribute to our findings that the Supplement Preferred Plan increases forecasted rates relative to our initial filing and are expected to be somewhat higher than the national average in the near term. However, it is also important to note that our Supplement Preferred Plan still results in estimated rate growth that remains well below – by nearly a full percentage point – EIA's estimated national average rate of growth of 2.3 percent per year, while it achieves substantial carbon reduction relative to current system levels and the updated Reference Plan.

When we look at the Minnesota customers-only projected rate impact, the factors discussed above remain. This is primarily because nearly all of the estimated EE effects – which place upward pressure on rates – are attributed to Minnesota customer adoption. That said, the average annual growth projected for Minnesota-specific rates is marginally lower than the NSP System overall. This is driven by more growth in the underlying energy sales forecasts relative to the system overall, which spreads Minnesota-specific revenue requirements over a broader base of consumption. Again here, we note that the expected growth rate attributable to the Supplement Preferred Plan is substantially lower than expected national average rate growth.

[88] See Energy Information Administration. *Annual Energy Outlook 2020 - Electricity*. (January 2020), at slide 25. Available at: https://www.eia.gov/outlooks/aeo/pdf/AEO2020%20Electricity.pdf

Figure XII-3: Minnesota Customers Supplement Preferred Plan Nominal Cost Comparison



Based on the totality of these metrics, we believe our Supplement Preferred Plan keeps customer bills and rates as low as practicable while achieving the substantial carbon reduction benefits we anticipate as a result of the plan.

XIII. UPDATED DEMAND RESPONSE FIVE-YEAR ACTION PLAN

Our Supplement Preferred Plan includes 1,349 MW of demand response resources by 2023. This amount of demand response resources includes a net incremental load increase of 469 MW (453 Gen. MW) compared to our 2017 baseline of 880 MW, meeting the requirements of the Commission's Order to obtain an additional 400 MWs by 2023.[89]

There are a few changes between our initial filing and this Supplement worth noting. Most notably, our Supplement Preferred Plan has increased the amount of demand response added through 2023 from 391 Gen. MW in the initial Preferred Plan to 453 Gen. MW. This increase is largely due to an increase in the base forecast of demand response beginning in 2020 due to a higher load forecast for existing interruptible rates.[90]

The following was also changed:

- Our base forecast now includes a category for Residential Demand Response, which includes both our Saver's Switch program as well as the AC Rewards program. This change aligns our base forecast with the demand response we register with MISO but adjusts the original categorization of these programs; and,

- We have increased the forecast for Small Business Thermostats based on the success of our pilot and approval by the Department of Commerce.[91]

Finally, we note that our forecasts for demand response included in the Supplement Preferred Plan were based on data captured prior to the COVID-19 pandemic emerging in Minnesota. How the pandemic will impact our demand management portfolio moving forward is currently unknown. We continue to believe, however, that we have laid out the best path to achieve additions of 400 MW of demand

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[89] As discussed on page 26 of the Brattle Group Study included as Appendix G2 to the July 2019 filing, the Company has interpreted the Commission's Order to require 400 MW of capacity-equivalent DR, which is a greater value than MW of offset generation, because it incorporates the planning reserve requirement. 469 MW measured as a capacity-equivalent value is equivalent to 453 MW measured as a generator-level value ((469/1.089)/0.95) where the reserve margin is 8.9 percent and the coincident factor is estimated at 95 percent for all existing and potential programs. In this Appendix, we refer to MW measured at the generator-level as Gen. MW.
[90] As noted below, this forecast likely will need to be revisited in light of COVID-19.
[91] February 21, 2020. Decision, *In the Matter of Xcel Energy's Program Modification Request Filed December 23, 2019*, Minnesota Department of Commerce, Docket No. E,G002/CIP-16-115.

response by 2023. In Table XIII-1, below, we lay out our plan for making these additions.

Table XIII-1: Demand Response Five-Year Action Plan

						Estimated Cumulative Potential (Gen. MW)			
	Program	**Regulatory Path**	**Program Status**	**2017 (Baseline)**	**2019**	**2020**	**2021**	**2022**	**2023**
Existing Programs	Electric Rate Savings	CIP (admin); Rate Case (discounts)	Existing	503	461	518	519	520	522
	Residential Demand Response (Including Saver's Switch and AC Rewards)	CIP (admin); Rate Case (discounts)	Existing	348	436	460	474	487	498
	AC Rewards (Smart Thermostats) - Incremental Growth above existing projections	CIP	Existing	-	-	14	59	60	61
	Peak Partner Rewards	CIP	Existing	-	-	15	42	45	45
	Small Business Smart Thermostats	CIP	Existing	-	-	3	4	5	9
	Subtotal Existing			**851**	**897**	**1,010**	**1,098**	**1,117**	**1,135**
New Programs	Two-way communication switches - Saver's Switch Technology Update	CIP	2021-2023 Triennial Plan Filing	-	-	-	-	-	19
	Interruptible Tariff(s)	Miscellaneous Filing	Tariff Filing Fall 2020	-	-	-	40	90	115
	Subtotal New			-	-	**-**	**40**	**90**	**134**
Non-Traditional Programs	Grid Enabled Electric Water Heaters	Non-Traditional - TBD	In design, partially allowed as part of Saver's Switch	-	-	-	4	9	13
	Commercial Building Controls (Auto DR)	Non-Traditional - TBD	In design - Currently not cost-effective	-	-	-	10	15	22
	Other	Non-Traditional - TBD	Various programs in design	-	-	-	-	-	-
	Subtotal - Non-Traditional			-	**-**	**-**	**14**	**24**	**35**

Total Existing, New and Non-Traditional Programs	**851**	**897**	**1,010**	**1,152**	**1,230**	**1,304**
Incremental Program Capacity (Gen. MW)	**0**	**46**[92]	**159**	**301**	**379**	**453**
Incremental Program Capacity with Reserve Margin (MW)						**469**

[92] We note that, we saw a drop in controllable load in 2018 of 27 Gen. MW, due to both attrition and a result of a change in our methodology for calculating interruptible demand calculations that was more useful to the Midcontinent Independent System Operator. We have since seen expansion of our programs by a net increase of load of 46 Gen. MW and a total incremental increase of 73 Gen. MW compared to the 2017 baseline.

A. Incremental Growth of Demand Response

Since 2018, we have increased demand response resources by 73 Gen. MW solely through growth in our existing programs. To achieve the 400 MW addition, however, we are doing more than just adding customers to the programs we already have. In 2020, we launched two new demand response programs: Peak Partner Rewards and AC Rewards Small Business. In addition, we continue to expand our AC Rewards Residential program in other parts of our NSP System service area, including in both Wisconsin and South Dakota. We have also begun pilots across our territory determining the interest in newer technologies such as air-source heat pumps, grid-operated electric water heaters, and rates combined with behavioral demand response. Many of these efforts are occurring in our Colorado service territory due to the ability to utilize active smart meter technology and cost-recovery mechanisms already put into place for these types of efforts. These pilots will continue to expand our reach to customers interested in decreasing their load during certain times of the day or during a control event launched by the Company.

1. New Programs

Initially, we have focused our incremental growth on opportunities for customers in the mid-market segment, which has been the most underserved by existing demand response opportunities. In order to meet this segment's needs, we launched two new options for the 2020 summer control season: Peak Partner Rewards (PPR) and AC Rewards for Business.

PPR, launched in March 2020, is a new program which offers bill credits and access to electric load profile data to business customers that agree to reduce their electrical loads when the electric grid experiences peak demand periods. The program's incentive structure emphasizes actual performance during control periods. These incentives are provided through our Conservation Improvement Program (CIP), and savings are identified through electric load profile data. Our account managers are currently engaged with data centers, schools, and several other commercial and industrial customers who have expressed interest in participating in the program.
AC Rewards for Business expands our existing AC Rewards program into the commercial space, through direct installation of smart thermostats. Customers receive a smart thermostat for free through the program, in addition to a $25 bill credit for participating in demand response. AC Rewards started as a pilot program with 400 enrollees in 2019 and officially launched under the Saver's Switch for Business program beginning in May 2020. The speed with which we were able to transition from a pilot to a full launch is a result of early customer engagement.

2. *Programs in Development*

We continue to work towards developing new products and opportunities for customer demand response participation through expansion of existing programs where appropriate, addition of new traditional programs and tariffs, and addition of non-traditional opportunities. Table XIII-2, below, provides further detail regarding those programs currently in development.

Table XIII-2: Demand Response Offerings in Development

Program Type	Product	Est. Date	Status
Interruptible Offerings	Interruptible Rate	2021	Interruptible Rate to be filed in fall 2020
Smart Water Heating	Electric Water Heating Control	2021	Partially launched in 2020; additional phase in 2021
Commercial Building Controls	Commercial Buildings	2021	Requires a decrease in cost of control equipment
Smart Thermostats	Home Energy Management	2023	Piloting in 2020
Saver's Switch Update	2-way communication	2023	Requires AMI installations and new equipment
Behavioral DR	"Hands-off" DR	2023	Piloting in CO, potential pilot to begin in late 2020 in MN *Technology dependent as AMI is necessary*
Electric Vehicles	Smart Charging	TBD	Program denied through CIP – exploring further opportunities
Critical Peak Pricing	Critical Peak Pricing (Opt-in)	TBD	Reviewing CO program to determine MN benefit
Other	Geo-Targeting	TBD	Pilot for Geo-Targeting to be complete in 2020 – additional development efforts to launch as a result.
Other	Reverse DR	TBD	Reverse DR to be piloted in CO as a customer rate.

By expanding the breadth of our program offerings, we hope to provide customers with the opportunity to participate in demand response offerings that meet their unique needs while expanding the ability to utilize demand response to modify load as future load profiles change. We do note, however, that some of these projects may overlap – meaning a customer may need to choose which works best for their homes or businesses, and that choice may come at the expense of participation in another program. For example, the Company may see a drop-in demand response in existing programs as new programs are offered or the load estimates for a smart thermostat may drop significantly for customers on a time-of-use rate. This overlap is important to acknowledge as we analyze incremental load.

a. Miscellaneous Tariff Request Planned for2020

The next program we hope to launch (in 2021) is an interruptible rate program that would allow increased flexibility, economic pricing and buy-through rates. We intend to file this as soon as early fall 2020 once operation details have been finalized. This program will be utilized similarly to the current Electric Rate Savings program, but it will allow for a wider range of response and control options, including buy-through offerings and seasonal control, along with increased data access for participating customers. We will offer this program as a pilot in order to test price-responsiveness and interest. Unlike PPR, this program is intended for customers with specific load availability for differing seasons (rather than months) and the ability to ramp down or shift operations during an economic event.
Our request has been delayed from our original summer 2020 timeline as we finalize cost analyses to meet the criteria outlined by our stakeholders in 2018-2019. In addition, as we finalize these details, we hope to develop one or two additional offerings (based on the options identified above in Table XIII-2) to bring forward at the same time.

b. Non-Traditional Demand Response

We also plan to pilot non-traditional opportunities and new technologies to satisfy the January 2017 Order. These additional opportunities for demand response are tied to increasing implementation of new technologies, such as EVs and advanced metering infrastructure. Smart charging and advanced metering could enable demand response opportunities, through time-of-use rates and peak time rebates. All of our EV programs and tariffs in Minnesota—including the recently-approved expansion of our Residential EV Home Service program—include time-of-use rate structures. Similarly, we are piloting new whole-home time-of-use rates in connection with advanced meters and are considering new rate design approaches that will be enabled with the capabilities of advanced meters when they are rolled out across our entire service territory.

The specific MW demand response achievements of these programs can be difficult to estimate. However, we plan to include these efforts as part of our demand response goals as technology deployment evolves.

c. Recent Challenges

We have taken, and will continue to take, significant steps to achieve 400 MW of additional demand response by 2023, and we continue to believe this is achievable. However, as noted above, the unforeseeable economic impacts of the COVID-19 pandemic may affect implementation of these plans. This crisis has not impacted all customers equally, and the full extent of its impacts remains unknown. Some business customers have lower to no demand as a result of temporary shut downs, while others have increased demand, but are unable to allow load control because they are providing essential and critical production and services. We have taken a number of actions to mitigate financial impacts to our customers, including flexing customer payment requirements, halting credit actions, and instituting a no disconnections policy. While it is too early to determine the full impact of the pandemic, we have experienced and continue to anticipate a temporary loss of demand response participation from both residential and business customers over the next several months impacting our 2020 forecast.

It is important to also note the value provided by the pandemic in our planning and customer implementation of demand response. Our Peak Partner Rewards offering has allowed customers to continue to participate differently (and, in some cases, with higher demand in particular months) during a time when load is shifting, and continued operations is uncertain. In addition,

- Our AC Rewards program and Smart Thermostat Optimization helps customers maintain lower energy bills even when working from home;
- Through virtual visits, we continue to offer thermostats to residential and small business customers (rather than onsite);
- We actively ordered equipment as part of program implementation ahead of time to prepare for the control season; and
- In a recent Petition, we requested that the Commission allow relief from tariff requirements for customers on existing rates, allowing them to remain on our demand response programs under temporary conditions, rather than be removed from the program permanently.

Despite the challenges of COVID-19, we believe we have set out the right path and are continuing to take responsible action towards achieving 400 MW of additional demand response by 2023.

I. INTRODUCTION

Attachment B replaces Appendix N6 of our July 1, 2019 filing in compliance with the Commission's Order Suspending Procedural Schedule and Requiring Additional Filings issued on November 12, 2019 in this docket (November 2019 Order). Attachment B serves as Xcel Energy's (the Company) Renewable Energy Cost Impact Report (Report) to the Minnesota Public Utilities Commission (Commission) in compliance with Minn. Stat. §216B.1691, subd. 2e. The statute is intended to provide a mechanism for determining and communicating to legislators and constituents what utility rates would be if the 2007 Minnesota Next Generation Energy Act (NGEA) had never been implemented. This Report is intended to be in full compliance with the Commission's January 6, 2015 Order Establishing Uniform Reporting System for Estimating Rate Impact of Minn. Stat §216B.1691 in Docket No. E999/CI-11-852 (January 2015 Order), the November 2019 Order, and the language and objective of the statute.

The NGEA helped to create a framework for utilities to implement expanded renewable energy portfolios. The NGEA requires Minnesota electric utilities to obtain increasing amounts of energy from eligible renewable resources according to a specified timeline. The amounts are calculated in terms of a percentage of each utility's total retail sales. During the 2011 legislative session, legislation was passed which requires utilities to report the impacts of the NGEA on customers. In 2013, the Minnesota Legislature directed the Commission to develop a uniform system for utilities to use when estimating how electric rates have been influenced by Minn. Stat. § 216B.1691. The Commission issued two notices, on November 6, 2013 and April 18, 2014, respectively, seeking comments on Commission Staff's proposed general guiding principles and format for a uniform reporting system. The Commission approved the general guiding principles and format to be used by reporting utilities, including Minnesota Power, at a hearing on October 2, 2014, which was reflected in the January 2015 Order. As ordered by the Minnesota Commission, each utility that files a Resource Plan must calculate the cost of complying with Minn. Stat. §216B.1691.

II. REQUIREMENTS

A. Analyze costs from the year following the last reported year, and for the following 15-years.

B. Include all facilities used to comply with the Renewable Energy Standard and the Solar Energy Standard, regardless of when the facilities were constructed.

C. Calculate direct costs to include payments under power purchase agreements and revenue requirements associated with utility-owned renewable energy projects.

D. Provide a narrative discussion about the impact that adding generators powered by renewable sources may have had on the utility's indirect costs, such as the cost for ancillary services and base load cycling.

E. Include transmission improvement costs.

F. Calculate Energy and Capacity savings arising from avoiding costs that the utility would have incurred directly in the absence of the Renewable Energy Standard and Solar Energy Standard.

G. Calculate past and future emission compliance savings arising from avoiding costs that the utility would have incurred indirectly in the absence of the Renewable Energy Standard and Solar Energy Standard.

H. Report estimated annualized and estimated levelized costs.

I. Calculate the rate impacts of complying with the Renewable Energy Standard, and Solar Energy Standard, separately.

J. Calculate the ultimate rate impact of Minn. Stat. § 216B.1691 to reflect the fact that renewable energy comprises only a fraction of a utility's total energy costs, and consequently most of a utility's energy costs are unaffected by the Renewable Energy Standard and Solar Energy Standard.

In its November 2019 Order, the Commission required that the replacement report:

A. Analyze costs from the year following the last year included in a rate impact report, and for the following 15 years,

B. Include data from all generators using eligible energy technologies, even if Xcel did not expressly acquire them to comply with the Renewable Energy Standard or Solar Energy Standard,

C. Include an estimate of avoided emissions costs (the regulatory cost of CO2 was previously included),

D. Clarify Xcel's method for calculating rate impacts, and

E. Revising and/or clarifying its levelized cost of RES generation and SES generation.

III. METHODOLOGY

For the purposes of this study, the Company calculated separate rate impacts for the RES and the SES. RES and SES rate impact calculations are performed for years 2020 to 2034, which are the 15 years of the IRP Planning Period, and the Current Period 2014-2019 reflecting the period between the prior reporting historic period and the IRP planning period. The RES and SES rate impact includes estimates of transmission costs directly attributable to renewable resources. Cost of transmission embedded in PPA payments are included as well as transmission costs for new transmission assets required to access and transmit the renewable energy produced by the company owned wind projects.

IV. FUTURE COST IMPACT FOR THE RES AND SES (2020-2034)

Future RES rate impacts were derived by comparing NSP electric system cost projections within the Strategist computer modeling for two different futures: 1) a "RES" future that reflects the Reference Case in the 2020-2034 Resource Plan, and, 2) a "No RES" future in which all renewable generation capacity (MW) and energy (MWh) contained in the "RES" future case are removed and replaced with non-renewable generation. In this case, the costs and benefits of all RES eligible resources are reflected as impacts of the RES. We note that, in many cases, including our recent acquisitions of wind energy, we would have pursed additions of renewable resources even in the absence of the RES.

The 2011 Legislation, requesting a report "estimating rate impacts resulting from utility actions taken to comply with the renewable energy objectives of the state", could not have anticipated the short amount of time it would take before the IRP computer modeling would select renewable generation over non-renewable generation in many cases. The "No RES" and "No SES" cases necessitate non-renewable generation to be forced into the modeling.

As stated, the "RES" case is represented by the "Reference Case" that is discussed throughout this Resource Plan document. Modeling assumptions and inputs (e.g., fuel prices, generic resource costs, sales forecast, externality costs, etc.) can be found in Attachment A, Section IV: Modeling Assumptions and Inputs of the Resource Plan Supplement document, and unit sizes and retirements can be found in Attachment A, Section V: Resource Options. The "Reference Case" assigns a cost to CO_2 emissions of $25.00/ton starting in 2025 and escalates annually at the inflation rate; this value also represents the avoided costs of CO2 attributed to renewables.

By taking the difference between the annual system costs of the "RES" and "No RES" cases, one can estimate the future costs (or savings) associated with all of the Company's actions to comply with the RES. It is important to emphasize that this comparison of a "RES" future and "No RES" future produces RES rate impact estimates that are the result of all of the Company's renewable generation resources, both those that exist on our system today as well additional future renewables contained in the "Reference Case" that are projected to be added through 2034, including those that are needed to maintain compliance with the RES and SES. As a result, the future rate impacts identified in this report are for all renewable resources and may be markedly different from rate impacts calculated for incremental renewable resources.

Future SES rate impacts were derived in a manner similar to that described above for future RES rate impacts.

V. DIRECT COSTS

The Company's direct costs reflect power purchase agreement payments and revenue requirements for owned facilities, the avoided market energy costs, and avoided market capacity costs associated with the energy and capacity of the resource, and market revenues received from these projects.

Using the direct costs, the Company determined the total RES and SES net costs, inclusive of the PPA generation costs, minus the market revenues associated with those projects, compared to the avoided energy and capacity costs. If the owned and PPA generation costs and associated market revenues views were smaller than the avoided energy and capacity costs, there was a net rate benefit. Conversely, if the owned and PPA generation costs and associated market revenues were larger than the avoided energy and capacity costs, then there was a net rate cost.

VI. INDIRECT COSTS

Appendix Q of the 7/1/2019 filing presented the NSP Wind & Solar Integration Study. The Company hired Enternex to quantify indirect costs associated with adding variable generation, such as base load cycling and ancillary services.

In response to low power market prices, and the increasing penetration of renewables, the Company has identified actions to make traditional baseload generation more flexible, and avoid periods of high renewable production and low market prices. This includes the changes related to self-commitment and seasonal operations at our coal units.

VII. FUTURE TRANSMISSION COSTS

The Company has included transmission costs associated with RES and SES resources using the costs associated with new projects consistent with our assumptions in our IRP modeling. The RES Costs and SES Costs reflect the total capital revenue requirement for future projects, inclusive of transmission costs.

VIII. PERMITTING AND EMISSION COSTS

The Company has applied a cost to CO2 emissions of $25.00/ton starting in 2025 and escalates annually at the inflation rate; this value also represents the avoided costs of

CO_2 attributed to renewable resource additions. Externality costs are not included in the rate impact consistent with the Commission's Order.[1]

IX. SUMMARY

All RES-eligible and SES-eligible projects were included in this cost analysis of compliance with the RES. Overall, the impact of the RES shows a net benefit on a levelized basis.

[1] ORDER ESTABLISHING UNIFORM REPORTING SYSTEM FOR ESTIMATING RATE IMPACT OF MINN. STAT. § 216B.169, Docket No. E999/CI-11-852 (January 6, 2015) (However, compliance cost estimates should not incorporate the benefit of avoiding emissions where those benefits are not now, and not expected to be, reflected in rates.)

Table 1: Annualized Current Period RES Rate Impact (2014-2019)

	Current Period					
RES Generation	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Total RES Generation PPA & Owned (GWh)	8,376	8,341	10,223	11,540	10,149	10,211
Costs associated with RES generation including Transmission	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Total RES Costs (millions)	$541	$562	$559	$593	$543	$548
Total cost for RES generation ($/MWh)	$64.58	$67.43	$54.72	$51.39	$53.48	$53.62
Avoided Costs due to RES	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Avoided energy costs PPAs & Owned (millions)	$291	$195	$223	$292	$306	$243
Avoided capacity cost PPAs & Owned (millions)	$33	$35	$43	$55	$59	$54
Avoided transmission cost (millions)	$15	$16	$20	$25	$33	$30
Avoided emission cost PPAs & Owned (millions)	$0	$0	$0	$0	$0	$0
Total avoided costs PPAs & Owned (millions)	$338	$246	$286	$372	$398	$326
Total avoided costs PPAs & Owned ($/MWh)	$40.37	$29.51	$27.99	$32.22	$39.24	$31.97
Total RES premium/discount (millions)	$203	$316	$273	$221	$144	$221
Total RES premium/discount ($/MWh)	$24.21	$37.92	$26.73	$19.17	$14.24	$21.65
	Current Period					
Annualized RES Rate Impacts	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
NSP total retail sales (GWh)	41,861	41,267	41,263	40,793	41,896	40,523
NSP retail rate impact ($/MWh)	$4.84	$7.66	$6.62	$5.42	$3.45	$5.46
NSP retail rate impact (cents/kWh)	.48¢	.77¢	.66¢	.54¢	.34¢	.55¢

Table 2: Annualized Current Period SES Rate Impact (2017-2019)

	Current Period		
SES Generation	**2017**	**2018**	**2019**
Total SES Generation (GWh)	439	496	507
Costs associated with SES generation including Transmission	**2017**	**2018**	**2019**
Total SES Costs (millions)	$31	$37	$35
Total cost for SES generation ($/MWh)	$70.28	$75.35	$69.29
Avoided Costs due to SES	**2017**	**2018**	**2019**
Avoided energy costs due to SES (millions)	$13	$16	$12
Avoided capacity cost due to SES (millions)	$9	$13	$11
Avoided transmission cost (millions)	$0	$0	$0
Avoided emission cost due to SES (millions)	$0	$0	$0
Total avoided costs due to SES (millions)	$22	$29	$23
Total avoided costs SES ($/MWh)	$50.90	$57.80	$45.31
Total SES premium/discount (millions)	$9	$9	$12
Total SES premium/discount ($/MWh)	$19.38	$17.56	$23.98
	Current Period		
Annualized SES Rate Impacts	**2014**	**2018**	**2019**
NSP total retail sales (GWh)	40,793	41,896	40,523
NSP retail rate impact ($/MWh)	$0.21	$0.21	$0.30
NSP retail rate impact (cents/kWh)	.02¢	.02¢	.03¢

Table 3: Annualized Future RES Rate Impact (2020-2034) – Part 1 (2020-2026)

	Future Period						
RES Generation	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Total RES Generation PPA & Owned (GWh)	13,950	16,831	18,047	17,441	17,216	17,096	17,961
Costs associated with RES generation including Transmission	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Total RES Costs (millions)	$604	$633	$649	$608	$604	$589	$618
Total cost for RES generation ($/MWh)	$43.28	$37.62	$35.97	$34.86	$35.07	$34.43	$34.40
Avoided Costs due to RES	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Avoided energy costs PPAs & Owned (millions)	$469	$499	$526	$502	$496	$498	$527
Avoided capacity cost PPAs & Owned (millions)	$66	$77	$83	$81	$82	$83	$103
Avoided transmission cost (millions)	$9	$12	$11	$15	$16	$15	$15
Avoided emission cost PPAs & Owned (millions)	$0	$0	$0	$0	$0	$44	$43
Total avoided costs PPAs & Owned (millions)	$543	$588	$620	$599	$593	$640	$687
Total avoided costs PPAs & Owned ($/MWh)	$38.96	$34.91	$34.36	$34.33	$34.47	$37	$38
Total RES premium/discount (millions)	$60	$46	$29	$9	$10	-$52	-$69
Total RES premium/discount ($/MWh)	$4.32	$2.71	$1.61	$0.53	$0.61	-$3	-$4
	Future Period						
Annualized RES Rate Impacts	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
NSP total retail sales (GWh)	40,079	39,606	39,530	39,330	39,355	39,169	38,983
NSP retail rate impact ($/MWh)	$1.50	$1.15	$0.73	$0.24	$0.27	-$1.32	-$1.78
NSP retail rate impact (cents/kWh)	.15¢	.12¢	.07¢	.02¢	.03¢	-.13¢	-.18¢

Table 3: Annualized Future RES Rate Impact (2020-2034) – Part 2 (2027-2034)

	Future Period							
RES Generation	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Total RES Generation PPA & Owned (GWh)	18,561	18,438	17,983	19,861	25,756	30,841	33,794	35,422
Costs associated with RES generation including Transmission	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Total RES Costs (millions)	$615	$577	$549	$774	$1,079	$1,347	$1,472	$1,578
Total cost for RES generation ($/MWh)	$33.14	$31.29	$30.54	$38.95	$41.90	$43.68	$43.57	$44.56
Avoided Costs due to RES	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Avoided energy costs PPAs & Owned (millions)	$539	$505	$478	$706	$1,018	$1,286	$1,411	$1,518
Avoided capacity cost PPAs & Owned (millions)	$121	$118	$116	$149	$204	$242	$273	$306
Avoided transmission cost (millions)	$14	$14	$13	$13	$12	$12	$11	$11
Avoided emission cost PPAs & Owned (millions)	$71	$66	$57	$79	$103	$113	$127	$149
Total avoided costs PPAs & Owned (millions)	$745	$703	$665	$946	$1,338	$1,654	$1,822	$1,984
Total avoided costs PPAs & Owned ($/MWh)	$40	$38	$37	$48	$52	$54	$54	$56
Total RES premium/discount (millions)	-$130	-$126	-$115	-$173	-$258	-$306	-$349	-$406
Total RES premium/discount ($/MWh)	-$7	-$7	-$6	-$9	-$10	-$10	-$10	-$11
	Future Period							
Annualized RES Rate Impacts	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
NSP total retail sales (GWh)	38,906	38,996	38,506	38,442	38,373	38,638	39,028	39,289
NSP retail rate impact ($/MWh)	-$3.33	-$3.24	-$3.00	-$4.49	-$6.73	-$7.93	-$8.95	-$10.33
NSP retail rate impact (cents/kWh)	-.33¢	-.32¢	-.30¢	-.45¢	-.67¢	-.79¢	-.90¢	-1.03¢

Table 4: Annualized Future SES Rate Impact (2020-2034) – Part 1 (2020-2026)

	Future Period						
SES Generation	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Total SES Generation (GWh)	537	559	579	598	619	637	1,620
Costs associated with SES generation including Transmission	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Total SES Costs (millions)	$37	$38	$39	$40	$41	$43	$87
Total cost for SES generation ($/MWh)	$68.08	$67.43	$67.18	$67.04	$66.98	$66.96	$53.83
Avoided Costs due to SES	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Avoided energy costs due to SES (millions)	$12	$12	$14	$15	$16	$26	$68
Avoided capacity cost due to SES (millions)	$12	$13	$13	$14	$14	$14	$33
Avoided transmission cost (millions)	$0	$0	$0	$0	$0	$0	$0
Avoided emission cost due to SES (millions)	$0	$0	$0	$0	$0	$2	$9
Total avoided costs due to SES (millions)	$24	$25	$27	$29	$31	$42	$110
Total avoided costs SES ($/MWh)	$44.75	$44.50	$46.52	$49.09	$49.55	$67	$68
Total SES premium/discount (millions)	$13	$13	$12	$11	$11	$0	-$22
Total SES premium/discount ($/MWh)	$23.33	$22.94	$20.66	$17.95	$17.43	$0	-$14
	Future Period						
Annualized SES Rate Impacts	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
NSP total retail sales (GWh)	40,079	39,606	39,530	39,330	39,355	39,169	38,983
NSP retail rate impact ($/MWh)	$0.31	$0.32	$0.30	$0.27	$0.27	$0.01	-$0.58
NSP retail rate impact (cents/kWh)	.03¢	.03¢	.03¢	.03¢	.03¢	.00¢	-.06¢

Table 4: Annualized Future SES Rate Impact (2020-2034) – Part 2 (2027-2034)

	Future Period							
SES Generation	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Total SES Generation (GWh)	2,603	2,628	2,641	4,587	7,497	9,465	11,387	13,333
Costs associated with SES generation including Transmission	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Total SES Costs (millions)	$133	$136	$139	$229	$365	$462	$560	$662
Total cost for SES generation ($/MWh)	$50.98	$51.80	$52.64	$49.87	$48.69	$48.85	$49.20	$49.68
Avoided Costs due to SES	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Avoided energy costs due to SES (millions)	$113	$116	$120	$221	$371	$477	$578	$693
Avoided capacity cost due to SES (millions)	$51	$50	$48	$80	$125	$150	$173	$206
Avoided transmission cost (millions)	$0	$0	$0	$0	$0	$0	$0	$0
Avoided emission cost due to SES (millions)	$18	$18	$17	$33	$53	$56	$67	$82
Total avoided costs due to SES (millions)	$182	$183	$185	$334	$549	$683	$818	$981
Total avoided costs SES ($/MWh)	$70	$70	$70	$73	$73	$72	$72	$74
Total SES premium/discount (millions)	-$49	-$47	-$46	-$105	-$184	-$221	-$258	-$319
Total SES premium/discount ($/MWh)	-$19	-$18	-$17	-$23	-$24	-$23	-$23	-$24
	Future Period							
Annualized SES Rate Impacts	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
NSP total retail sales (GWh)	38,906	38,996	38,506	38,442	38,373	38,638	39,028	39,289
NSP retail rate impact ($/MWh)	-$1.26	-$1.21	-$1.19	-$2.74	-$4.78	-$5.71	-$6.60	-$8.12
NSP retail rate impact (cents/kWh)	-.13¢	-.12¢	-.12¢	-.27¢	-.48¢	-.57¢	-.66¢	-.81¢

Table 5: Levelized Annual RES Rate Impact

	Current Period	Future Period
Levelized RES Generation	**2014-2019**	**2020-2034**
Total RES Generation (GWh)	9,720	19,875
Levelized Costs associated with RES generation	**2014-2019**	**2020-2034**
Total RES Costs (millions)	$558	$753
Total cost for RES generation ($/MWh)	$57	$38
Levelized Avoided Costs due to RES	**2014-2019**	**2020-2034**
Avoided energy costs due to RES (millions)	$257	$658
Avoided capacity cost due to RES (millions)	$45	$123
Avoided transmission cost (millions)	$22	$13
Avoided emission cost due to RES (millions)	$0	$44
Total avoided costs due to RES (millions)	$325	$838
Total avoided costs RES ($/MWh)	$33	$42
Levelized Total RES premium/discount (millions)	$232	-$85
Levelized Total RES premium/discount ($/MWh)	$24	-$4
	Current Period	Future Period
Levelized RES Rate Impacts	**2014-2019**	**2020-2034**
NSP total retail sales (GWh)	41,295	39,178
NSP retail rate impact ($/MWh)	$5.62	-$2.17
NSP retail rate impact (cents/kWh)	.56¢	-.22¢

Table 6: Levelized Annual SES Rate Impact

	Current Period	Future Period
Levelized SES Generation	**2017-2019**	**2020-2034**
Total SES Generation (GWh)	479	2,999
Levelized Costs associated with SES generation	**2017-2019**	**2020-2034**
Total SES Costs (millions)	$34	$155
Total cost for SES generation ($/MWh)	$72	$52
Levelized Avoided Costs due to SES	**2017-2019**	**2020-2034**
Avoided energy costs due to SES (millions)	$14	$140
Avoided capacity cost due to SES (millions)	$11	$52
Avoided transmission cost (millions)	$0	$0
Avoided emission cost due to SES (millions)	$0	$17
Total avoided costs due to SES (millions)	$25	$209
Total avoided costs SES ($/MWh)	$51	$70
Levelized Total SES premium/discount (millions)	$10	-$54
Levelized Total SES premium/discount ($/MWh)	$20	-$18
	Current Period	Future Period
Levelized SES Rate Impacts	**2017-2019**	**2020-2034**
NSP total retail sales (GWh)	41,076	39,178
NSP retail rate impact ($/MWh)	$0.24	-$1.39
NSP retail rate impact (cents/kWh)	.02¢	-.14¢

Table 7: Transmission Projects Attributable to the RES

2003 RCR **M-02-474**	**2004 RCR** **M-03-1882**	**2005 RCR** **M-05-289**	**2007 TCR, RCR Compliance** **M-06-1505**
425MW Throughput from SW M	Chanarambie Substation and 115kV System Improvements Between Pipestone, Chanarambie, Lake Yankton, and Lyon County Substation	Alexandria to Douglas County 115kV	825 WIND UPGRADE - MAIN PROJECT
Split Rock / Lakefield Junction 34	Black Dog Substation Transformer Replacement	Willmar to Kerkhoven Tap 115 kV	*Split Rock-Nobles Co- Lakefield Junction 345 kV line*
825MW Buffalo Ridge / White / Heron	345 kV Line Clearance Improvements from Wilmarth Substation to Lakefield junction Substation	Minnesota Valley to Franklin 115 kV	*Buffalo Ridge- Yankee- Brookings Co 115 kV line*
825MW Lyon / Franklin / Ft. Ridge	69 kV Line Upgrade from Bird Island Substation to Franklin Substation	Paynesville to Wakefield 115 kV	*Brookings Co- White 345 kV line*
825MW Reconductor Only	115 kV Line Upgrade from Summit Substation to Loon Tap to West Faribault Substation	Upgrades to Marshall Municipal Utilities 115 kV System	*Chanarambie- Fenton- Nobles Co 115 kV line*
	Troy Switching Substation	Lakefield Junction to Fox Lake 161 kVLine	*Red Wood Falls Junction- Franklin 115 kV upgrade*
	GM, LLC Project		*Brookings Co Substation*
	Wind Generator Interconnects on the 35 kV System in Southwestern Minnesota		*Split Rock Substation*
			Lakefield Junction Substation
			White Substation
			Nobles Co Substation
			Chanarambie Substation
			Buffalo Ridge Substation
			YANKEE 200 MW WIND GENERATION COLLECTOR STATION
			FENTON WIND GENERATION COLLECTOR STATION
			SERIES CAPACITOR STATION
			NOBLES COUNTY COLLECTOR
			ROCK COUNTY COLLECTOR
2008 TCR **M-07-1156**	**2010 TCR** **M-09-1048**	**2011 TCR** **M-10-1064**	
BRIGO Transmission Lines	Blue Lake - Wilmarth - Lakefield Transmission	CAPX2020 - Brookings	LaCrosse Madison
Spare Wind Transformer	Nobles Wind Farm Network Upgrade transmission Project		Big Stone - Brookings
	161 kV Line Pleasant Valley Sub to Byron (SE MN)		

Table 8: Transmission Project Costs Attributable to the RES
(70% of MVP Project Annual Revenue Requirements Assigned to RES)

Project Revenue Requirements - Total Company ($ millions)	M-02-474	M-03-1882	M-05-289	M-06-1505	M-07-1156	M-09-1048	M-10-1064	M-12-050	2016 TCR	Total
2005	$27.5	$6.8	$0.9	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$35.2
2006	$43.6	$6.1	$1.7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$51.4
2007	$50.6	$5.9	$1.5	$18.4	$0.0	$0.0	($0.0)	$0.0	$0.0	$76.4
2008	$50.4	$5.7	$1.5	$28.4	$1.1	$0.0	$0.0	$0.0	$0.0	$87.0
2009	$48.8	$5.5	$1.4	$28.2	$6.1	$0.3	$0.0	$0.0	$0.0	$90.4
2010	$47.3	$5.4	$1.4	$27.2	$8.7	$1.4	$0.0	$1.4	$0.0	$92.8
2011	$45.8	$5.2	$1.3	$26.2	$8.3	$1.8	$0.0	$2.4	$0.0	$91.1
2012	$44.4	$5.1	$1.3	$25.3	$8.0	$1.8	$0.5	$2.3	$0.0	$88.6
2013	$43.1	$4.9	$1.2	$24.4	$7.7	$1.7	$1.5	$2.2	$0.0	$86.7
2014	$41.7	$4.7	$1.2	$23.6	$7.4	$1.7	$2.9	$2.1	$0.0	$85.3
2015	$40.4	$4.6	$1.1	$22.7	$7.2	$1.6	$3.8	$2.0	$0.0	$83.4
2016	$39.0	$4.4	$1.1	$21.9	$6.9	$1.6	$3.7	$2.0	$0.0	$80.6
2017	$37.7	$4.3	$1.0	$21.0	$6.6	$1.5	$3.6	$1.9	$0.1	$77.7
2018	$36.3	$4.1	$1.0	$20.2	$6.3	$1.5	$3.5	$1.8	$0.7	$75.4
2019	$35.0	$4.0	$0.9	$19.4	$6.1	$1.4	$3.7	$1.7	$2.5	$74.6
2020	$33.6	$3.8	$0.9	$18.5	$5.8	$1.4	$3.3	$1.7	$2.4	$71.4
2021	$32.3	$3.6	$0.9	$17.7	$5.5	$1.3	$3.2	$1.6	$2.3	$68.4
2022	$30.9	$3.5	$0.8	$16.9	$5.3	$1.3	$3.1	$1.5	$2.3	$65.6
2023	$29.7	$3.3	$0.8	$16.4	$5.0	$1.2	$3.0	$1.4	$2.2	$63.1
2024	$28.5	$3.2	$0.8	$16.1	$4.8	$1.2	$2.9	$1.4	$2.2	$60.9
2025	$27.4	$3.1	$0.7	$15.7	$4.7	$1.1	$2.8	$1.3	$2.2	$59.1
2026	$26.5	$3.0	$0.7	$15.4	$4.6	$1.1	$2.7	$1.3	$2.1	$57.5
2027	$25.8	$2.9	$0.7	$15.1	$4.4	$1.1	$2.6	$1.2	$2.1	$56.1
2028	$25.2	$2.9	$0.7	$14.8	$4.3	$1.1	$2.5	$1.2	$2.1	$54.7
2029	$24.6	$2.8	$0.7	$14.4	$4.2	$1.0	$2.4	$1.2	$2.1	$53.4
2030	$23.8	$2.7	$0.6	$14.0	$4.1	$1.0	$2.3	$1.1	$2.0	$51.7
2031	$23.0	$2.6	$0.6	$13.5	$4.0	$1.0	$2.3	$1.1	$1.9	$50.0
2032	$22.3	$2.5	$0.6	$13.1	$3.8	$0.9	$2.2	$1.1	$1.9	$48.3
2033	$21.5	$2.4	$0.6	$12.6	$3.7	$0.9	$2.1	$1.0	$1.8	$46.7
2034	$20.8	$2.3	$0.6	$12.2	$3.6	$0.9	$2.1	$1.0	$1.7	$45.2
Total	$1,027.3	$121.4	$28.9	$533.3	$148.3	$32.8	$63.0	$39.0	$34.7	$2,028.8

Table 9: MISO Data Used in RES Avoided Energy and Capacity Calculations

	Future Period							Future Period							
Avoided Capacity Cost Details	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
MISO Accredited Capacity of Renewables (MW)[1]	886	1,017	1,072	1,030	1,017	1,014	1,227	1,410	1,350	1,305	1,640	2,206	2,566	2,830	3,117
Avoided Capacity ($000/MW-Year)	$74	$76	$78	$79	$81	$82	$84	$86	$87	$89	$91	$93	$94	$96	$98
Total Avoided Capacity Costs due to RES (millions)	$66	$77	$83	$81	$82	$83	$103	$121	$118	$116	$149	$204	$242	$273	$306

Avoided Energy Cost Details	Future Avoided Energy Costs determined using Strategist model

[1] No avoided capacity costs calculated due to generic renewable costs being accounted for in avoided energy

Table 10: MISO Data Used in SES Avoided Energy and Capacity Calculations

	Future Period							Future Period							
Avoided Capacity Cost Details	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
MISO Accredited Capacity of Renewables (MW)[1]	158	165	172	178	177	176	394	591	568	545	881	1,346	1,591	1,795	2,098
Avoided Capacity ($000/MW-Year)	$74	$76	$78	$79	$81	$82	$84	$86	$87	$89	$91	$93	$94	$96	$98
Total Avoided Capacity Costs due to SES (millions)	$12	$13	$13	$14	$14	$14	$33	$51	$50	$48	$80	$125	$150	$173	$206

Avoided Energy Cost Details	Future Avoided Energy Costs determined using Strategist model

[1] No avoided capacity costs calculated due to generic renewable costs being accounted for in avoided energy

INCLUSION, DIVERSITY, AND EQUITY

As a leading business in Minnesota, we are committed to the principles of greater inclusion, diversity and equity in our company and community. The recent nationwide unrest and ongoing protests demanding change to address systemic racism have only strengthened our resolve to find ways we can do more to help our employees and communities heal, recover and grow. Our Chief Executive Officer (CEO), Ben Fowke joined more than 50 Minnesota executive leaders in co-signing a letter released by Children's Minnesota, stating their commitment to "stand united against acts of racism."[1] As stated by EEI President Tom Kuhn, "While we have made great progress in advancing diversity and inclusion within our industry, we recognize that we can—and we must—do more." As such, the Xcel Energy leadership team is working to have direct conversations with employees and stakeholders about these issues, and solutions on which we can act. We remain committed to continued support and development of a diverse workforce that reflects the communities and customers we serve by reviewing our current processes to ensure we are meeting those commitments.

More narrowly, as part of our Integrated Resource Planning process and various regulatory dockets, we have worked closely with stakeholder groups to elaborate and expand on how the Company embraces customer equity, workforce inclusion and diversity, and a just and equitable workforce transition to a clean energy future. We utilize this Attachment to explain what we do to advance these values and how we are interacting with stakeholders to pursue improvements and new programs.

Specifically, we focus on a series of topics brought forward in discussions with Fresh Energy and the Sierra Club. We note, however, this is by no means an exhaustive summary of what we do at Xcel Energy to further these values. Finally, we note that while we wanted to provide a holistic discussion in one place to be responsive to stakeholder discussions, this docket is not necessarily the best place for further discussion on all of these topics (for instance, there are separate dockets that include discussions about workforce diversity, energy efficiency, solar*rewards, and electrification[2]).

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[1] https://www.tdworld.com/careers/article/21133193/utilities-respond-to-national-protests-to-reinforce-commitments-to-diversity-and-inclusivity
[2] All relevant docket information for each topic is included in each section within this document.

I. WORKFORCE – INCLUSION AND DIVERSITY, AND EQUITABLE TRANSITION TO A CLEAN ENERGY FUTURE

A. Cultivating a Diverse and Inclusive Workforce

Our workforce strategy begins with a mission to attract, retain and develop the highest quality talent. We take a proactive approach to workforce planning and are identifying the skills we need to prepare and meet our future energy objectives, aligning our talent strategies to build diverse pipelines and identifying opportunities to retrain or develop our workforce. Further, we believe that an inclusive and diverse workforce makes our company stronger – and our commitment goes beyond human resources (HR) policies and practices – it is an integral part of who we are, how we operate, and how we see our future.

Our current high-level workforce diversity and inclusion goals, on which we track progress quarterly are as follows:

1. *Increase Minority and Female Representation*

At the end of 2019, Xcel Energy's female representation was 23 percent of the workforce and minority representation was 15.4 percent of the workforce. Through strategic hiring practices, partnerships with organizations such as the Center for Energy Workforce Development, and work with our business resource groups, we aim to increase these numbers over the coming years to ensure that our workforce continues to diversify the same way our communities are diversifying.

2. *Increase Female Workforce Support and Retention*

Xcel Energy's inclusion and diversity team, business resource groups, and leadership are committed to continuing to grow a culture where all employees want to stay and grow their careers. Specifically for women, we have three business resource groups – Growth and Retention of Women in Non-Traditional Roles (GROW), Women's Interests Network (WIN), and Women in Nuclear – aimed at professional development for women, recruitment and community-building.[3] We recently

[3] All employees are also supported by other business resource groups including: Employee Connection Network (ECN); General Counsel's Employee Excellence and Equality Committee (GC EEE); GenNEXT, providing opportunities for employee education, collaboration and development; Military Ombudsmen for Veterans and Employees (MOVE); Supportive Association for GLBTA Employees at Xcel Energy (SAGE); Strategic Organization Utilizing Resources for Career Enhancement (SOURCE); Tribal Wind, an inclusive group supporting Native American employees; and, XCELENTE, Xcel Energy's Latino Business Resource Group.

implemented a new leave policy for new parents aimed at giving additional time for new parents to bond with their new children, which will also decrease the "motherhood tax" by opening it up to all caregivers.

3. Increase Minority and Female Representation in Leadership

Xcel Energy is looking at all of our talent processes, from recruiting, to performance management, to succession planning to ensure no bias exists. We also bring these topics up with leaders when they are hiring and evaluating their teams. At the end of 2019, Xcel Energy's female representation of leaders was 20.7 percent and minority representation of leaders was 9.8 percent.

4. Ensure Inclusive Work Environment

Over the past several years we have been working to educate all of our employees about micro-inequities and unconscious bias. As an organization who signed on to the CEO Action for Inclusion and Diversity,[4] we know this is one of the key tenets to helping continue to drive an inclusive culture. To date, we have educated over 60 percent of our workforce on micro-inequities and unconscious biases. Also, we are using our employee engagement survey process to understand the feelings of inclusion within different parts of the organization. Specifically, we look at scores on belonging, authenticity, recognition, empowerment, and the ability to speak up, and compare those scores across demographics to understand if there are areas in the organization where people are not feeling included. We established our baseline scores on this "inclusion index" in June 2019, and plan on tracking progress every time we do an employee engagement survey.

To achieve our goals, we leverage the Center for Energy Workforce Development (CEWD) framework and its three components to diversity, which we are a leader in deploying. The CEWD framework focuses on the following objectives:

- *Education.* Implement clearly defined education solutions that link industry-recognized competencies and credentials to employment opportunities and advancement in the energy industry.
- *Workforce Planning.* Balance the supply and demand for a qualified and diverse energy workforce.
- *Career Awareness.* Create awareness among students, parents, educators, and non-traditional workers of the critical need for a skilled energy workforce and the opportunities for education that and lead to entry level employment.

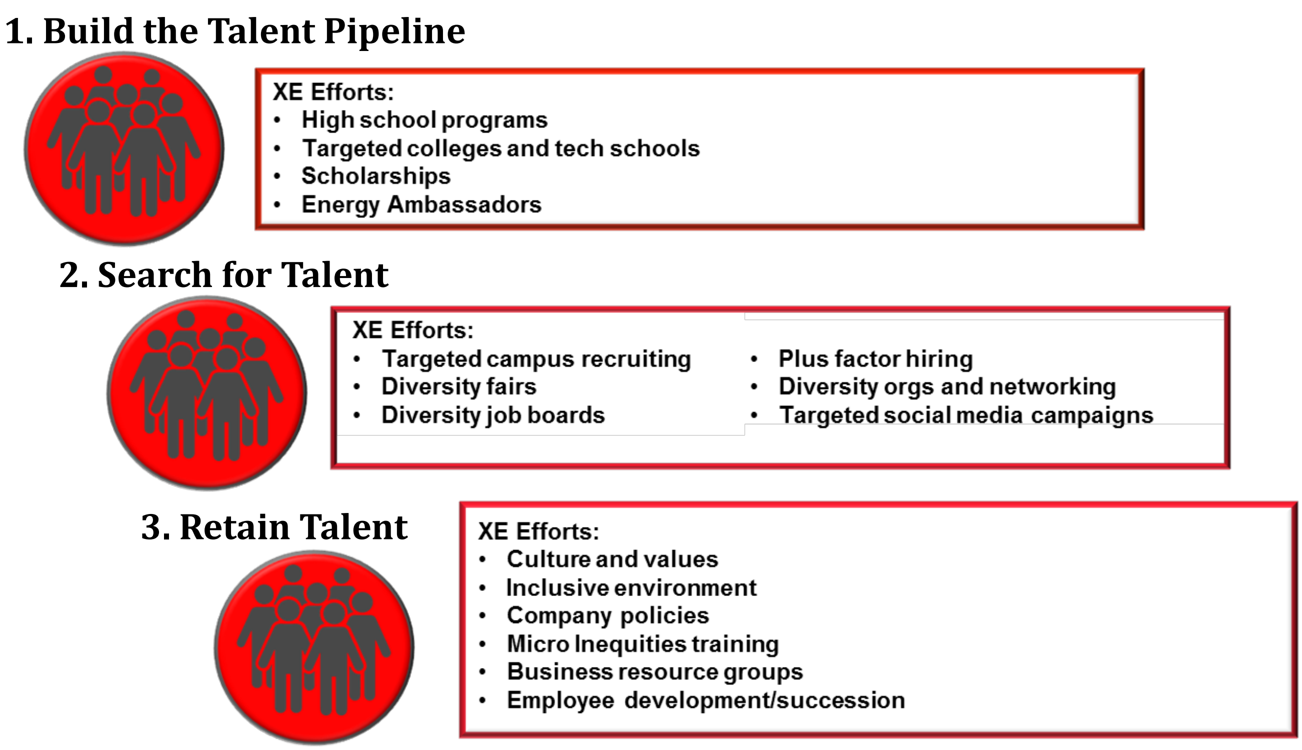
[4] *See* CEO Action Pledge here: https://www.ceoaction.com/pledge/ceo-pledge/

- *Structure and Support.* Organize the energy industry workforce development efforts to maximize the effectiveness of national, state, and individual company initiatives.

The CEWD components to diversity are: (1) build the talent pipeline, (2) search for talent, and (3) retain talent. Xcel Energy invests significant time and effort into each of these components.

We outline below, examples of our efforts in the CEWD diversity component areas, as also shared with the Energy Utility Diversity Group (EUDG) in an August 26, 2019 presentation.[5]

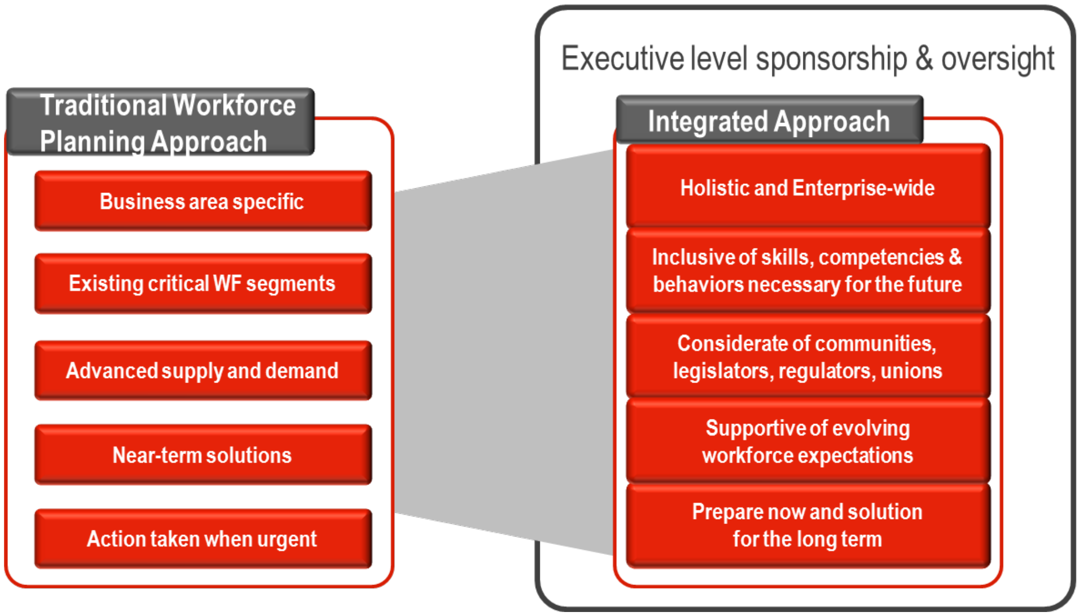
Figure 1: CEWD Three Components to Diversity – Xcel Energy Example Efforts



Finally, we have recognized key partnerships to lead us in the future, and expanded the value of strategic workforce planning to achieve our vision, as follows:

[5] Docket No. E,G999/CI-19-336

Figure 2: Expanding the Value of Strategic Workforce Planning



While we are starting to see progress, and have received some recognition for our achievements,[6] we realize this is a journey. We recognize that an inclusive and diverse workforce is an integral part of who we are, how we operate, and how we see our future – and we are committed to continuing the work necessary to achieve our vision.

B. Ensuring a Just and Equitable Workforce Transition

This Resource Plan proposes the retirement of our entire coal fleet by 2030; while the plans for our Sherco and King plant sites are still being developed, Xcel Energy has an incredibly strong history as a Company of both working with host communities and helping impacted employees transition to new opportunities in other parts of the organization. For example, in the 2017 Colorado Energy Plan (CEP), our affiliate Public Service Company of Colorado (PSCo) announced the early retirement of 660MW of coal-fired generation at our Comanche Generating Station in Pueblo, Colorado and replacement with 1,800 MW of new renewables, 275 MW of storage, and 383 MW of existing natural gas generation. The CEP stipulates the retirement of Unit 1 (325 MW) in 2022 and Unit 2 (335 MW) in 2025 – both of which have been in operation since the mid-1970s, and, in total, currently employ approximately 156 full

[6] Some of the external recognition we have received includes: Military Friendly Gold 2020, Top 10 Military Friendly Employer; 2019 Military Times, Best for Vets Employers; 2019 and 2020 Best Places to Work for LGBTQ Equality; and, 4 years of perfect 100 scores on the Human Rights Campaign's Corporate Equality Index.

time employees.

While Unit 3 (750 MW) does not yet have a set retirement date, we anticipate the staffing needs to drop to almost half the current level by 2025 when Unit 2 closes. If left unaddressed, the retirement of these Units and reduced workforce need would have a significant economic and societal impact on the Pueblo community. Therefore, in partnership with stakeholders, legislators, and the community we have designed and are implementing a transition plan for the Pueblo community. The plan revolves around direct investment, internal skill building, partnerships, and external skill building.

Closer to home, we have a similar record in helping our employees transition from plant closures. For instance, during the Metro Emissions Reduction Project (MERP) in 2008, when we closed coal operation at Riverside and High Bridge we found all union employees other opportunities. More recently, in 2012, when we shut down coal operation at Black Dog, all of our union employees were moved to other plants or other areas within the company i.e., Relay/Breaker, Substation Construction, and Transmission. Xcel Energy prides itself on never having laid off an employee as a result of closing a coal plant and intends to maintain that record.

1. *Transitions at the Sherco and King Plants*

While transition plans for impacted employees our Sherco and King plants are still under development, we have done significant planning for the transition and have been in regular communications with plant employees. We expect no Xcel Energy employee will be laid off as a result of the plant closures at Sherco and King. We expect attrition and retirement will outweigh our staffing needs at those plants. Impacted workers will be able to leverage internal and external resources to upskill or reskill in order to transition into other positions in the Company. There will be opportunities for impacted employees at the plants within Xcel Energy, at locations nearby King and Sherco, or across the state of Minnesota.

We have conducted analysis to estimate the number of potential impacted employees and the resources necessary to transition those employees. Working with our Energy Supply resource management team, we estimated the number of Xcel Energy employees that would, at a minimum, be needed to staff each plant over time. We based this on our proposed retirement dates compared to attrition projections to arrive at a total count of employees that may need transition resources at the time of Unit retirement. The second step was to identify potential transition resources that include, but are not limited to, internal technical training, internal enterprise-wide learning courses, tuition reimbursement, relocation reimbursement, retention/ premium pay, and external micro-credentials reimbursement, etc. Based on the total cost of the combined transition resources applied to the total number of potentially affected workers for Sherco and King, we estimate employee transition costs of approximately $1.8 million. We note that this estimate will be updated as more refined inputs become available and as the plants approach their retirement dates.

Plant Managers have been engaging with employees regarding the future of our coal generators for several years. These communications have explained that the generation business is changing due to the significant additions of renewable energy on the system, low natural gas prices, and societal goals to reduce carbon emissions. As part of those communications, we discussed the likelihood that coal plants would shut down before their expected retirement dates. We conducted these communications through plant meetings, small group meetings, individual discussions, and emails.

We will continue developing plans for the transition at Sherco and King using the same general approach to workforce and community transition we used at our Comanche plant. However, community transition and solutions will be unique to each community and driven by the community and their vision for the future. Xcel Energy has a long history of partnering with communities we operate in to help them reach their vision. We have invested in our workforce through multi-year apprenticeships, technical, and on-the-job training, and – to the extent feasible – we anticipate retaining and transitioning our skilled workers to other opportunities across the Company.

While the exact details of the Sherco and King plans are still being developed, we have started the initial steps by engaging with each community. With our Sherco plans being further along, we have helped to draw new investment to the Becker area, including Northern Metals Recycling, the Company's planned combined cycle unit at the Sherco plant, and a potential Google data center. We have developed strong relationships with our host communities and understand the significant economic impact our plants have on the local economies as demonstrated in the Host Community Study that is also part of this Resource Plan Supplement. We are committed to continuing these important relationships and assisting our host communities as we both transition away from our legacy coal-fired generation facilities and their economic footprints.

C. Commitment to Low-Income and Multifamily Energy Efficiency

The Company currently offers a series of low-income and multifamily energy efficiency programs as part of its Minnesota Conservation Improvement Program (CIP). Our low-income programs have a minimum statutory spending requirement, which the Company has consistently met with ease – and has most recently proposed to double beginning in 2021. We discuss these programs and our proposal below.

1. *Home Energy Savings Program (HESP)*

This program identifies achievable energy savings and efficiency upgrades for income-qualified customers living in single family homes and 1-4 unit rental properties – with the end goal being reduced energy usage and therefore a reduced energy bill burden. We provide this service free of charge, through specialists that perform in-home or virtual walk-through assessments and energy usage analysis. We promote and communicate this program through the Company's partner vendors, advertising campaigns, and Xcel Energy Customer Care representatives as they interact with customers.

2. *Multi-Family Energy Savings Program (MESP)*

MESP provides similar, if not identical, services to the HESP program in the resident's units, with the major difference being that MESP focuses on 5+ unit multi-family dwellings. Like HESP, this program also provides educational information for tenants about the kinds of bill savings that can be realized through simple energy efficiency measures or actions. MESP is available to buildings meeting the state's minimum guidelines for dedicated affordable housing and is promoted and communicated to building owners and property managers to ensure success toward our goal of further enabling energy efficiency upgrades in residential rental spaces.

Additionally, as part of our June 17, 2020 Relief and Recovery filing in Docket E,G999/CI-20-492, we are pursuing activities to increase available CIP services for electric and natural gas customers to lower customer bills and create jobs in the state economy. We proposed to spend twice the minimum statutory requirement on our electric and natural gas low-income programs during the 2021-2023 CIP Triennial Plan[7] period, in addition to expanding programs already underway and others we are currently evaluating – including home energy efficiency kits, rebate bonuses across several high impact products, virtual audits and inspections, and the easing of participation requirements in some programs. Increasing energy efficiency activity

[7] Docket No. E,G002/CIP-20-473

during the economic slowdown will contribute to lower bills for all customers. Further, increasing direct rebate payment opportunities for customers to replace inoperative or inefficient equipment will lead to job growth for trade services, and potentially also for our customers.

3. *Low-Income Home Energy Squad (LIHES)*

The LIHES program offers direct-install of energy-saving measures and assessment services at no cost for income-qualified customers seeking energy efficiency solutions, and ways to lower their energy bill. This program is co-branded via a partnership with CenterPoint Energy and is promoted and communicated through emails, bill-inserts, and cross-promotion with other Xcel Energy low-income programs.

D. Ensuring Equitable Customer Access to Solar Energy

We have advanced several programs to bring solar energy access to income-eligible customers and disadvantaged Minnesota communities.

1. *Solar*Rewards*

As a part of the Company's highly successful Solar*Rewards program, we worked with stakeholders, including the Minnesota Department of Commerce and Solar Industry advocates, to develop an income-qualified offering targeted directly to low-income residential or business customers. The Deputy Commissioner approved the program in late 2018, and the Company commenced the program on January 28, 2019.[8]

The program provides an upfront incentive to customers when they install solar panels on their dwellings or businesses, as well as an energy incentive per kWh produced. The upfront incentive ranges from $0.50 to $2.00 per watt of nameplate production depending on the customer class (commercial, residential, etc.), which is significantly higher than the upfront incentive paid to non-income qualified customers. The energy incentive ranges from $0.06 to $0.07 per kWh produced.

During its first year of operation, the program allocated the entirety of its approximately $2.9 million budget. This is roughly 20 percent of the total Solar*Rewards budget, which is funded via the Renewable Development Fund rider. Most applicants are commercial-sized systems – typically, multi-unit buildings,

[8] Docket No. E002/M-13-1015, Decision, Department of Commerce (November 14, 2018). Corrected December 20, 2018.

schools, and non-profits. The current program rules limit the participation of single-family residential customers, as the participant must own the home. The final allocations were to 48 commercial and 12 residential customers.

2. Low-Income Solar

In partnership with Energy CENTS Coalition (ECC) and the Dayton's Bluff Neighborhood Housing Services, among other local partners, a pilot was designed with the aim to serve more than 400 Xcel Energy customers in the Railroad Island neighborhood of St. Paul, with a combined energy efficiency and community solar garden subscription outreach effort. Unfortunately, the Company's solar garden construction partner withdrew from the project. After reviewing a wide variety of additional alternative solar options, discussed in more detail in our April 1, 2020 compliance filing in Docket No. E002/M-17-527, we concluded that we will not be able to deliver an economically-feasible solar garden at the site.

While significant barriers to low-income solar exist, the Company is eager to work with stakeholders to identify economic solutions that bring solar energy to disadvantaged communities. The Company brought forward a new Low-Income rooftop solar pilot as part of our June 17, 2020 Relief and Recovery filing in Docket No. E,G999/CI-20-492. Initial plans for this proposed $3 million program include installing nearly 100 5.5kW rooftop solar systems on low-income residential housing. The program would benefit the building residents by giving them a $30 a month bill credit as compensation for the Company's use of the building's rooftop.

E. Expansion and Widespread Adoption of Transportation Electrification

In 2019, the Company attained approval for two separate electric vehicle programs that specifically increase access to electricity as a transportation fuel in an equitable manner. We, along with various stakeholders, acknowledge the environmental and societal benefits of electric vehicles (EV), and are furthering their adoption through Docket No. E002/M-18-643. The two programs with the greatest equity benefits are the Fleet EV Service and Public Charging Pilot. Our Fleet EV Service and Public Charging pilots are targeting the installation of over 1,000 new charging ports across our Minnesota service territory. Both pilots also will support low-income communities by, among other things, enabling electric buses and a new, electric one-way car sharing service. Additionally, the expansion of our Residential EV Service will allow participation by renters, and we are in the early stages of developing a multi-unit dwelling residential charging pilot to address the needs and concerns of residential customers who rent apartments in multi-unit dwellings.

1. Fleet EV Service

Our most notable success to-date under the Fleet EV Service program is our partnership with Metro Transit on the new C-Line. This program created a new high-speed service line connecting Brooklyn Center and the North Minneapolis neighborhoods to downtown Minneapolis (and therefore the rest of the metro area) via the Penn Ave North corridor. Over half of the new Minnesota-made buses are all-electric and charged via our partnership with Metro Transit, therefore reducing diesel internal combustion engine emissions through residential neighborhoods.

2. Public Charging Pilot

Our developing pilot seeks to support both identified "corridor" fast charging and community mobility hubs – leveraging available public and private funding under both scenarios. Most notably for this Resource Plan, we are partnering with the cities of Saint Paul and Minneapolis to support installation of community mobility hubs, for which the cities have selected HOURCAR as the anchor tenant. These charging hubs may be utilized by car-sharing services, transportation network companies (e.g., Uber and Lyft), and the public – including customers who do not have EV charging capabilities at home.

As a supplement to our initial Public Charging Pilot, the Company proposed an expansion of the program in our June 17, 2020 Relief and Recovery proposal in the 20-492 docket. Specifically, we proposed to work with communities and auto dealers to site publicly-available fast charging that the utility will own and operate. The program will look to support charging in areas not currently being served by private charging companies. As we explained, increased access to public charging will make it easier to own/operate an EV for our customers, especially those who do not own homes with private garage access, or those who rent/own dwellings without the ability to add charging access. Adoption of EVs will also displace use of diesel or gasoline, which is a significant opportunity for reducing carbon and other pollutants from the transportation sector.

F. Electric Reliability and Locational Equity

The Commission's April 20, 2020 Notice in Docket No. E002/M-20-406 requested comments on locational reliability, service quality and equity metrics. While we have developed some preliminary plans, we are awaiting stakeholder feedback toward more specifics on the form these metrics may take, so we can determine data availability and the level of work – and thus the timeline that will be involved. In balancing the desire for locational and equity information, we note two challenges in developing these metrics:

1. The Company does not maintain household income information on our customers. We believe U.S. Census data provides a good source of publicly available data, but that will be more general, and we would need to somehow correlate that with our customer data in a meaningful way.
2. In an effort to ensure grid security, the Company protects certain substation and feeder information as non-public information. We are also aware of the fact that combinations of data can create other risks, including to customer privacy and confidentiality that we will be sensitive to avoid.

We note that, based on our discussions with Fresh Energy in the performance based metrics docket,[9] we have created a prototype heat map that provides reliability information by zip code, with an overlay of U.S. Census income information. We believe this provides a useful display of locational reliability paired with publicly-available income data, while also ensuring grid security and customer privacy and confidentiality.

Finally, for the customer service equity metric, we believe a similar heat-map approach could work, using Commission complaints in place of Company reliability performance. However, we look forward to stakeholder input in August 12, 2020 Comments in Docket No. E002/M-20-406 that may further identify how we could use currently available customer service data for this metric.

Conclusion

In closing, Xcel Energy is committed to the principles of greater equity, diversity and inclusion in our company and our communities. We have worked closely with stakeholder groups to elaborate and expand on how the Company embraces these values, and we are proud of the work we have done to-date. However, while we have made great progress in advancing equity, diversity, and inclusion, we know we can – and will – do more.

[9] Docket No. E002/CI-17-401

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May 29, 2020

Re: Request for Integrated Transmission Plan

To: Mr. Aubrey Johnson
Cc. Jennifer Curran, Clair Moeller, Jeff Webb, Brian Tulloh, Derek Mosolf, Darrin Lahr

Attachment: CapX2050 Transmission Vision Report Executive Summary

The CapX2020 participating utilities respectfully request that the Midcontinent Independent System Operator (MISO) initiate a comprehensive, long-term transmission planning analysis using an integrated approach to identify a plan to optimally meet the year 2030 goals of utilities, their customers, and policymakers in the Upper Midwest. The power supply in the Upper Midwest is amid an unprecedented evolution with over 50% of the existing dispatchable generation fleet likely to retire in the next decade with plans for it to largely be replaced with wind and solar generation resources.

The recently published *CapX2050 Transmission Vision Report* highlights the increased criticality of a robust power grid and the need for additional regional transmission infrastructure to enable the generation fleet transition in a reliable, affordable, and safe manner. Our recent evaluation yielded conclusions that are consistent with many of the findings in MISO's Renewable Integration Impact Assessment (RIIA) which demonstrates the potential need for transmission system enhancements as renewable penetration levels exceed 30% of energy MISO-wide penetration levels consistent with current Integrated Resource Plans of the aggregate MISO region utilities. Given these expectations, the pace of fleet evolution we continue to experience, and the time needed to adequately plan, permit, and construct transmission upgrades, it is critical to identity the necessary enhancements beginning in MTEP21. We urge MISO to immediately initiate the requested planning analysis and to focus on expeditiously identifying solutions in the near term which are not only "least regrets" but also "scalable" to fit with longer-term plans of the future grid. We believe that such analyses are consistent with the ongoing development of the planning Futures and identification of transmission system inefficiencies based upon the range of potential outcomes depicted in those Futures. We also recognize that MISO is currently engaged in several Targeted Studies across the MISO region including the North Region Economic Transfer Study, Michigan Import/Export Assessment, and North/South Capacity Expansion Study. We urge MISO to continue with these efforts and to expand the scope of these studies as necessary to address expected grid needs. This approach of addressing needs on a MISO subregional basis, underpinned by the Futures, can identify regional needs while respecting subregional differences in the grid and in energy policy goals.

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The CapX2020 participating utilities have performed extensive analyses to identify the need for a comprehensive long-term transmission plan.

In 2004, CapX2020 came together to create a joint vision of the required transmission infrastructure needed to meet the projected growth of electricity requirements in the Upper Midwest and to create an environment to develop this infrastructure in a timely and efficient manner. As owners of the transmission system, we are obligated to plan and implement transmission upgrades which provide Upper Midwest consumers – and all users of the regional transmission grid – with safe, reliable, and affordable energy. The CapX2020 transmission development in the last decade involved over 800 miles of high voltage transmission and was successful in not only meeting goals to get us to our target year of 2020 but have also inspired us to not only extend our vision, but to take further necessary action.

In an effort to extend our vision into the next set of actionable steps, we published the *CapX2050 Transmission Vision Report* in March, which outlines four key takeaways that must be considered when designing the future power grid in order to ensure that the future system remains safe, reliable and affordable while allowing for an unprecedented level of change - characterized by significant reliance on non-dispatchable resources. Those key takeaways are:

- Dispatchable resources support the electric grid in ways that non-dispatchable resources presently cannot and therefore, some dispatchable resources will be necessary.
- The ability for system operators to meet real-time operational demands will be more challenging and therefore, we will need to develop new tools and operating procedures to address the challenges.
- More transmission system infrastructure will be needed in the upper Midwest to accommodate the transition of resources.
- Non-dispatchable resources alone will be incapable of meeting all consumer energy requirements at all times, and therefore, we will need to understand and promote a future electric grid that can continue to meet consumer energy requirements safely, reliably and affordably.

As we consider the next steps beyond our *CapX2050 Transmission Vision Report*, we envision a need for a comprehensive planning approach, that incorporates these four key takeaways. We also recognize the impacts to the regional grid operated and planned through our collective participation in MISO and realize that transmission planning cannot occur in isolation.

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We respectfully request MISO initiate a comprehensive transmission planning study for the MISO "Classic" subregion as outlined in the goals listed below for 2030. As MISO moves forward with the necessary grid planning, we also request that this analysis be informed by and used to inform discussions of meeting longer-range goals through the incorporation of new technologies, utilization of highly efficient long-distance transmission, and redefined policies to incent providing attributes foundational to the continued delivery of safe, reliable and affordable electric energy.

Goal 1: Strengthening the existing transmission system, but still allowing flexibility to meet future needs such as by:

- Increasing utilization of more efficient resources to meet goals in line with the varied preferences of individual companies and taking advantage of the most cost-effective resource locations.
- Increasing system strength, operability and reliability for a wider range of future scenarios.
- Increasing effectiveness of existing ancillary service capabilities and allowing for the adoption of new technologies to meet system needs.
- Increasing optionality for future system changes.

Goal 2: Taking advantage of a stronger transmission system to create a more tightly interconnected grid, allowing for more effective use of energy and ancillary services when and where they are needed by:

- Identifying interchange points for long-distance transfers.
- Utilizing long distance connections to allow access to the lowest cost resource locations
- Capturing geographic and weather diversity over a wider region to efficiently enable higher penetration levels of intermittent resources.
- Incorporating technologies to address local issues raised by resource changes while also enabling regional coordination.

To meet these goals, we request an integrated approach which simultaneously employs multiple tools and processes including, but not limited to:

- Long-term system reliability (steady-state thermal and voltage analysis)
- System stability in a reduced inertia system
- Operational complexity (analysis of non-transmission alternatives and/or solutions to operability in a mainly power-electronics based system)
- Market economics (analysis of market efficiency and system flexibility)
- Energy adequacy to serve customers over all hours of the year (ensuring adequate import/export capability into various regions)

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- Leverage stakeholders' detailed knowledge of their systems

In addition to the technical analyses performed, policies (including cost allocation), procedures, and market mechanisms will need to be created or existing practices updated to incent or support what is needed for a safe, reliable and affordable system in the future. A parallel effort to the technical analyses will need to take place to address and develop policy level solutions as issues are identified.

We applaud MISO's forward thinking as demonstrated in the Renewable Integration Impact Assessment, MTEP21 Future Scenario development, current Targeted Studies, and Resource Availability & Need effort as necessary to enable a power grid that is flexible to accommodate whatever the future may hold. It's our hope that this request serves to stitch together all these efforts to determine an actionable near-term transmission plan. We appreciate MISO's consideration of this request and are committed to working with MISO and its stakeholders, and utilizing our knowledge of our systems, to bring a future transmission plan to fruition.

Central Minnesota Municipal Power Agency

By:
Name: Christopher Kopel
Title: CEO

Otter Tail Power Company

JoAnn M Thompson
Vice President, Asset Management

Ben Porath

Ben Porath
Chief Operating Officer
Dairyland Power Cooperative

Rochester Public Utilities

Sidney Jackson
Director of Core Services

Great River Energy

Priti Patel
Vice President & Chief Transmission Officer

Southern Minnesota Municipal Power Agency

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Director of Operations and Chief Operating Officer

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Minnesota Power

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SVP Transmission

About CapX2020:
CapX2020 is one of the largest transmission-development initiatives in the nation. Our duty is to reliably and affordably serve our consumer's current and future power supply needs. The ten utilities include cooperatives, municipals, and investor-owned utilities providing reliable transmission service to nearly 5.5 million electric consumers for decades. Collectively, we operate over 42,000 miles of transmission lines in our combined service territories and are national leaders in planning, building, and maintaining a reliable transmission system capable of using the most cost-effective resources available.

The utilities include:

- Central Minnesota Municipal Power Agency
- Dairyland Power Cooperative
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- Rochester Public Utilities
- Southern Minnesota Municipal Power Agency
- WPPI Energy
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CapX2050

Transmission Vision Report

March 2020

CapX2020

EXECUTIVE SUMMARY

The goal of this CapX2050 Transmission Vision Report is to educate and inform Upper Midwest policymakers and other stakeholders of the implications of a future that is more reliant on non-dispatchable resources. It is not intended to forecast the transmission system in 2050. The challenges identified in this report promote understanding, helping stakeholders identify and implement solutions that enable the generation fleet to transition to a reduced-carbon future. As transmission owners and operators of the transmission system in the Upper Midwest, we are focused on the impacts to transmission system operations and ensuring that grid reliability continues to be met as generation resources transition to non-dispatchable resources. We must also consider the rate and timing of these transitions; particularly the level of non-dispatchable resources in the resource mix. Specifically, the report addresses these top four critical findings that are necessary to continue operating a safe, reliable, and affordable grid:

- Dispatchable resources support the electric grid in ways that non-dispatchable resources presently cannot and therefore, some dispatchable resources will be necessary.
- The ability for system operators to meet real-time operational demands will be more challenging and therefore, we will need to develop new tools and operating procedures to address the challenges.
- More transmission system infrastructure will be needed in the upper Midwest to accommodate the transition of resources.
- Non-dispatchable resources alone will be incapable of meeting all consumer energy requirements at all times and therefore, we will need to understand and promote a future electric grid that can continue to meet consumer energy requirements safely, reliably and affordably.

The CapX2020 utilities are committed and confident in finding viable solutions through future collaboration.

Overview

CapX2020 is a broad mix of 10 investor-owned and not-for-profit cooperative and municipal utilities working together to reliably serve their customers, consumers, members. We all serve load in the Upper Midwest and own and operate transmission infrastructure throughout our respective service territories. We have a unique long-term, collaborative working relationship. We know our system and we know our customers. Read more about **Who We Are**.

Our collaboration allows us to develop needed transmission expansion that benefits our communities and consumers. The CapX2020 collaboration successfully planned and built approximately 800 miles of high voltage transmission lines and 22 substations from 2004 – 2017 to benefit the region. This buildout created a backbone of transmission that improved reliability and enabled more renewable generation to connect into the electric grid (approximately 3,600 megawatts so far).

The CapX2020 utilities are committed to provide continued reliable supply of energy under all conditions to meet customer demand every hour of the year. We are committed to working together with policymakers and other stakeholders to ensure a reliable transmission system that keeps electricity affordable as new, non-dispatchable resources are added and dispatchable resources are retired.

Key Terms

Electric Grid

All components of the overall infrastructure that contribute to powering consumers' lives including the generation, transmission, and distribution systems. A reliable and affordable electric grid is a cornerstone of a strong and healthy economy.

Transmission System

The poles, wires, substations, and associated equipment that provides a reliable connection between generation and distribution. The transmission system should be developed to maintain reliability while supporting different generation resources ('non-denominational'). While the transmission system itself will not affect the change necessary to meet carbon reduction efforts, it is a key enabler of integrating more non-dispatchable energy resources.

Dispatchable Resources

Generation resources that may be called upon with short notice to meet immediate customer needs. Utility operators depend on these resources' ability to ramp up or ramp down their energy output as needed by the system. Dispatchable resources include resources such as coal, natural gas, hydro-electric, and nuclear facilities. Future dispatchable resources may include various new technologies.

Non-dispatchable Resources

Intermittently operating resources whose output cannot generally be controlled when operating. In particular this refers to wind and solar facilities without energy storage. Due to its variability, real-time operators cannot depend on the desired amount of energy at a specific time.

Ancillary Services

For the purposes of this report, grid attributes outside of the production and delivery of real power such as frequency control, inertial energy, voltage regulation, and short circuit current are collectively referred to as 'ancillary services.' They are the collection of attributes that support a reliable grid by helping maintain system strength, stability, and reliability.

Our Approach

CapX2020 announced a plan in August 2019 to study how a concerted effort to reduce carbon emissions from the generation of electricity could affect the transmission system that serves Minnesota, eastern South Dakota and North Dakota, western Wisconsin and the surrounding areas (the "CapX2020 footprint"). The goal of this CapX2050 Transmission Vision Report is to provide stakeholders a basic understanding of the potential operational and planning issues that need to be considered and addressed in order to facilitate the transition from the traditional fleet of dispatchable resources (coal, natural gas, and nuclear) to a more non-dispatchable, weather-dependent resource (wind and solar) fleet. A common understanding as to how the electric grid will operate in the future is important as we undergo this monumental transition.

This report is a critical step toward a common understanding of the issues and the eventual development of a comprehensive transmission plan to ensure the continued reliable performance of the regional transmission system. An emphasis on comprehensive, long-term planning will ensure a successful transition to a reduced-carbon future as the Upper Midwest generation fleet transitions to higher levels of non-dispatchable resources, distributed generation, and new energy storage technologies.

Finding #1

Dispatchable resources support the electric grid in ways that non-dispatchable resources presently cannot. They provide physical attributes that help maintain a stable and reliable grid. As dispatchable resources are retired, it will be essential that new and existing generation and transmission technologies are deployed with the ability to provide grid support in the appropriate locations to ensure reliability is maintained.

- The transmission system was designed in concert with dispatchable resources so that the required ancillary services are available where and when they are needed and are effective in maintaining system stability and reliability. When dispatchable resources are retired, appropriate amounts of grid support (e.g. ancillary services) will need to be provided at specific locations when and where it will be effective. In general, these ancillary services are less effective the farther they are from where they are needed unless sufficient transmission is in place. Read more about the **Fundamentals of Reliability**.

- Without dispatchable resources and the ancillary services they provide, technology advancements will be required to allow non-dispatchable resources to provide an adequate level of ancillary services to maintain a stable and reliable transmission system. Technological advances, in conjunction with new transmission technologies and/or storage resources, will be necessary to provide the required level of ancillary services when and where they are needed. Read more about **Technology Considerations**.
- The results of MISO's Renewable Integration Impact Assessment study (RIIA) are consistent with our findings. Changing the generation fleet from dispatchable resources to non-dispatchable resources will require innovative solutions (existing and new technologies) to maintain system stability and reliability. Read more about the **MISO RIIA Study**.

Finding #2

Reliably meeting real-time operational demands will become more challenging than they have been in the past as dispatchable resources are retired and their corresponding ancillary services are lost.

- Present technologies being used in today's non-dispatchable resources do not support a strong system in the same manner as dispatchable resources, resulting in a weaker transmission system.
- A weaker transmission system is more susceptible to unacceptable voltage fluctuations which can negatively affect consumers. Read more about **System Stability.**
- The power system protection technologies in use today may operate less predictably in a weaker transmission system. Read more about **System Strength**.
- The variability of the output of non-dispatchable resources, even within a single day, could lead to several thousands of MW being transferred across the transmission system, with reversals in direction of flow occurring in an equal, but opposite magnitude during the same day. Operating techniques, transmission infrastructure, and analysis tools will need to become more sophisticated to more accurately identify and adjust in real-time to deal with these changes. Read more about **Interface Flow Patterns**.

Finding #3

To maintain reliability of the system as we integrate more non-dispatchable resources and retire dispatchable resources, more transmission system infrastructure will be needed in the upper Midwest.

- A long-term comprehensive regional transmission plan with appropriate planning and cost allocation policies in place will promote a reliable and affordable electric grid for consumers throughout the region. Read more about **Transmission System Expansion Considerations** and **Energy Market Considerations**.
- Additional transmission infrastructure will:
  - Mitigate some of the negative impacts that retirement of dispatchable resources has on system stability and reliability;
  - Increase the options available for siting dispatchable and non-dispatchable resources in locations that are optimal for energy production;
  - Assure the reliability of the transmission system as distributed generation is added and more local microgrids are established;
  - Provide the necessary amount of capability to move energy between regions and ensure that energy needs are met for all hours of the year;
  - Promote a regional energy market which allows the most economic generation dispatch while maintaining reliability; and
  - Capture weather driven diversity from remotely-sited, non-dispatchable resources.

Finding #4

Non-dispatchable resources alone will be incapable of meeting all consumer energy requirements at all times. Dispatchable resources and/or energy storage with capacity for multi-day support will be needed.

- The increase of non-dispatchable resources combined with the retirement of dispatchable resources will put pressure on maintaining a sufficient supply of energy to match consumer demand at all times.
- Abrupt changes in weather, including prolonged extreme weather conditions, sudden changes in consumer demand, or disturbances on the transmission system (i.e., outages) will increasingly challenge the ability of the electric grid to provide a continuous supply of energy as more non-dispatchable resources are added. Read more about the **Variability of Non-Dispatchable Resources**.

- Adding more non-dispatchable resources alone will not mitigate insufficient energy supply. For example, under certain extreme weather conditions non-dispatchable resources would produce little additional energy when needed. At other times, these non-dispatchable resources would provide more energy than required to meet consumer needs and must be curtailed or exported.
- As non-dispatchable resources are added, sufficient dispatchable resources, which may include significant amounts of energy storage will be needed to maintain a reliable transmission system.
- Dispatchable resources and/or storage will be needed for periods when non-dispatchable resources are not sufficient to meet consumer demand. To be an effective dispatchable resource, storage would need enough capacity to provide energy for multiple consecutive days and/or during unusual weather conditions when there is not enough excess energy from non-dispatchable resources to re-charge the storage devices during that period. Read more about **Storage**.
- To complement the dispatchable and non-dispatchable resources, increased transmission system capacity will be needed to bring additional energy in and move surplus energy out of this region at different times of the year. When used to increase transfer capability, transmission expansion has been shown to be cost-effective when considered as part of a larger market. This is because it can act as a form of dispatchable resource to meet demand when local non-dispatchable resources are unavailable or producing in excess of local demand. Read more about **Transmission System Expansion Considerations**.

Looking Ahead

Understanding the critical issues outlined in this report will lay a foundation for more extensive studies in the future. We want to build on our history of listening and welcome the opportunity to provide information to policymakers and stakeholders as we plan the transmission system to support future objectives while addressing reliability concerns. We will use the feedback we receive to inform the technical issues that need to be addressed in one or more subsequent phases of this CapX2050 effort, and how to best integrate our efforts with those of MISO and others.

We don't have all the answers today but we will work on comprehensively studying a long-term transmission vision that will facilitate a greater reliance on non-dispatchable resources while ensuring reliable, safe, and affordable energy is provided to the consumers we serve. This remains a unified objective of the CapX2020 members. We will need to partner with our consumers, communities and stakeholders to embrace the changes of the future and address the challenges ahead of us, encourage innovation, and forge a path in the evolving energy future.

INTRODUCTION

Who We Are

CapX2020 is one of the largest transmission-development initiatives in the nation. Our duty is to reliably and affordably serve consumer's current and future power supply needs and growth. Our goal is to enable regional energy policies and provide safe, reliable, and affordable energy in the evolving electric industry.

The ten CapX2020 utilities include cooperatives, municipals, and investor-owned utilities providing reliable transmission service to nearly 5.5 million electric customers, consumers, and members ("consumers") for decades. Collectively, we operate over 42,000 miles of transmission lines in our combined service territories and are national leaders in planning, building, and maintaining a reliable transmission system capable of using the most cost-effective resources available. The CapX2020 utilities include:

- Central Municipal Power Agency/Services
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- Great River Energy
- Minnesota Power
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- Otter Tail Power Company
- Rochester Public Utilities
- Southern Minnesota Municipal Power Agency
- WPPI Energy
- Xcel Energy

Our ability, experience, and dedication to providing consumers with safe, reliable, and affordable energy allows us to plan and implement a future grid that can be flexible. It is our duty, as owners and operators of the transmission system, to enable consumers - and all users of our regional transmission grid – to achieve the energy choices they desire in the future.

The CapX2020 initiative began in 2004 with the intention of planning and constructing the transmission facilities necessary to maintain electric reliability and supply additional capacity for load growth while also providing transmission capacity for the development of non-dispatchable resources within the operating areas of the CapX2020 utilities. The initiative included the successful development of five major high voltage transmission projects: Big Stone South (SD) to Brookings County (SD); Brookings County (SD) to Hampton (MN); Fargo (ND) to St. Cloud (MN) to Monticello (MN); Bemidji (MN) to Grand Rapids (MN); and Hampton (MN) to Rochester (MN) to La Crosse (WI). This $2 billion expansion, consisting of approximately 800 miles of new 161kV, 230kV and 345kV transmission lines and 22 substations created a high-voltage transmission backbone necessary for a robust grid in the Upper Midwest. In total, the transmission lines enabled the interconnection of approximately 3,600 megawatts (MW) of wind generation which powers over 1.5 million homes and avoids 6.3 million tons of carbon dioxide (CO_2) per year. At present, approximately 50 new generation projects have requested to interconnect to these new transmission facilities. The CapX2020 projects are the largest development of new transmission in the area in over 40 years and have changed the energy landscape of the region.

Obligation to Serve

As transmission owners and operators, we are obligated to operate and maintain a safe, affordable, and reliable system within our bounds. In fact, our duty to serve is provided for in Minnesota Statute 216B.04 which states: "Every public utility shall furnish safe, adequate, efficient, and reasonable service…" Additionally, Statute 216B.029 states that "The commission and each cooperative electric association and municipal utility shall adopt standards for safety, reliability, and service quality for distribution utilities. Standards for cooperative electric associations and municipal utilities should be as consistent as possible with the commission standards."

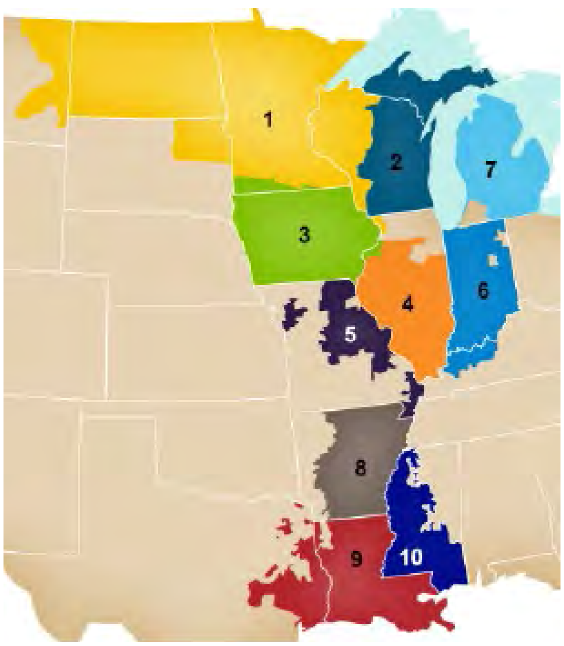
NERC, formed in 1968, is a non-profit entity that oversees six Regional Entities. NERC's primary responsibility is to develop power system standards, monitor and enforce those standards, and ensure power system operators are qualified through training. The CapX2020 utilities are a part of the Midwest Reliability Organization (MRO), one of the six Regional Entities overseen by NERC. The MRO provides "clarity on industry expectations and regulatory requirements; assurance of reliable operations across the connected power grid; and results that improve the reliability of the bulk power system".

Additionally, the CapX2020 utilities are transmission-owning members of the Midcontinent Independent System Operator (MISO). MISO is an independent, non-profit Regional Transmission Organization that delivers safe, cost-effective electric power across 15 U.S. states and the Canadian province of Manitoba. MISO provides non-discriminatory access to the transmission network under the guidance of FERC regulations, manages the movement of power across the grid through a wholesale energy market and performs regional transmission planning with stakeholders.

In addition to state regulations, utilities are also governed by federal entities such as the Federal Energy Regulatory Commission (FERC) and non-governmental organizations (NGOs) delegated by FERC such as the Midcontinent Independent System Operator (MISO), the North American Electric Reliability Corporation (NERC) and its regional delegate the Midwest Reliability Organization (MRO). The Institute of Electrical and Electronics Engineers (IEEE) is a leading NGO that encourages advancements of standards relating to new technology, providing guidance when it comes to reliably serving our consumers.

This report includes a discussion on some of the current regulations and guidelines including how they may need to adapt integrate more non-dispatchable resources. For the purposes of this report, we generally discuss grid operation including generation and transmission, consumer demand (load), and import/export relationships in the MISO Local Resource Zone 1 (LRZ 1). Figure 1 depicts LRZ 1 in yellow.

Figure 1. Local Resource Zones (LRZ)



Purpose of this Report

The goal of this CapX2050 Transmission Vision Report is to educate and inform Upper Midwest policymakers and other stakeholders of the implications of a future that is more reliant on non-dispatchable resources; it is not intended to forecast the future of the upper Midwest transmission system in 2050. The challenges identified in this report are intended to help stakeholders and policy makers better understand the impacts of the generation transition occurring. As owners and operators of the transmission system, we believe that it is important to understand these challenges. Specifically, the report addresses the critical elements that are necessary to continue operating a safe and reliable grid; describe how weather has, and will continue to influence how we plan and operate the transmission grid that includes more non-dispatchable resources; and identify what policies and procedures may need to change to successfully transition to a reduced-carbon future. It will provide foundational information upon which to identify transmission solutions and potential technology opportunities to integrate more non-dispatchable resources in the future.

This report does not provide definitive solutions to the issues that are expected to arise as the dispatchable resource fleet transitions to a non-dispatchable resource portfolio, nor does this report predict where modifications or additions to the transmission system should occur. Collectively, the CapX2020 utilities have the experts and industry experience and we envision this report to be the start of further study phases that will account for a future which is more reliant on non-dispatchable resources with the objective of maintaining a transmission system which offers reliability, safety and affordability.

Dispatchable Resources: Generation resources that may be called upon with short notice to meet immediate customer needs. Utility operators depend on these resources' ability to ramp up or ramp down their energy output as needed by the system. Dispatchable resources include resources such as coal, natural gas, hydro-electric, and nuclear facilities. Future dispatchable resources may include various new technologies.

Non-dispatchable Resources: Intermittently operating resources whose output cannot generally be controlled when operating. In particular this refers to wind and solar facilities without energy storage. Due to its variability, real-time operators cannot depend on the desired amount of energy at a specific time.

TRENDING: A REDUCED-CARBON FUTURE

The transition to a reduced-carbon future has woven its way into all aspects of our economy. In this section we discuss the state energy goals in the Upper Midwest and a few carbon-reduction goals of the companies who operate within our collective service territories. As transmission owners and operators, we are committed to providing a transmission system that supports different generation scenarios and ensures reliability.

In 2007, Minnesota Governor Tim Pawlenty signed the Next Generation Energy Act which requires the state to reduce its greenhouse gas emissions (GHG) by 80% between 2005 and 2050. The Act also supports clean energy, energy efficiency, and supplementing other renewable energy standards in Minnesota. Interim goals included a 15% reduction in GHG by 2015 and 30% reduction by 2025. According to the Minnesota Pollution Control Agency's (MPCA) January 2019 Greenhouse gas emissions in Minnesota: 1996-2016 biennial report, GHG emissions declined by 12% relative to 2005 levels, missing the 15% reduction by 2015 goal. It is important to note that emissions from electricity usage have been reduced by about 29% since 2005. The electricity generating sector has almost reached the 2025 emissions reduction goal. The MPCA report projects that as large, dispatchable resources are retired, electricity-based emissions will continue to decline.

In 2016, Minnesota advanced the 2025 Energy Action Plan, laying out a path forward for Minnesota to move toward a clean, reliable, resilient, and affordable energy system. The Energy Action Plan identifies strategies to capture opportunities that can strengthen Minnesota's clean energy leadership and help to meet the goals established by the Next Generation Energy Act.

Additionally, Minnesota Governor Tim Walz has stated that he will push for legislation and issued an executive order that would lead to 100% carbon free electricity by 2050, stating he wants utilities to be able to determine how and at what pace they achieve the goal.

In fall 2019, Wisconsin Governor Tony Evers issued Executive Order #38 that directs the new Office of Sustainability and Clean Energy to "achieve a goal of ensuring all electricity consumed within the State of Wisconsin is 100% carbon-free by 2050."

While North Dakota has not recently announced any additional goals around renewables, in 2007, North Dakota established a "Renewable and Recycled Energy Objective". That objective set a goal of 10% of all electricity sold at retail within the state by 2015 be obtained from renewable energy and recycled energy sources.

Similarly, while South Dakota has not recently announced any additional goals around renewables, in 2008 South Dakota established a "Renewable, Recycled and Conserved Energy Objective". That objective sets a goal of 10% of all electricity sold at retail within the state by 2015 be obtained from renewable energy and recycled energy sources.

Despite having less aggressive carbon reduction goals than Minnesota or Wisconsin, the impacts of the trend toward carbon-reduction in other Upper Midwest states may impact North and South Dakota. Both states have good resource availability for non-dispatchable resources, including wind and solar, while the interconnected nature of the transmission system means they, along with other states, will likely be impacted as the generation fleet transitions.

In addition to the Upper Midwest states advancing toward reduced-carbon generation resources, so have many Midwest companies. Companies within our service territories committed to a reduced-carbon future will rely on our reliable transmission system to achieve their goals. Here are just a few energy goals from companies in our region.

3M: Committed to reducing their GHG emissions by at least 50% below their 2002 baseline and increasing total renewable energy use to 25% percent by 2025. As of 2018, they've met or exceeded both goals. 3M's entire 409-acre headquarters is now powered 100% by renewable energy.

Ancillary Services:
For the purposes of this report, grid attributes outside of the production and delivery of real power such as frequency control, inertial energy, voltage regulation, and short circuit current are collectively referred to as 'ancillary services.' They are the collection of attributes that support a reliable grid by helping maintain system strength, stability, and reliability.

Cargill: Committed to reduce absolute GHG emissions in their operations by a minimum of 10% by 2025, against a 2017 baseline.

Ecolab: Goal to reduce GHG emissions by 50% by 2030 and to net-zero by 2050.

Organic Valley: Announced in August, 2019, that construction of three community solar projects totaling approximately 12 MW is complete, making the cooperative 100% powered by renewable resources.

The Minnesota Sustainable Growth Coalition: A business leadership group of nearly 30 organizations committed to sustainability, and recognizing that together they can have a larger, societal-level systemic impact on their operations, industries, environment, and community. Their collective vision is to surpass the State of Minnesota's current economy-wide GHG targets of 30% reduction by 2025 and 80% reduction by 2050.

GRID OPERATIONS

As previously stated, the operation of a safe and reliable transmission system is regulated by government agencies and non-governmental organizations. This report focuses on the transmission system because as transmission operators, planners, and owners we all have a responsibility to remain compliant with various standards enforced by the entities that regulate us.

In this section, we discuss the technical fundamentals that all transmission owners and operators must maintain to assure the reliable transmission of energy to consumers: system stability and system strength. Grid operations in a future more reliant on non-dispatchable resources will require more situational awareness and the ability to accurately identify and respond to disturbances.

Fundamentals of Reliability

The transmission grid was generally developed to move power from large, dispatchable resources (coal, nuclear, natural gas, and hydro-electric plants) to consumer demand areas, sometimes close in proximity, but oftentimes located far from the high-demand load centers they served. This configuration has operated successfully for decades by enabling reliable and affordable service to consumers. As increasing amounts of non-dispatchable resources have been added, changes have been made to transmission infrastructure and operations; however, many dispatchable resources are still operating and providing the necessary ancillary services, along with energy, to the grid.

When considering large-scale changes to generation resources (additions and retirements), we must do more than just replace the energy these resources provide but also determine how to provide the ancillary services that are essential to maintaining grid reliability and energy supply to consumers. Operating the grid is extremely complex and requires the management of numerous critical factors within defined limits, including but not limited to facility loadings, thermal and voltage ratings, voltage stability, frequency, and inertia, etc. For discussion purposes, we've focused our attention in this section on just a few critical components of reliability.

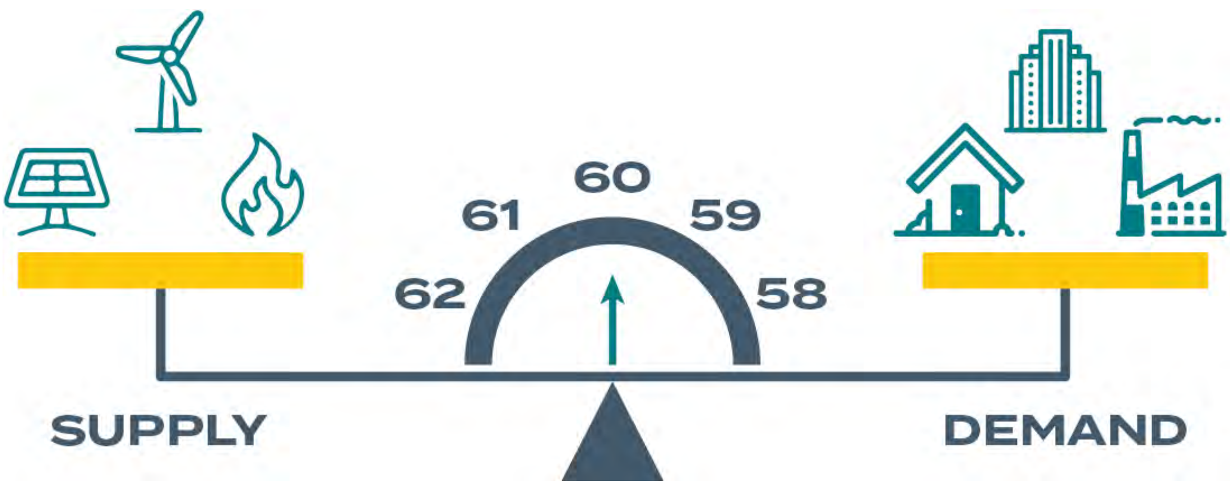
System Stability

In order to reliably serve consumers, it's critical that power system operators maintain system stability. In other words, it is our responsibility to ensure that our system responds predictably to disturbances on the system to minimize prolonged outages. A stable system operates normally under all reasonably expected conditions and is able to quickly return to a normal state if there is a disturbance to the system. Disturbances may include a transmission line or generator tripping off-line in response to a problem. First, we'll provide information on the key ancillary services attributed to system stability: frequency and inertia. Then we'll discuss disturbances on the grid and how responses to those disturbances are managed.

Frequency

In a stable U.S. power system, energy on the grid is constantly flowing at a rate of about 60 Hz (a frequency of 60 voltage cycle changes every second). This frequency is maintained by balancing how much energy is loaded onto the system and how much is used by consumers. If energy generation and consumer demand are generally equal, the frequency of the system remains stable at 60 Hz. If energy generation exceeds consumer demand, the frequency rises above 60 Hz. Conversely, if consumer demand exceeds generation, the frequency falls below 60 Hz. Consumer demand must equal energy production at all times to keep the system balanced. Without a balanced system, some end-use consumer equipment does not operate as intended when it is exposed to large frequency deviations from 60 Hz. Figure 2 depicts the relationship of energy supply and demand with system frequency.

Figure 2. Maintaining Frequency: Energy Supply and Demand



Inertia

Inertial energy helps maintain system stability. Dispatchable resources create energy by spinning massive rotating turbines and generators. When combined, the entire system's spinning turbines and generators provide inertia on the system which slow the effects of disturbances on the grid caused by outages to transmission lines or generators. If a disturbance were to occur, the system would initially respond to falling frequency by taking inertial energy from the remaining spinning turbines online. Then generators would respond to any sustained fluctuations by changing the amount of fuel delivered to the turbine, to increase or decrease the generator power production. Without sufficient inertia, this ramping action may be unable to return the system to a stable state (60 Hz).

Disturbance Event Response

NERC reliability documentation characterizes system stability as three distinct concepts: Pre-disturbance Equilibrium (how the system is currently balanced and operating), Disturbance Event (how disturbances, large or small, affect that balance), and Post-disturbance Equilibrium (how well the system regains balance after a disturbance). In the event of a disturbance to the system, there are several key variables that are monitored to ensure a reliable and predictable response occurs.

Rate of Change of Frequency

The Rate of Change of Frequency (RoCoF) is the rate at which the system is impacted by an event. It measures how fast the frequency decreases from 60 Hz.

Frequency Nadir

The nadir is the greatest point of system frequency departure from 60Hz. It is the point at which controls, including the generators, stop the drop in frequency, and after which the system starts to recover. In other words, the peak level of disturbance of an event.

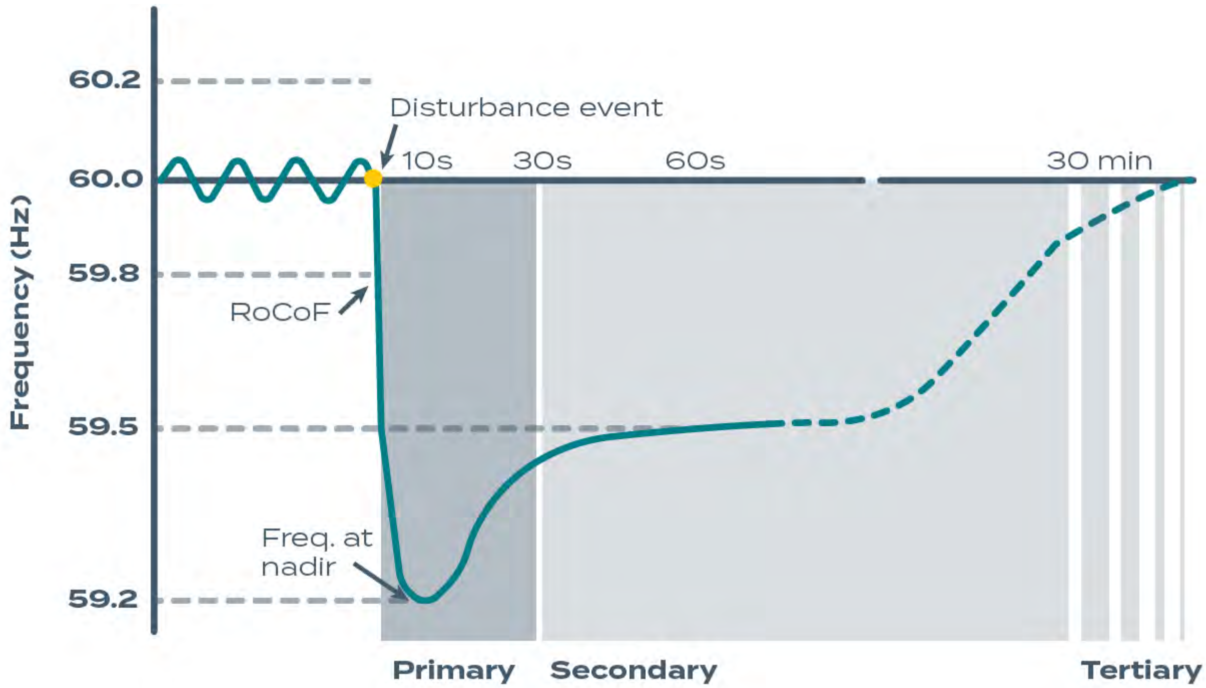
If the RoCoF is too steep, or the frequency nadir is outside the acceptable range for a given area, the system could involuntarily disconnect consumers or even suffer a catastrophic collapse and could result in that area becoming disconnected (islanded) from the rest of the electric grid.

Phases of Response

When a disturbance occurs, there are three phases of system response. The Primary response is generally a mechanical or electrical response that occurs very quickly – fractions of a second to a few seconds. Secondary response continues to restore system frequency to stable operating levels on a slightly longer time scale – seconds to minutes. Finally, Tertiary response (also known as reserve response) is intended to take the system back to normal operating conditions by economically rebalancing generation and demand.

Figure 3 depicts the RoCoF and frequency nadirs in a disturbance event and the subsequent phases of response thereafter.

Figure 3. Disturbance Response



This figure shows the grid operating at 60 Hz until an incident (yellow dot) creates a disturbance. In this example, the RoCoF is how quickly the frequency dropped and the nadir is the greatest drop in frequency experienced before the primary response mechanisms were able to stop the frequency drop.

Non-dispatchable resources, as presently operated, generally do not provide the same amount of inertia as dispatchable resources. Non-dispatchable resources are unable to maintain frequency by tapping the momentum stored in their turbines, nor can they adjust their fuel consumption (change wind speed or solar irradiance) in response to a system disturbance or changing load levels. Non-dispatchable resources may be able to provide stability support when operating if they contain advanced inverter technology.

KEY TAKEAWAYS ABOUT SYSTEM STABILITY

It’s imperative that we maintain grid stability by balancing energy production and consumer demand. The current mechanism to best maintain stability is the amount of inertial energy and response capabilities of the system.

As dispatchable resources are replaced with more non-dispatchable resources, it will be important to replace them with resources that can provide the same attributes and ancillary services that maintain system stability.

Non-dispatchable resources, while they have some attributes to help maintain system stability, do not have all of the necessary attributes to maintain system reliability. In addition, unlike most dispatchable resources, non-dispatchable resources are not available at all hours of every day. The current fleet of non-dispatchable resources provide ancillary services in different ways with different characteristics when they are operational, which may not always meet the system needs.

As we increase our reliance on non-dispatchable resources, we need to ensure that we have the right mix of ancillary services available at the right times and in the right locations to ensure that grid operations remain stable and to facilitate a real-time response in the event of a disturbance. These sources of ancillary services in the future may be provided by a combination of non-dispatchable resources, dispatchable resources (storage, synchronous condensers, natural gas, hydro-electric, load control, etc.), additional transmission system equipment such as static synchronous compensators (STATCOM), and technology not yet realized today. Future system strength and stability issues along with these potential mitigation alternatives will need to be explored and analyzed to identify the most effective method for maintaining a reliable grid.

System Strength

System strength is typically measured by the available fault current or by the Short Circuit Ratio (SCR). Available fault current refers to the amount of current flowing from generators to a short circuit on the transmission system. Automatic protection schemes and control systems need a certain minimum amount of current flow to reliably operate. The stronger a system is, the more quickly and reliably it can respond - and mitigate - disturbances. In weak systems, maintaining operational control and reliability in response to disturbances can become increasingly complex.

Fault Current

There are a number of different types of faults, but for this discussion, a fault or fault current is an abnormal electric current on the system due to a disturbance event.

Short Circuit Ratio

A short circuit is the resulting impact of a fault that results in the electrical current on the system exceeding the normal load. In protection and control systems, the difference between normal system condition and abnormal conditions is measured and used as a reference point to adequately protect the grid. The difference between normal and abnormal conditions is referred to as the SCR.

In today's system, areas with low SCR make it difficult for protection and control systems to differentiate between normal and abnormal conditions caused by a disturbance. Because of this, an abnormal condition may be allowed to propagate further than desired due to misidentification of a condition by the protection system. The reverse may also occur where protection and control systems may take action to mitigate a perceived abnormal condition when in reality the system was operating under a normal condition.

Today, most wind and solar facilities use inverters that are "grid-following" meaning they rely on a strong reference signal from the electric grid to operate in a reliable manner. Without a strong system providing a strong reference signal at the point of interconnection, the operation of these inverter-based generation resources may become less predictable, or in extreme cases, they may become inoperable all together. Alternatively, grid-forming inverters are an emerging technology that may operate without a strong reference signal and provide some of the ancillary services that existing dispatchable, non-inverter-based resources provide. The differences in grid-following and grid-forming inverters contribute to the reason why SCR as a measure of system strength isn't universally accepted.

Voltage Regulation

Voltage is the force that makes electricity move through the grid. Large changes to voltage levels can cause system instability and damage to electrical components, and even cause outages. A strong system can be measured by its ability to maintain voltage control in response to disturbances. Devices such as voltage regulators and capacitor banks are used to help maintain acceptable voltages on the transmission and distribution system within reasonable operating conditions.

Dispatchable resources add to system strength by acting as strong voltage sources ("reference signal") and are typically able to provide over 6 times their normal energy output during abnormal conditions. Their generator turbines spin at regulated or controlled speed so adjustments to the output voltage can be accomplished very quickly by changing the input voltage.

Non-dispatchable resources are largely inverter-based power sources that act as a constant voltage source and are typically only able to provide up to 1.5 times their normal load output in abnormal conditions.

KEY TAKEAWAYS ABOUT SYSTEM STRENGTH

As non-dispatchable resources replace dispatchable resources the overall system SCR (i.e. the difference between normal and abnormal conditions) is reduced, making it harder for transmission protection systems to determine the difference between normal and abnormal conditions. The reduction in the SCR must be replaced or new methods for system protection must be developed.

Protection systems using today's technologies can also become less predictable or more erroneous due to their reliance on a strong system signal. In a future that is more reliant on inverter-based, non-dispatchable resources that have little to no short circuit contribution, new technologies may be required to reliably respond and isolate abnormal conditions on the transmission system.

As more non-dispatchable resources are added to the electric grid and dispatchable resources are retired, system disturbances may become more severe if other suitable system enhancements or resources are not implemented. Presently, dispatchable resources help maintain system stability by being strong voltage sources; however, the ancillary services market may need to provide more incentive for non-dispatchable resource owners to choose equipment with grid-forming capability over less complex grid-following equipment.

CHALLENGES OF A CHANGING FLEET

As we transition away from a relatively small number of traditional dispatchable resources in our region and toward a large number of dispersed and relatively small, non-dispatchable resources in different locations across the Upper Midwest, we are challenged by the difference in ancillary services each type of generation provides. But we are also challenged by the way in which predictable and non-predictable weather events affect the energy output of non-dispatchable resources. To illustrate, this section provides several analyses of the ability for non-dispatchable resources to meet consumer demand during peak demand or extreme weather events. Following that, we provide an 8,760 hour-by-hour analysis of energy surplus and deficit, and lastly, an analysis on dispatchable resource needs in a zero-carbon future.

Variability of Non-Dispatchable Resources

Delivering energy becomes complicated by the fact that non-dispatchable resource output is heavily impacted by daily weather patterns and fronts as well as the daily and seasonal sun and cloud patterns. The variability of their energy output, in conjunction with consumer demand patterns, can result in periods of excess energy output while at other times providing insufficient energy output. Three distinct historical weather-related energy generation/consumption mismatch events, described below, illustrate the impacts that weather variability has on meeting consumer demand.

Historical Energy Production/Consumer Demand Mismatch Days

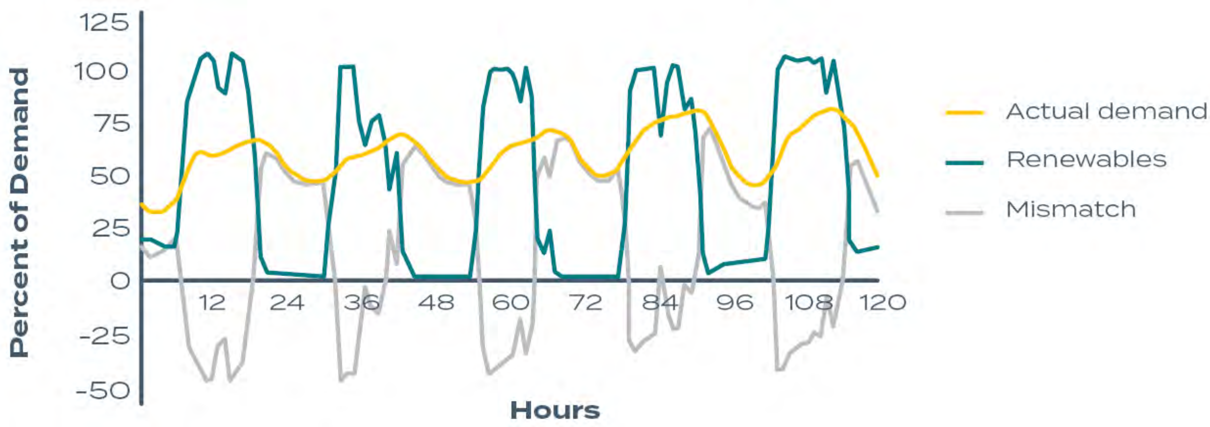
The review of historical market data illustrates the complexity of a sole reliance on non-dispatchable resources to deliver reliable energy that meets consumer demand in all hours of the year. Three historical events are recreated below in which it is assumed that there are no dispatchable resources to complement non-dispatchable resources. For each event non-dispatchable resource output and consumer demand are normalized, allowing the analysis of equal levels of nameplate wind, solar capacity and customer demand (i.e. for every 1 MW of peak demand there is 1 MW each of nameplate solar and nameplate wind). Actual consumer demand and renewable output values were then netted against each other to show the mismatch, or net demand in those hours. In each case, negative values for the mismatch (net demand) data indicates potential energy export to other areas outside of MISO LRZ 1 (refer to Figure 1) or generation curtailment scenarios. Curtailment is the reduction of non-dispatchable resource output below what it could have otherwise produced. Conversely, positive values for the mismatch data indicates the potential need for energy import from other areas outside of LRZ 1 or increased reliance on dispatchable resources.

July 28-31, 2018: System Peak with Negligible Wind Contribution

Wind and solar energy output can be predicted for typical weather patterns and is generally granted a level of accredited (expected) capacity based on its expected level of energy output during peak consumer demand periods. However, given the variability of non-dispatchable resources, it cannot be guaranteed that the expected amount of energy will be available to serve consumer demand during peak consumer demand periods. An example of this scenario occurred over a four-day period during July 28-31, 2018 over a wide area within the MISO footprint. During these potential peak demand days of summer, wind produced well below its expected levels for over 100 consecutive hours while high output from solar resource was ineffectual due to low penetration levels.

Normalized data is shown to better depict the mismatch in renewable output versus demand. In Figure 4, there are distinct hours where renewable output exceeded consumer demand (teal line exceeds yellow line) and areas where renewable output was significantly less than consumer demand (yellow line exceeds teal line). The mismatch that occurred when renewable output did not match or meet consumer demand is shown as the positive values of the gray line. Conversely, the mismatch that occurred when renewable output would have exceeded consumer demand is shown in the negative values of the gray line.

Figure 4. July 28-31, 2018 Normalized Market Data



During the hours that wind was production was negligible, solar output reached nearly 100%. When solar output exceeded consumer demand, energy export and/or generation curtailment would have likely occurred.

During the periods where solar output did not meet consumer demand (i.e. at night), mitigation measures such as ramping up of dispatchable resources and/or importing energy to 'fill the gaps' to meet consumer demand would likely have been employed.

January 8, 2019: Historic Wind Peak

There are times in which non-dispatchable resources produce energy at levels significantly higher than their accredited level. On January 8, 2019, MISO recorded a historical peak of wind energy being produced on the system. Normalized data is shown in Figure 5.

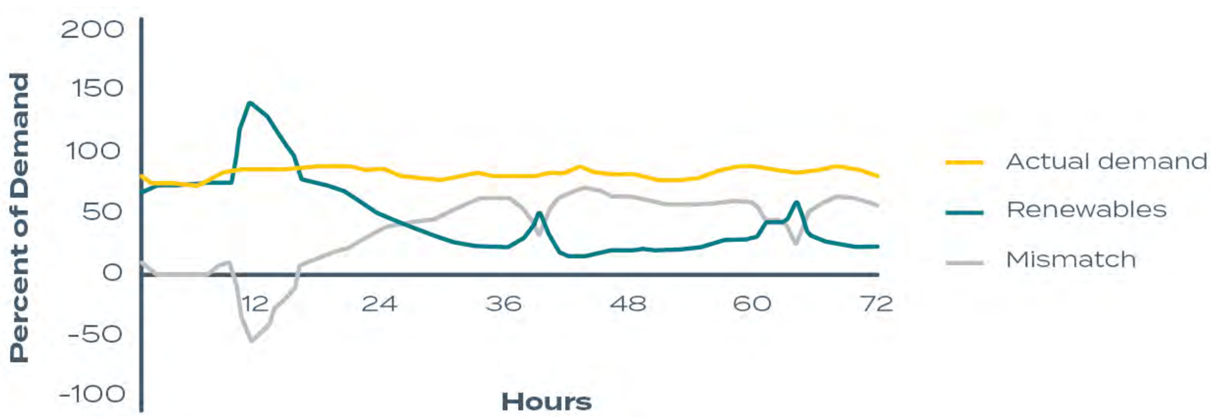
Figure 5. January 8, 2019 Normalized Data

As shown in the figure above, there would have been more renewable energy being produced than the total consumer demand (teal line exceeds the yellow line). In this event, the mismatch shows swings in energy imports (positive values of the gray line) and energy exports (negative values of the gray line), nearly exceeding 50% of consumer demand. Simulations show that the present import/export capabilities of the transmission system in this region are less than 40% of the peak consumer demand in this region and would have been exceeded during this event.

January 29-31, 2019: Polar Vortex

Non-dispatchable resources are significantly impacted by the environment in which they are operating. This extends to when those renewable resources are exposed to conditions outside of their designed operating limits. As shown in the data from the 2019 Polar Vortex, despite having relatively high wind speeds for much of the time depicted, the output from wind resources was significantly lower than expected due to the ambient temperature dropping below the minimum operating temperature of the wind turbine equipment. This also occurred at a time in which solar resources were unavailable (i.e. due to snow cover on many of the solar panels in this region and during nighttime hours). Normalized data is shown in Figure 6.

Figure 6. January 29-31, 2019 Normalized Data



This graph shows an extended period during which renewable output would not have met actual consumer demand (positive values of the gray line) without contribution from dispatchable resources.

The conclusions we can draw from these three mismatch examples is that non-dispatchable energy output does not always match up with consumer demand. As dispatchable resources are replaced by non-dispatchable resources, it will be important to find alternative resources than can be dispatchable and provide ancillary services and energy when and where it's needed.

Meeting Hourly Consumer Demand

Beyond the isolated examples of extreme specific, short-duration events detailed above, we performed an analysis to illustrate the extent that non-dispatchable resources could serve consumer demand in all hours of the year. We compared non-dispatchable resource production (based on MISO wind output and available hourly solar output) to hourly consumer demand data for a typical year. Figure 7 displays the energy surplus and deficit over the course of that year.

Figure 7. Forecasted Energy Surplus and Deficit

This exercise demonstrates that attempting to meet peak consumer demand of 20,000 MW with 40,000 MW of non-dispatchable resource capacity (i.e. for every 1 MW of peak demand there is 1 MW each of nameplate solar and nameplate wind) - and assuming perfect delivery of energy from renewable resource location to demand center - results in numerous instances throughout the year when consumer demand would not be met without some source of dispatchable resource (See several hours that have a deficiency). Through this evaluation, it was determined that there could be periods in which 85% of consumer demand would need to be met by a combination of actions or conditions, such as dispatchable energy resources, demand response and/or imports from other regions.

2050 Zero-Carbon Analysis

In addition to the historical analyses provided above, an analysis was conducted with production cost modeling software to determine whether there could be insufficient energy generation to meet consumer demand in 2050. Three scenarios were reviewed, each consisting of the lowest wind four-day period in the summer and winter, for a total of eight days per scenario. Similar to the historical analyses described above, this analysis highlights the challenge of meeting hourly consumer energy requirements with non-dispatchable resources exclusively, or near exclusively, when experiencing not-uncommon extreme weather events. Sensitivities that varied the assumptions for nuclear generation status and/or renewable resource type mix were not included in this analysis.

All scenarios were conducted for a hypothetical 2050 and assumed that all coal generation within the MISO LRZ1 footprint and neighboring local resource zones (LRZ 2 & 3) had been retired and replaced with non-dispatchable resources (wind and solar). The characteristics of the scenarios are described below:

Scenario 1 - Baseline: Baseline consumer demand and non-dispatchable output

Assumptions:

- Dispatchable natural gas simple- and combined-cycle resources are available
- 23.8 GW of wind and 15.8 GW of solar
- 90% of annual energy requirements are met with non-carbon emitting resources

Scenario 2 – Extreme Weather Event & Natural Gas Retired: Increased consumer demand by 15% above winter and summer peak

Assumptions:

- Natural gas retired
- 23.8 GW of wind and 15.8 GW of solar
- 100% carbon-free

Scenario 3 – More Non-Dispatchable Resources: Baseline consumer demand; non-dispatchable resources increase 10 GW (wind) and 10 GW (solar) above Scenarios 1 and 2

Assumptions:

- Natural gas retired
- 33.8 GW of wind and 25.8 GW of solar
- 100% carbon-free

Results

Simulation 1 results showed a heavy reliance on natural gas generation during both the four-day summer and four-day winter periods to meet consumer demand during low wind periods. In the extreme summer and winter weather events simulated in Scenario 2, all consumer demand could not be met in all hours of both four-day periods analyzed, demonstrating that replacing natural gas generation with large additions of non-dispatchable resources alone is not a viable solution to achieve energy balance in the most severe hours of the year. In Scenario 3, the addition of non-dispatchable resources beyond what was modeled in Scenario 2 failed to satisfy the consumer demand that was unable to be met in both four-day periods analyzed in Scenario 2.

The results showed there are many extended periods of time where the CapX2020 footprint is generation-deficient in a 100% carbon-free future. Adding more non-dispatchable resources in this area would not mitigate deficient energy periods because under these weather conditions, non-dispatchable resources would produce little additional energy. During generation-deficient time periods, there would be a need for dispatchable resources to generate for several days, meaning that using only short-term or daily cycling energy storage is not a viable solution. Storage would need to have high capacity and be available for multi-day durations.

KEY TAKEAWAYS OF THE VARIABILITY OF NON-DISPATCHABLE RESOURCES

The variable nature of non-dispatchable resources causes periods of time of insufficient energy output and times with excess energy output in relation to consumer demand. As dispatchable resources are replaced by non-dispatchable resources, it will be important to find alternative resources or technology enhancements that can be dispatchable and provide ancillary services and energy when and where it's needed. It may also require transmission expansion to facilitate the import/export capabilities of the region to address mismatched conditions.

The yearly study further demonstrates the effect of non-dispatchable resources on the grid by concluding that, when 40,000 MW of non-dispatchable resources is used to meet 20,000 MW of consumer demand, there will still be times in which 85% of consumer demand will need to be met by a dispatchable energy resource.

Lastly, the 2050 study, concluded that a reduced-carbon future needs dispatchable resources capable of generating for several days consecutively. This generation can come from existing technology, new technology advancements that enable long-term energy storage capability, neighboring areas via increased inter-area transmission capacity, or technology not yet realized today.

Heavy reliance on non-dispatchable resources to achieve a reduced-carbon future may result in the need for transmission expansion in combination with other grid solutions to allow energy to be imported and surplus energy to be exported during different times of the year. This expansion may be beyond the capacity of the existing transmission system necessary to get the non-dispatchable resources' energy to areas of consumer demand. However, the existence of increased interregional transmission capacity does not guarantee neighboring areas have energy available to export.

Increasing Non-Dispatchable Resources

MISO RIIA Study

Beginning in 2017, MISO embarked on a Renewable Integration Impact Assessment (RIIA) to analyze the regional impacts of increasing non-dispatchable resource penetrations across its footprint that extends beyond the CapX2020 utilities' combined footprint. The purpose of their study was to:

- Provide technically rigorous, concrete examples of integration issues related to non-dispatchable resources and examine potential solutions to mitigate them;
- Inform areas of focus and the sequencing of actions required as the addition of non-dispatchable resources increase; and
- Facilitate a broader conversation about non-dispatchable energy-driven impacts of fleet change on the reliability of the electric system.

This analysis was broken into several phases and is still currently underway. For the purposes of this report, we focus on the conclusions the MISO RIIA study made on the impacts of increased non-dispatchable resources on system strength and system stability.

System Stability Study

The MISO RIIA analysis also reviewed the impacts of non-dispatchable resources on system stability in the form of frequency response. Through this analysis, MISO found that retaining a stable and reliable system becomes more complex as the level of non-dispatchable resources increase. (Read more about **System Stability**).

In addition, MISO identified a more granular issue that shows the role today's dispatchable resources play in system stability. In this finding, MISO notes that with the reduction of large dispatchable resources (equipped with power system stabilizing equipment), small signal stability deteriorates on the region-wide system. Small signal stability is a core component of overall system stability and must be maintained to ensure a stable and reliable power system.

System Strength Study

As part of the MISO RIIA efforts, an analysis was performed to review system strength as non-dispatchable resource additions increased using the technologies of today. As shown below, when non-dispatchable resources are increased, the strength of the system deteriorates. (Read more about **Short Circuit Ratio** and **System Strength**).

Figure 8. Non-dispatchable Resource Additions and their Effects on System Strength

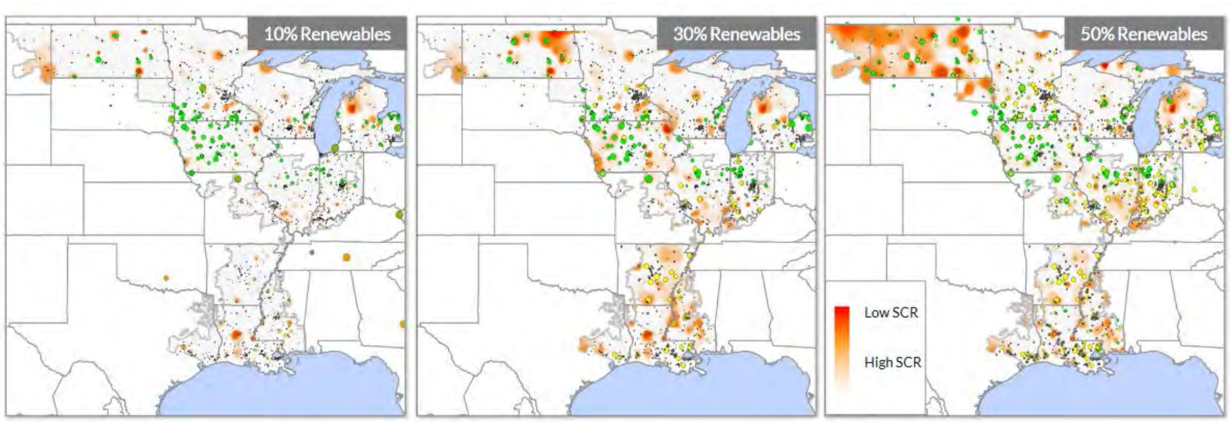


Figure 8 shows the progression of system strength deterioration (dark orange areas) as increasingly more non-dispatchable resources are added to the grid. Non-dispatchable resources provide little to no short circuit contribution, which is a functional measure of system strength. As discussed previously, this phenomenon increases the complexity of operating the system to reliably deliver energy to meet consumer demand.

KEY TAKEAWAYS FROM INCREASING NON-DISPATCHABLE RESOURCES

The MISO RIIA study indicates that several types of stability problems could occur when non-dispatchable resources comprise between 20% and 60% of all resources across the MISO footprint. The CapX2020 utilities operate in an area with the best wind resources relative to the rest of the MISO footprint. We expect our region to exceed the footprint-wide penetration level, meaning the CapX2020 utilities will be on the leading edge of finding and implementing solutions for expected stability challenges.

The results of the MISO RIIA study are also consistent with the CapX2020 utilities' findings that the transition from dispatchable resources to non-dispatchable resources will necessitate new and innovative solutions to maintain system stability and reliability.

Retiring Dispatchable Resources

Today's transmission system has evolved based on the understanding that large, dispatchable resources were available to respond to and mitigate the effect of (dampen) disturbances in the system. The existing dispatchable resources provide the necessary ancillary services to maintain system strength and provide immediate (i.e. less than 5 seconds) response during disturbances. Disturbances may include a transmission line or generator going off-line in response to a problem or undesirable fluctuations in voltage or frequency (read more about **Disturbance Event Response**).

The transmission system within this region has been developed over several decades with the objective of using the coal fleet to serve large consumer demand centers. Because of this historic coupling between generation and demand, ancillary services offered by the coal fleet were able to provide system stability. When these plants retire and are replaced with generation in different locations, the demand center may be served by generation resources located farther away. As both the geographic and electrical distance between generation resources and demand increases, the complexity of operating increases and the benefits of ancillary services provided by those resources is decreased. The resulting change has a negative impact to system stability that must be managed.

Before an owner is allowed to retire existing generation, MISO conducts an analysis of the retirement impact to the transmission system. If the analysis determines that the retirement of generation causes adverse reliability impacts, the generator owner will be required to keep the generator in-service until transmission projects or other solutions are placed into service to mitigate the impacts.

We discuss the implications of retiring dispatchable resources through the results of a large consumer demand center stability study and through a recent real-life example in northeastern Minnesota.

Large Consumer Demand Center Stability Study

A study was performed as part of a metro-focused study in conjunction with this report to determine the minimum amount of ancillary services required to maintain reliable service to a targeted large consumer demand center with major changes to the surrounding system.

Assumptions and Methodology

The analysis was performed using the 2018 MTEP dynamic model which represents light consumer demand and 90% wind output conditions in the year 2023. No load growth was assumed between 2023 and 2030 to limit the number of variables potentially affecting the results. Consistent with the industry trends, substantial additions of non-dispatchable resources were assumed to be added to the system. An addition of 5,800 MW of non-dispatchable resources dispatched at 4,440 MW was assumed to depict a higher reliance on non-dispatchable resources to replace the existing dispatchable resources. This study did not consider maintenance, forced outages, or economic factors into the ability of those services to be provided in all hours.

In order to determine system stability in this modeled environment, faults (i.e. disturbances) were simulated on the system to assess the ability of the grid to recover and return to a reliable state. (Read more about faults in **Disturbance Event Response**). This study was performed by 'turning off' dispatchable resources in a large metro area until stability issues were identified. To determine the level of stability services needed to maintain a stable system during severe conditions, previously retired dispatchable resources were 'turned back on' until the system was stable again.

Results and Conclusions

The results indicate that the system, as modeled today, cannot maintain stability without the assistance of a sufficient level of support that was, for this analysis, provided by dispatchable resources.

Furthermore, this stability study demonstrated that the system would remain stable when a fault occurs on a part of the transmission system where sufficient ancillary services are available from nearby dispatchable resource facilities. Whereas, a fault at a location farther from generation greatly increases the risk of system instability.

Finally, in these scenarios studied, an equivalent level of ancillary services as provided by the three natural gas generation facilities were all required to be operating at all times for the system to remain stable and sufficiently recover from disturbance events. This demonstrates the important role these services play in serving consumers with reliable electric service.

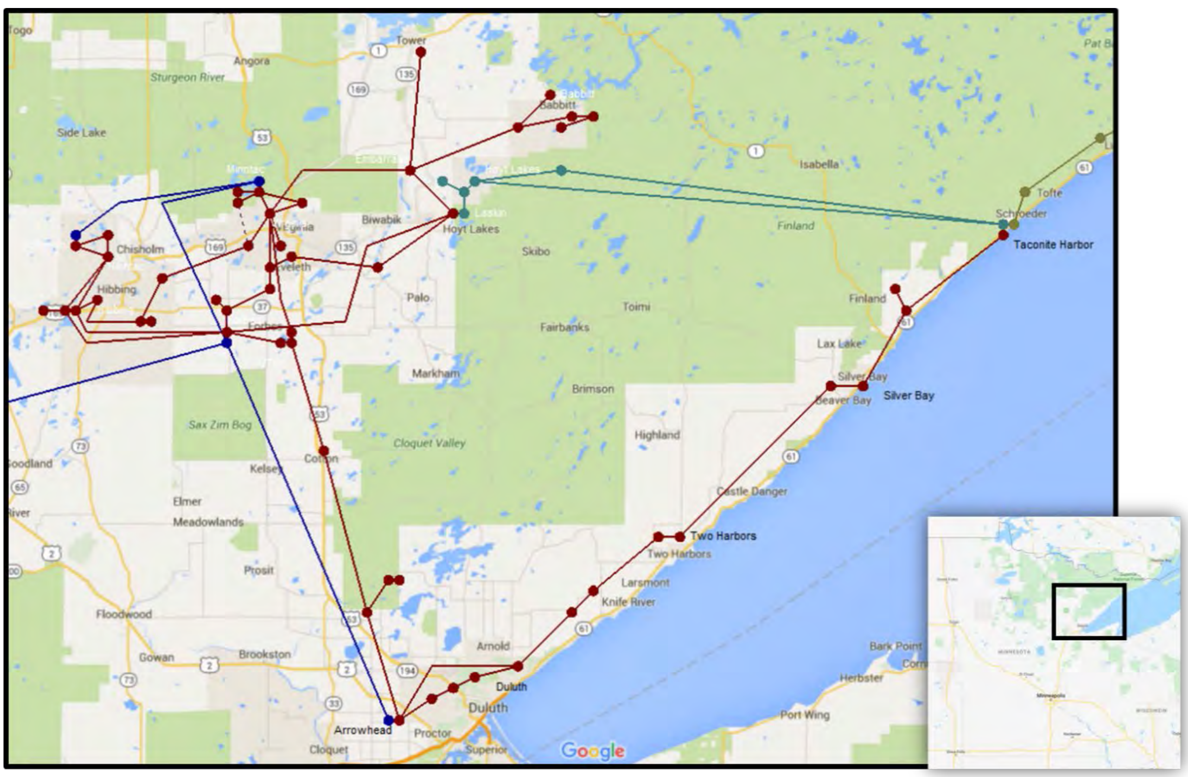
Minnesota Dispatchable Resource Retirement Example

The previous section details the expected system impacts resulting from retirement of dispatchable generating units in a large consumer demand center. Experience in our region has shown that even small-scale, dispatchable resource retirements cause transmission system impacts that must be mitigated and illustrates that transmission enhancements and/or expansion may be required in the future as dispatchable resources retire.

North Shore

The North Shore Loop (Figure 9) in northeastern Minnesota is a 140-mile system of 115kV (red lines), 138kV (green lines), and 230kV (blue lines) transmission lines and substations (dots) that are used by Minnesota Power and Great River Energy to serve consumers in a large area of northeastern Minnesota.

Figure 9. North Shore Loop Transmission System



Historically, the North Shore loop contained an abundance of dispatchable resources. Over a span of approximately five years beginning in 2015, all seven of the coal-fired generating units located at three sites have been idled, retired, or converted to limited dispatchable operation, operating only at times of peak consumer demand. The cumulative impact of these operational changes has effectively decarbonized the North Shore Loop, but leaves no dispatchable generators normally online to support the local grid.

Local dispatchable resources have contributed to the reliability of the North Shore Loop transmission system for decades by providing voltage support, power delivery capability, and redundancy, among other ancillary services. As a result of the rapid decarbonization of the North Shore Loop, several transmission projects throughout and adjacent to the North Shore Loop have been implemented since 2016 to maintain reliability. The most significant and complex of these transmission projects included a FACTS device (see **FACTS Devices**), specifically a static synchronous compensator (STATCOM) system in the Silver Bay area to support local voltage stability. Planning for this transition began in 2012 and project implementation is expected to continue through 2025 to fully address the reliability impacts of a fleet transition in the North Shore Loop.

KEY TAKEAWAYS FROM RETIRING DISPATCHABLE RESOURCES

The metro-focused stability study demonstrates that it is vital to perform a stability analysis and resolve any issues for each potential facility retirement so the analysis mirrors expected actual conditions at the time of retirement as closely as possible. The results of the stability study show that the technologies on the grid today cannot maintain system stability in a zero-carbon future without the assistance of a sufficient level of dispatchable resources or replacement of the ancillary services those resources provide. In the future, technology advances will be required so that non-dispatchable resources can provide the necessary capabilities when they are producing energy or, as an alternative, new technologies will need to provide the required ancillary services.

Additionally, the North Shore retirement example demonstrates that the replacement of dispatchable resources at their current locations and/or substantial transmission system development will be fundamentally essential to the reliable delivery of energy to serve consumer demand.

The results of the stability study for the large consumer demand center and experience within the North Shore Loop with small-scale dispatchable resource retirements support the ideas in this report; it is extremely important to consider the timing and location of dispatchable resource retirements, in addition to the type, timing, and location of incorporating new technologies into the electric grid. A discussion of new technologies begins in the next section.

STRATEGIES FOR CHANGE

The cost of non-dispatchable resources is decreasing; state and local jurisdictions have and continue to set decarbonization goals; and technological breakthroughs in energy technology and efficiency are on-going. The transition to a reduced-carbon future has woven its way into all aspects of our economy. While we can't predict what breakthroughs may occur as non-dispatchable resources increasingly replace dispatchable resources, we will consider operational strategies based on what we know today and projections made by key technology experts in the industry. We have a history of planning, developing, and delivering transmission solutions to address system challenges and intend to remain industry leaders in the future.

To recap, here are the major drivers of change that we've discussed in this report:

- States, utilities, and individual corporations are setting goals for a reduced- or zero-carbon future. As owners and operators of the transmission system, the CapX2020 utilities – in conjunction with the federal agencies and non-governmental organizations that govern and inform us – we will be key players in achieving the goals of our stakeholders;
- When studied, the results of a reduced- or zero-carbon future indicate that some amount of system stability (frequency and inertia) and system strength (SRC and voltage control) is required; however, the technologies on the grid today cannot maintain reliable system stability without the assistance of a sufficient level of dispatchable resources or replacement of the ancillary services those resources provide. Furthermore, the MISO RIIA study concluded that the addition of more non-dispatchable resources and the reduction of large dispatchable resources will result in the deterioration of system strength and system stability;
- Wind and solar energy output can generally be predicted during typical weather patterns. However, given the variability of weather and un-predictable extreme weather events, we cannot always guarantee the availability of that energy to serve consumer demand at all times. The 2050 zero-carbon study concluded that in modeled simulations, there is still a need to rely on dispatchable resources during minimal wind periods and adding more non-dispatchable resources alone is not a viable solution to achieve energy balance in the most severe hours of the year.

The strategies outlined in this section begin to address the issues listed above and provide additional cause-and-effect discussions on the predicted challenges of transitioning to a future more reliant on non-dispatchable resources.

Technology Considerations

Topics discussed in this section are a summary of a few technologies that may be employed to accommodate the predicted challenges associated with transitioning the grid to a future more reliant on non-dispatchable resources. Ongoing research and development, and subsequent commercialization in these and other technologies, may support breakthroughs that make new and different types of solutions viable.

Additionally, it will be the responsibility of transmission owners and operators, federal regulatory bodies (FERC), and non-governmental organizations (NERC, MRO, MISO, and IEEE) to work together to develop standards, guidelines, policies, and training to accommodate these developing technologies and alternatives.

FACTS Devices

Flexible Alternating Current Transmission Systems (FACTS) is a collection of power electronics-based devices used to adjust the power transfer capabilities of the system and/or improve stability or controllability of the system, particularly at critical conditions. Essentially, FACTS devices help make the most of existing resources' distributing power, reducing transmission system losses and improving the efficiency of the transmission system.

As we transition to a future more reliant on non-dispatchable resources, it will be important to closely follow FACTS developments. Their intended purpose of increasing the utilization of the existing transmission system by increasing capacity, make them attractive devices for maximizing transmission capacity for both present and future generation portfolios.

Advanced Inverter Technologies

Inverters convert wind and solar energy from Direct Current (DC) to Alternating Current (AC) power so that it can be fed into the transmission system. Advancements in inverter technologies have expanded upon the basic conversion function to provide additional benefits that include:

- Ability to control the amount of energy fed into or removed from the transmission system to maintain system stability by providing frequency and voltage regulation, and
- Communication with distributed generators (see **Distributed Energy Resources**) to provide backup during minor disturbance events.

Non-dispatchable resources in use today generally utilize inverters that most often require an external power supply in order to operate. They rely heavily on having a strong, consistent AC signal from the surrounding system to operate effectively. Most renewable generators today are referred to as 'grid-following'. If the external voltage is decreased as a result of a disturbance, the inverters turn off until a consistent AC signal is restored and thus the wind and solar resources they are connected to stop injecting energy into the transmission system. When this occurs, the load must be immediately served by another means (for example, dispatchable resources or imports from other areas).

A new technology to address this current-day issue is 'grid-forming' inverters. Unlike grid-following inverters, grid-forming inverters replicate the operations of dispatchable resources in helping to shape the AC signal of the system around them without reliance on a voltage established by an external source in the surrounding system. As inverter technologies become more heavily used, new breakthroughs of advanced inverters and dispatchable resources, and other transmission technologies will need to be developed to ensure a stable system with adequate system strength.

Distributed Energy Resources

Distributed Energy Resources (DER) are resources connected to the distribution system close to the consumer demand centers they're intended to support. DER can include wind, solar, micro-grids and energy storage (see next section).

DER is primarily a local energy resource with little to no visibility or control by the transmission system operator. DER often has capabilities for demand response or ancillary services for the transmission grid that go unutilized (or even work against system needs) because it is impractical for each individual DER to be a market participant. In the future, it is feasible to consider that entities, such as utilities, may act as an aggregator for DER in a local area and participate in the energy and ancillary services markets or a regional transmission organization, like MISO, as a virtual power plant.

In a growing DER landscape, the transmission system wouldn't be delivering energy from large, centralized generators all of the time, but may act as a network through which local areas could sell aggregated, excess energy produced via their DER systems. In essence, the role of the transmission system as being the connection point between sources of energy and concentrated areas of demand may remain largely the same, the difference being where and when those resources are producing and the areas and directions the power is transferred to meet consumer demand.

It should be noted that the increased use of DER challenges the current capabilities of the grid and challenges the existing operating paradigm. If the amount of DER surpasses the amount of local consumer demand at the same substation, power will flow onto the transmission system, resulting in present operational mechanisms and protections no longer operating safely and reliably.

As the use of the DER technologies grows, the wholesale energy market and operational paradigms will need to be redeveloped to accommodate these resources. The CapX2020 utilities will continue to research system protection systems and operational mechanisms that can adequately address an increase in DER.

Storage

As described in the **Historical Energy Production/Consumer Demand Mismatch Days** discussion, non-dispatchable resources will sometimes produce excess energy. This energy will need to be stored for later use, curtailed, and/or exported to other areas. In times of insufficient energy production, consumer demand will need to be served via dispatchable resources, or from stored energy, energy imported from other areas, and/or consumer demand will need to be reduced.

Storage devices include a broad range of different technologies such as batteries, flywheels, pumped hydro, power electronics (high-voltage, high-power, high-frequency materials), control systems (magnetics, capacitors), and software tools. Storage can be used to provide real-time energy to maintain a stable grid by releasing stored energy when non-dispatchable resources are insufficient and by storing energy during times of excess energy production from non-dispatchable resources. Storage can also provide some ancillary service contributions to the grid.

When there is sufficient capability on the transmission system to deliver energy from non-dispatchable resources to a storage device, it becomes a valuable energy resource to assist during periods of insufficient energy. It's important to adequately size a storage device so it delivers the quantity of energy for the length of time necessary to accommodate the short-term and long-term needs of the transmission system. However, the value of storage to the transmission system is limited if there is inadequate energy to recharge the devices.

OVERVIEW OF TECHNOLOGY CONSIDERATIONS

Technologies, like FACTS devices, advanced inverters, DER, and storage may all be viable solutions in maintaining system strength, stability, and energy sufficiency with the increased use of non-dispatchable resources. Improvements in today's technology, as well as new technologies that we can't even name today, are expected over the next several decades that will assist in the development of the future electric grid.

The National Renewable Energy Laboratory (NREL), a highly-regarded energy research-based organization provided considerations for policymakers as they consider a reduced-carbon future; some of them are summarized below:

- Should non-dispatchable resources be required to contribute to grid-stabilizing ancillary services (frequency and voltage regulation) - and how long/often should they provide these services and should they be compensated for such services?

- Consider updating policies and rules that allow for more flexibility in the existing reliability criteria.

To enable the use of these technologies, the CapX2020 utilities will continue to work with policymakers and stakeholders to ensure that the transmission system continues to be safe, reliable, and affordable. A key foundational concept for utilities, regulators and other policy-makers in subsequent planning phases of this CapX2050 effort is to consider the degree to which the **Local Resource Zones (LRZ)** area should or must be self-sufficient in energy supply in a reduced-carbon future, including under extreme weather conditions. This concept has implications for the amount and type of dispatchable and non-dispatchable resources that will be needed and the transmission capacity within the area and to external regions to allow for the import/export of energy during different times of the year.

Transmission System Expansion Considerations

The transmission considerations discussed in this section provide a brief description of present operating circumstances and outlines the changes needed to accommodate a transitioning generation resource fleet.

In this section we discuss: high voltage direct current transmissions alternatives; transmission expansion related to the transition of dispatchable resources to non-dispatchable resources, load growth and predicting consumer demand, how power flows through the grid within and between regions, transmission planning, predicting customer demand, and maintenance.

High Voltage Direct Current (HVDC) Transmission

The transmission system of today was built to provide access to the most economic resources available. While the type, size, and location of those resources may change over time, the role of the transmission system to allow access to the most economic resources remains the same.

In comparison to today's grid which primarily uses AC technology, HVDC transmission is appropriate for moving large amount of power long distances and other case-specific needs. With lower losses and greater power transfer capability compared to AC for the same corridor size HVDC transmission could be an appropriate mechanism for certain future generation development scenarios. Also, because HVDC lines connect to the existing transmission grid through the inverter technology, they have the ability to replicate certain ancillary services provided by localized generation. HVDC transmission technology has been used in LRZ 1 since the 1970's, but technology has and continues to advance, providing more capability and flexibility than in the past.

Retiring Dispatchable Resources

The retirement of dispatchable resources has resulted in transmission system investments to assist in replacing the energy and ancillary services they once provided. Historically, dispatchable resources were typically located near consumer demand areas or had strong transmission interconnections to them; however, without these dispatchable resources, those consumer demand areas could become deficient in being able to provide the required amount of energy or ancillary services to meet consumer demand and may require new transmission facilities to import energy or provide the necessary amount of ancillary services.

Load Growth and Predicting Consumer Demand

The need to build new transmission was historically driven by peak demand growth. Peak consumer demand growth over the last decade has been minimal due to a combination of utilities' energy efficiency programs and economic slowdown. Growth began to increase as the economy improved, but as utilities continue to encourage efficient energy use by their consumers, growth remains low. Electrification, including transportation and other industries could change that. Today, however, most transmission system expansion is being driven by the need to integrate and deliver increasing amounts of non-dispatchable resources and the retirement of dispatchable resources.

Non-dispatchable resources and consumer demand - which are uncorrelated and often mismatched - are often summed together and called 'Net Load'. The Net Load changes on a continual basis which has caused transmission system planners to examine each of the 8760 hours in a year, not just the traditional seasonal peak and off-peak periods.

Historically, the profile of consumer demand generally followed the daily activities of an area. In a highly residential area, there will typically be a rise in demand in the morning hours as people start their day followed by a small reduction in demand while those people head off to work. Once the typical workday is over, the system would see the highest demand of the day as people return home and start evening activities such as preparing a meal and cooling or heating their homes. As people end their day, the demand drops to the lowest levels overnight until the next morning starts the cycle over again. In comparison, an industrial area will likely have a much flatter demand curve, only increasing or decreasing as their processes ramp up and down. A commercial area may have a load profile that looks nearly opposite of residential demand with the highest demand levels occurring during normal working hours.

There are two major consumer-side incentives that can help stabilize consumer demand: time-of-use rates and demand management. Time-of-use rates are variations in energy costs to consumers depending on the cost to supply the energy and sometimes the impact to the transmission and/or distribution systems. Demand management modifies energy consumption at the consumer's location that would naturally occur and includes a wide variety of programs and types of implementation, including direct control of consumer loads by a utility.

In a future that successfully implements incentives that modify consumers' consumption behavior, the varying demand profiles of today could become significantly less variable and much flatter. A near constant level of consumer demand would require a unique approach to operational planning. For example, consumer demand and energy supply would need to be simultaneously balanced to ensure demand is being served while other services, such as energy storage, are being replenished for use at another time.

Forecasting future consumer demand growth becomes more challenging as consumers contemplate DER and micro-grids, in addition to continuous energy efficiency improvements occurring in appliances and building design. When consumers are using energy provided by DER and micro-grids, they're less reliant on the energy the transmission system provides at those times, making it appear that consumer demand is lower than its maximum demand. At other times DER might impose its full output on the transmission system or conversely inject energy into it, bringing new challenges for ensuring a robust and reliable electric grid.

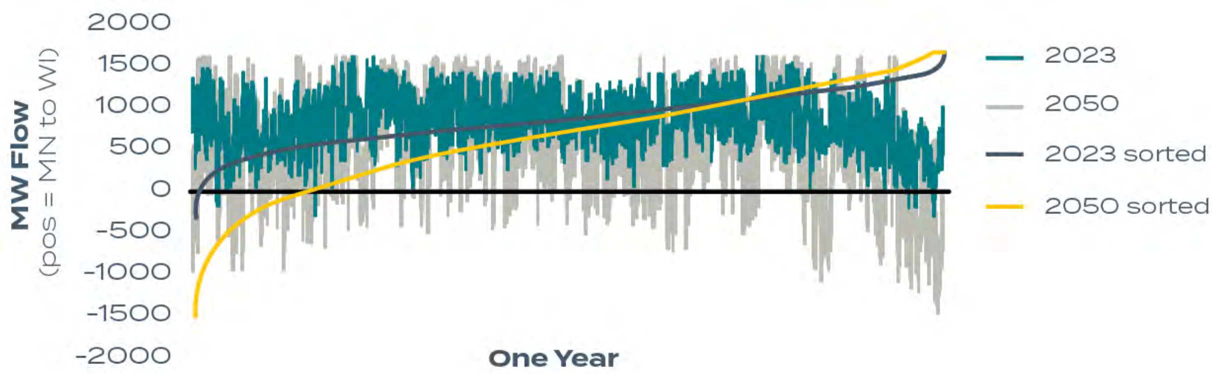
Interface Flow Patterns

Historically, energy between different regions of the transmission system, typically referred to as interfaces, flowed in one direction with minimal fluctuations. Three major interfaces exist within our region: North Dakota Export (NDEX), Manitoba Hydro Export (MHEX), and Minnesota-Wisconsin Export (MWEX). For the purposes of this report, we discuss one example, MWEX, to illustrate the challenges associated with energy flow between our region and neighboring regions – and how important it will be to accommodate changes in power flow in our operation of the future transmission system.

Example of Regional Interface Interactions

An analysis examining the annual power flows on the Minnesota-Wisconsin Export (MWEX) interface was performed to gain insight into operational differences between near-term conditions and a future with much more non-dispatchable resources. Figure 10 shows significant near-term, hour-by-hour variation between -500 MW to +1500 MW (green lines) in a near-term 2023 simulation. The 2050 simulation representing an even further fleet transition to include more non-dispatchable resources shows greater variability, widening to -1500 MW to +1600 MW (grey lines).

Figure 10. MWEX Interface Flow



In the 2050 scenario, electricity flows from Minnesota to Wisconsin during most of the year, but for 17% of the year the flow is in the opposite direction, from Wisconsin to Minnesota. This is unlike the near-term 2023 simulations where flow is from Minnesota to Wisconsin nearly 99.9% of the time.

As a result, it is expected that oscillating flow patterns, such as those across the MWEX interface, will occur more frequently and have higher magnitudes due to daily solar cycles, weather fronts, and increased geographic diversity of the non-dispatchable resources in the region. These changes could necessitate transmission system modifications to provide more capacity through certain interfaces and will certainly require more sophisticated operating techniques to deal with rapidly changing flow patterns.

Transmission Planning

Historically, transmission planning focused on several key distinct moments in the future; seasonal peak and off-peak periods and low consumer demand conditions. Each of these periods had well-defined base assumptions; the generation dispatch geography was well understood; consumer demand was based on projections developed from historical growth models; and power transfers were modeled based on transactions between entities. The idea was that if the system was deemed reliable during these key time periods then the system could be operated reliably during the rest of the hours of the year.

These historical assumptions were challenged as non-dispatchable resources were integrated into the transmission planning process. Early non-dispatchable resources had limited impact to transmission system planning due to their minimal size and share of the overall generation fleet. Due to the limited consumer demand growth, there were sufficient dispatchable resources available in the event that non-dispatchable resources did not generate. Additionally, because dispatchable resources typically have adequate fuel at all times, new non-dispatchable resources could be modeled based on their typical power output.

Increased reliance on non-dispatchable resources requires a more robust application of comprehensive, long-term planning processes that assure the transmission system is able to deliver adequate ancillary services to maintain system reliability at or above what is present today. The development of new transmission infrastructure is complex and can take seven to ten years to develop a single large-scale project. This development timeline could make it challenging to build the right projects within acceptable timelines. It is our obligation to provide a reliable transmission system so that a reliable supply of energy can be delivered to consumers during all hours of the year. Likewise, we must also develop the necessary transmission projects at the appropriate scale to avoid overbuilding, to retain flexibility to respond to unforeseen changes to the grid, and ensure affordability is balanced with reliability.

The existing rules and mechanisms that currently provide the robust, reliable, and cost-effective delivery of electric energy may need to be modified to better reflect the operational realities of increased non-dispatchable resources. Traditional transmission planning practices need to evolve in the future to encompass more operational scenarios that will become more challenging and more common with higher penetrations of non-dispatchable resources that are weather dependent. Likewise, separate study processes that exist today for interconnection planning, economic planning, operational planning and annual reliability assessments may need to be combined into a more comprehensive study to increase certainty that future transmission plans are able to provide multiple benefits. These changes to the traditional study processes will need to be implemented through necessary policy changes and must proceed expeditiously.

Future planning efforts will need to be integrated across generation, transmission, and distribution and will need to consider a combined approach that considers all three aspects of the electric grid through a single planning study. The CapX2020 utilities will continue to plan, coordinate, and collaborate with MISO and policymakers to ensure an appropriate and timely expansion of the transmission system in our region.

Maintenance

There has already been a major shift in the way transmission system facilities are de-energized for upgrades or maintenance. Historically, this work was completed during times of the year that were considered off-peak when the transmission system was not near its maximum capacity. Across the MISO footprint, this typically lends itself to a few months during the spring and fall.

As non-dispatchable resources increase, these typical maintenance or outage times are becoming less viable. High levels of energy transfers are now occurring during off-peak periods when consumer demand is lower and non-dispatchable resource output is high. Because of the decreased window of time to perform upgrades and maintenance, this necessary work either gets delayed, or performed on energized facilities which not only increases costs but greatly increases risk of injury or unexpected system events. In more localized areas, maintenance work could occur in the hottest summer months or the coldest winter months depending on the location.

In a future that is increasingly reliant on non-dispatchable resources, additional considerations of planned outages must occur to allow for the reliable and cost-effective delivery of energy.

KEY TAKEWAYS OF TRANSMISSION CONSIDERATIONS

Transmission considerations are pivotal as we transition to a future more reliant on non-dispatchable resources for electricity supply. Properly expanding grid infrastructure will:

- Mitigate some of the negative impacts that dispatchable resource retirements have on system stability and reliability;
- Increase the options available for siting dispatchable and non-dispatchable resources in locations that are optimal for energy production;
- Assure the reliability of the transmission system as distributed generation is added and more local microgrids are established;
- Provide the desired amount of capability to move energy between regions and ensure that energy needs are met for all hours of the year;
- Promote a regional energy market which allows the most economic generation dispatch while maintaining reliability; and
- Capture weather driven diversity from remotely-sited, non-dispatchable resources.

We must encourage policy changes to enhance existing planning processes to become more comprehensive to increase certainty that new transmission projects are offering multiple benefits.

In addition, we must consider the implications of consumer demand modeling and planned maintenance and outages as generation resources change and new technologies are incorporated into the transmission system.

Energy Market Considerations

The concepts discussed in this section describe current industry practices and standards related to resource adequacy and wholesale energy market interactions.

Resource Capacity Accreditation and Resource Adequacy

Resource capacity accreditation is the amount of power (MW) a specific generating resource is expected to contribute during the time period of the likely peak demand for electricity. The current process for determining a resource's capacity accreditation considers the historical performance of the resource over a three-month summer operation period which then determines the accreditation level for an entire operational year. To date, this has provided a high level of reliability by ensuring there will be enough generation capacity with sufficient actual energy output from the generation fleet to meet the highest demand period of the year.

The premise of the current resource adequacy process is assuring that load-serving entities have the necessary level of dispatchable resources to meet their resource adequacy requirement. Requirements are determined by regional analyses and in a few cases by local regulation. Requirements are usually based on assuring a 'less than one day in ten years' loss of load expectation or better.

The existing processes have proven to be successful as large dispatchable resources consistently produce energy output close to their accredited values whenever desired, but that framework may need to change going forward. The output of non-dispatchable resources vary greatly. As a result, accredited capacity based on probabilistic analysis of history will have little correlation to the actual amount of energy a resource will produce in a given hour. Additionally, reliability concerns have historically been based on seasonal peaks in summer and winter. As our studies have found, the increasing amounts of non-dispatchable resources, and the ability of those resources to serve consumer demand make it increasingly probable that reliability in the future will be a consideration for all hours of the year, not just critical peak or off-peak hours.

Physics dictate that energy consumption and supply be balanced every moment for the transmission system to operate at its desired frequency. The connection between energy balance and the resource adequacy requirement to transmission system planning and operation is that it is the responsibility of the grid operators, transmission-operating utilities, and MISO to assure the balance between supply and demand. The existing resource adequacy requirement that uses accredited capacity based on a probabilistic assessment of historical conditions and output levels will not provide reasonable assurance that there will be adequate energy to serve all load for each hour. In a future with considerable non-dispatchable resources, new rules and policies for resource adequacy and accreditation, if that concept continues to exist, will to need to change to assure that transmission operating utilities and MISO have enough energy during all times to maintain this critical balance.

Cost-Effective, Grid Congestion Mitigation

Today's wholesale energy markets are an intricate balance between system reliability and delivery of the lowest-cost energy available at any given time. With that balance comes the reality of transmission system limitations, which present themselves as congestion in market operations. Because a system with zero congestion (e.g. a copper sheet) would not be a cost-effective solution, the type, magnitude, and location of congestion becomes a vital consideration in accommodating a reduced-carbon future.

The transmission system of today has evolved around the availability of dispatchable resources and was designed to maximize the efficient and reliable use of those resources. This evolution has led to mostly consistent patterns in how electricity flows on the transmission system with historical areas of system congestion that are widely understood in their local and regional long-term planning processes. The facilities causing congestion change as upgrades are made to relieve congestion, but the flow patterns generally remain consistent and the next limiting facility is often predictable for system planners. In the MISO transmission planning process focused on identifying projects that lower the cost of delivered energy, one of the major considerations of a project's viability is whether the congestion that the project is mitigating has been shown to be present in real-time market operations. If the congestion has only been identified through modeling, but has not occurred in real-time operations, the congestion might be considered hypothetical and the project may not be approved due to its uncertainty of providing market benefits.

As we transition to a future more reliant on non-dispatchable resources, there will be a wider variety of flow patterns, depending on where it is windy or sunny and/or where the load is higher or lower. These flow patterns will be less predictable and less controllable, leading to more uncertainty in predicting where and how often congestion will occur. Historical congestion will not always represent the highest potential for cost-effective mitigations. Reliance on historic information of congestion patterns may actually hinder the development of mitigation that would enable the delivery of non-dispatchable resources in the most cost-effective way possible. Therefore, the processes currently used to identify and mitigate transmission congestion will need to evolve to better predict future congestion under a wider range of operating conditions.

Non-Dispatchable Resources Price Impact

In the existing wholesale energy market, the price that most non-dispatchable resources are offered into the market reflects a zero fuel cost. As more non-dispatchable resources are added to the system, there will be greater effects on the amount and output levels of dispatchable resources that are brought online. The energy market will need to accommodate this by providing appropriate price signals to all resources in the market to ensure sufficient levels of ancillary services are available at all times, as well as the desired amount of energy production.

Generation Costs

One of the major factors that led to the development of the current bulk power system in the U.S. was the realization of the benefits associated with economies of scale. The principle where cost savings are realized proportionally with increased levels of production led to large, centralized generation resources designed to serve large amounts of consumer demand. In today's industry, though somewhat skewed by variations in costs between large scale (or utility scale) and behind-the-meter consumer scale resources, that principle of realized savings through increased production still holds true. Lazard, an independent financial analysis firm, developed Levelized Cost of Energy charts (Figure 11 and Figure 12) for generation and storage technologies. These charts show, among other things, that the larger the scale of the individual facility, the lower the levelized cost. For example, a combined-cycle natural gas plant produces energy at $41-$74 per megawatt hour (MWh) vs. a residential rooftop solar panel array which produced $160-$367 per MWh.

Figure 11. Levelized Cost of Generation

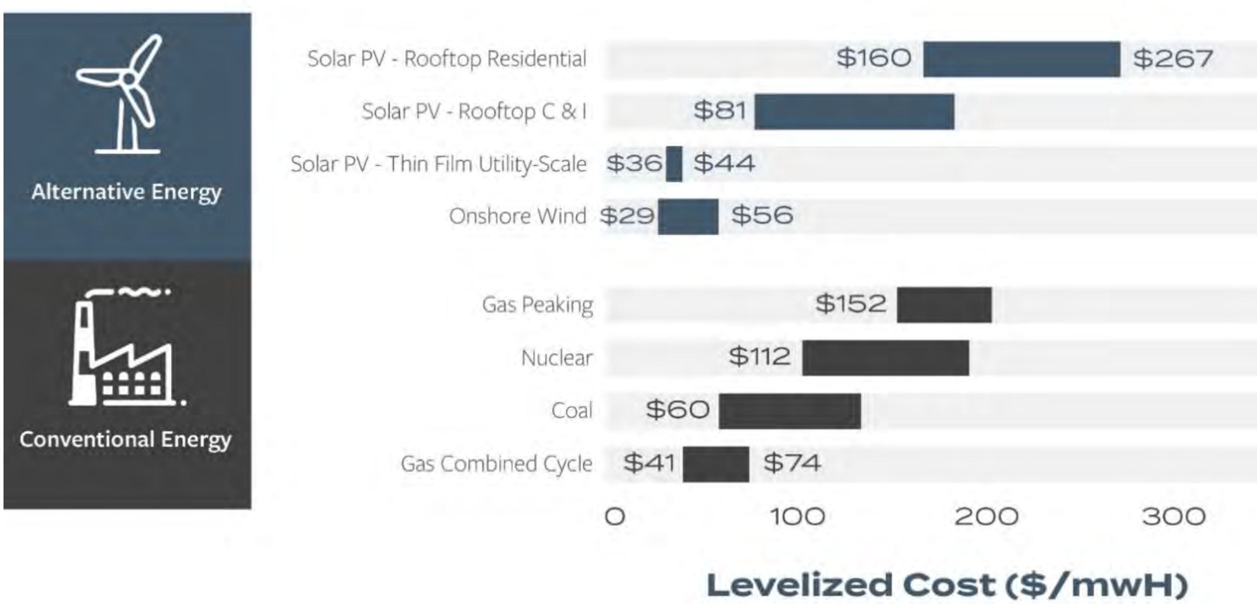
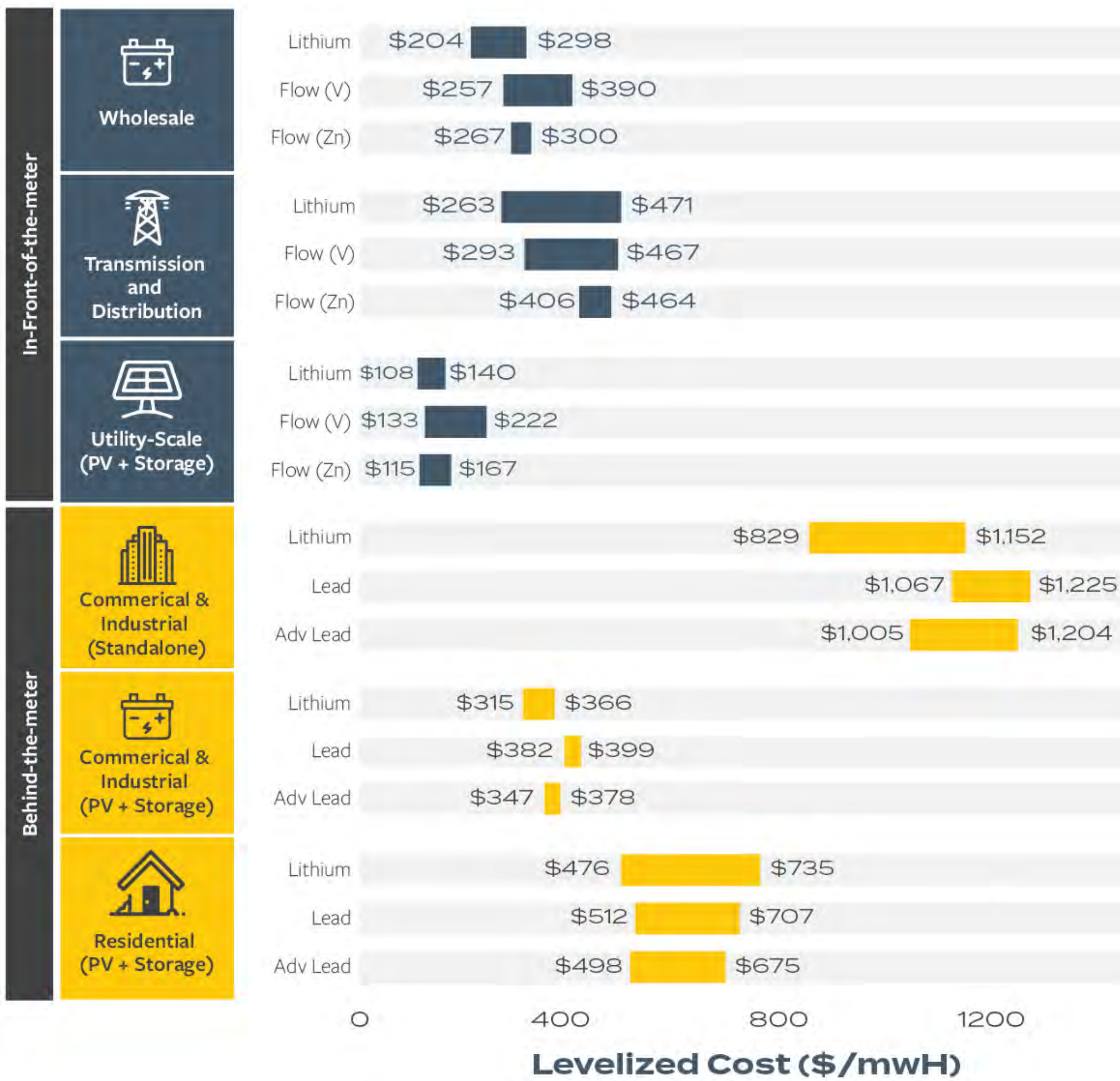


Figure 12. Levelized Cost of Storage



In a future more reliant on non-dispatchable resources, a more detailed examination of total "all in" costs - costs for modifications to the transmission and distribution systems, and costs to provide necessary ancillary services - will be required. These considerations will ensure the decisions about future resources represent the most cost-effective approach to achieving reduced-carbon future.

Distributed Generation Costs

A future more reliant on non-dispatchable resources is likely to include a heavier penetration of distributed generation. The existing mechanisms for assigning cost responsibility to distributed generation and compensating generators for benefits provided will need to be enhanced to provide appropriate incentives for how these units contribute to energy adequacy and grid reliability.

Transmission Cost Allocation and Recovery

New transmission projects (e.g., generation interconnection or reliability projects) are analyzed through separate planning processes based on the need for the project. Cost-allocation and cost-recovery is also based on this same planning process. If this current practice continues, it could result in too few or sub-optimal project proposals being approved. Transmission planning and cost allocation/cost-recovery need to be better aligned with each other to ensure that the right projects are being built at the right time, and paid for by the right beneficiaries.

LOOKING AHEAD

Understanding the critical issues outlined in this report will lay a foundation for more extensive studies in the future. We want to build on our history of listening and welcome the opportunity to provide information to policymakers and stakeholders as we plan the future grid to support future objectives while addressing reliability concerns. We will use the feedback we receive to identify the technical issues that need to be addressed in one or more subsequent phases of this CapX2050 effort, and how to best integrate our efforts with those of MISO and others. We will continue to comprehensively study a long-term transmission vision that will facilitate a reduced-carbon future while ensuring reliable, safe, and affordable energy is provided to the consumers we serve.

CENTER FOR ENERGY & ENVIRONMENT HOST COMMUNITY IMPACT STUDY SUMMARY

In our initial filing we provided a discussion of the ongoing Host Community Impact Study overseen by the Center for Energy and Environment (CEE). The Host Community Impact Study (Study) examines 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 (CUCs), Minnesota Power, and the Prairie Island Indian Community. The CUCs are a coalition of communities that host large baseload generation plants in Minnesota and include: Becker, Monticello, Red Wing, Oak Park Heights and Cohasset. With the support of the McKnight Foundation, the Just Transition Fund, and the Initiative Foundations of Minnesota, the CUCs contracted with CEE to oversee a study on the direct and indirect financial and social impacts of hosting a baseload power plant on the host communities.

The study consists of a quantitative and qualitative component. For the qualitative component, CEE partnered with the Coalition of Utility Cities, Xcel Energy, Minnesota Power, and representatives from each of the six communities to study the economic and social impacts that these power plants have on the communities that host them, as well as the potential effects of the plants' retirements. The final report, *Minnesota's Power Plant Communities: An Uncertain Future*, can be found on CEE's website at:

https://www.mncee.org/resources/resource-center/technical-reports/minnesota-s-power-plants-an-uncertain-future/

The quantitative component of the report consists of analysis conducted by the Business Research Division (BRD) of the Leeds School of Business at the University of Colorado Boulder. The BRD conducted economic modeling of the local and statewide impacts of the retirement of the baseload generation plants in Minnesota. The BRD analyzed local and statewide impacts of several based load retirement scenarios from our July 1, 2019 Resource Plan filing as well as the impacts of each plant in isolation. The analysis considers operating expenditures, capital expenditures, and consumer rate costs for each scenario relative to a reference scenario. The final report is also available on CEE's website at:

https://www.mncee.org/MNCEE/media/PDFs/Xcel-Energy-MN-Economic-Impact-Analysis-Final-Report-042820_2.pdf

We are grateful to CEE for overseeing this study and to the study participants for engaging in this constructive exercise. While the work took longer than anticipated, we believe the engagement of the participants in developing and refining the study resulted in a more valuable product. In addition to the studies available at the links above, CEE and community representatives conducted a well-attended webinar with stakeholders on May 20, 2020. The Commission also held a planning meeting on June 12, 2020 with several stakeholders including CEE, representatives for labor, the host communities and the Prairie Island Indian Community.

As we move forward with our carbon reduction goals, we are cognizant that phasing out some of our legacy generation 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. We are dedicated to working with our employees, communities, and stakeholders to manage community impacts throughout our clean energy transition. Our baseload generation plants are prominent places of employment and contributors to the property tax base in the host communities. 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 last Resource Plan, where we proposed to retire the Sherco 1 and 2 coal units in Becker, we have worked extensively with the local government, community stakeholders, and the state to draw new development to support the local economy. This includes a planned combined cycle generating unit at the Sherco site, the 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. In addition, we have proposed to add up to 460 MWs of solar at the Sherco site.[1] This proposed investment will provide significant economic stimulus and jobs for the local economy and the state of Minnesota.

In addition to the 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 re-locations, we have been able to successfully "re-home" nearly all impacted employees from plant closures and conversions to date.

[1] Docket No. E,G999/CI-20-492

Our plans for ensuring a just and equitable workforce transition are discussed further in Attachment C.

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. The Host Community Impact study provides further context and opportunities for engagement with our communities, employees, and stakeholders as we continue to work together on the clean energy transition.

Mixed Integer Programming (MIP) in EnCompass

EnCompass utilizes mixed integer programming to determine the optimal solution to capacity expansion, unit commitment, and economic dispatch problems.

Economic Dispatch

The economic dispatch problem seeks to minimize total production costs given a commitment schedule of which units are online and offline in every interval (usually one hour). EnCompass formulates this as a linear problem by using a piecewise-linear representation of unit heat and emission rates, and either a zonal or DC (linearized) powerflow model for transmission. Constraints applied for the economic dispatch include load and ancillary service requirements, transmission limits, fuel limits, environmental limits, storage limits and efficiencies, capacity factor (energy) limits, ramp rates, and resource capacity limits for energy and ancillary services.

Linear programming is a fast, robust, and well-established process that will always return an optimal solution if the problem is feasible (i.e., the constraints are not conflicting). EnCompass uses “soft” constraints for load balance, ancillary services, and certain transmission limits by allowing the limits to be violated subject to input penalties (unserved load and curtailment penalties). In this way, the problem will always be feasible, and any limit violations are reported. In most cases, there is only a single optimal solution. However, if there are multiple units with identical costs, the selection of which units to dispatch is arbitrary. EnCompass will always produce the exact same solution for the same scenario. If a unit that was not dispatched is removed from the scenario, the structure of the problem changes, and a different dispatch of identical units could occur if a different route were taken to find an optimal solution.

When EnCompass is run using the “No Commitment” option, the minimum capacities of resources that are not must-run are relaxed, so that there is no unit commitment problem to solve. In this mode, any startup and no-load costs are converted to linear $/MWh costs using the input Expected Runtime (or if not set, the Minimum Uptime), and are added to a unit’s energy and ancillary service costs. This option is the fastest way in which to run EnCompass.

Unit Commitment

The unit commitment problem extends the economic dispatch problem by allowing the selection of which units are online and offline in every interval, given a set of units with fixed commission and retirement dates. This selection uses integer, or whole-number, variables together with the continuous variables from the economic dispatch problem, which is why the methodology is referred to as a “mixed” integer program.

The unit commitment constraints that EnCompass applies includes minimum uptime, minimum downtime, maximum daily and weekly starts, and profiles for which intervals are allowed for unit starts and shutdowns. Fuel requirements and direct costs can be applied to starts and shutdowns, with the option to vary startup requirements based on cold, warm, and hot input definitions. Operating constraints can be applied across a group of units to model load pocket and voltage support requirements, as well as dependencies and other restrictions.

When EnCompass is run using the “Partial Commitment” option, all of the unit commitment costs and constraints are applied, but the number of units committed in any interval is allowed to be a continuous variable between 0 and 1. For example, if the optimal solution included a value of 0.3 for the number of units committed, this would incur 30% of the cost of a start and only allow the unit to dispatch up to 30% of its capacity. The unit would still have to be at least 30% committed for the minimum uptime, and once it goes below that cannot increase until the minimum downtime has passed. The Partial Commitment option turns the unit commitment problem into a linear problem, which makes it faster to solve than the “Full Commitment” option and provides more detail and constraints than the “No Commitment” option.

Capacity Expansion

The capacity expansion problem extends the unit commitment and economic dispatch problem by allowing the selection of new resources, transmission upgrades, and economic retirements. This selection uses also uses integer variables that represent the number of resource additions and retirements in each year. The economic carrying charge is used to represent capital costs for new projects, which increases at the rate of construction escalation and provides the same present value of annual revenue requirements over the book life.

Instead of firm reserve margin constraints, EnCompass uses capacity demand curves to incent meeting reserve margin targets. These can represent “high cliffs” where the penalty for falling short of the target reserve margin is very high ($10,000/kW-year) and then goes to 0 once the reserve margin is met; or they can be downward-sloping curves like those used in PJM, New York and New England for capacity markets.

Each project can have constraints on the maximum additions (incremental) per year, and the minimum and maximum active (cumulative) projects each year. Project Constraints can be used to set these constraints over a group of projects, which can include exclusivity and dependencies.

EnCompass includes a “Partial” optimization option which will allow the number of additions to be a continuous variable. For example, if the optimal solution included a value of 0.3 for the number of additions, this would incur 30% of the capital costs and only consider 30% of the capacity added. Over the operating life of the project, the number of active projects would be at least 30%. If the unit commitment option is “No Commitment” or “Partial Commitment” (which are the typical settings for capacity expansion), Partial project option turns the capacity expansion problem into a linear problem, which makes it faster to solve than the “Full” option. There is also a “Rounded” option which will automatically round up all additions and retirement to the next whole number, but this is typically only used for market-based capacity expansion over large regions. Finally, even with the “Full” option, individual projects can consider partial additions after an input year, which improves the overall runtime.

The MIP Process

If either the unit commitment or capacity expansion options are set to “Full”, EnCompass will solve the problem using mixed integer programming. Unlike linear programming, it is not always feasible to find the global optimal solution to a mixed integer problem since the process requires evaluating numerous potential integer solutions. Instead, the problem is considered to be solved when the costs of the best integer solution found is within an input tolerance of the cost of the best remaining partial solution (known as the best bound). The tolerance is measured as the percent difference between the best solution and best bound, and in EnCompass the MIP Stop Basis is input as basis points (1/100th of 1%).

The MIP process first determines the best partial solution using linear programming, as if the option had been set to "Partial". The cost of this solution then becomes the initial best bound, since rounding partial variables up or down will only increase the costs from there. Then, the MIP will create and evaluate several subproblems to find integer solutions and eliminate other possibilities. When a better solution is found, this reduces the best solution cost; when a path is eliminated, this increases the best bound cost. The process continues until the gap between these two costs is within the input tolerance.

Consider a simple example of a one-year capacity expansion problem with three potential projects (P1, P2, and P3) where each project has a maximum of 1. The first step is to solve the partial problem, and assume it provides these results:

- Node 0: Cost = $15.5 million, P1 = 0.3, P2 = 0.8, P3 = 0

The best bound is now $15.5 million, and the MIP will now start to evaluate the subproblems by branching on the partial solutions. For example, two subproblems will be created, one with the constraint P1 = 0 and the other with the constraint P1 = 1. These subproblems are then solved using linear programming, and assume these results:

- Node 1: Cost = $16.1 million, P1 = 0, P2 = 1, P3 = 0
- Node 2: Cost = $15.8 million, P1 = 1, P2 = 0.4, P3 = 0.1

Note that the project results for Node 1 are now all integers, and we have our first feasible solution. Node 2 still has partial projects, so the best bound now increases to $15.8 million. The gap between the best solution and best bound is 1.9%. If the MIP Stop Basis was set to 200, the process will stop and return Node 1 as the best solution. Assume that the MIP Stop Basis is lower, and the process will now branch on Node 2 by setting P2 = 0 and P2 = 1:

- Node 3: Cost = $15.9 million, P1 = 1, P2 = 0, P3 = 0.3
- Node 4: Cost = $16.2 million, P1 = 1, P2 = 1, P3 = 0

Node 4 is a feasible integer solution, but has a higher cost than Node 1, so the process does not do anything else with Node 4 (that "branch has been pruned"). Node 3 is a partial solution, so the best bound increases to $15.9 million, leaving a gap of 1.3% with the best solution (Node 1). Assume that the MIP Stop Basis is less than 120, so the process will now branch on Node 3 by setting P3 = 0 and P3 = 1:

- Node 5: Cost = $15.9 million, P1 = 1, P2 = 0, P3 = 0
- Node 6: Cost = $16.3 million, P1 = 1, P2 = 0, P3 = 1

The process is now left with only integer solutions, so the best bound and best solution are both $15.9 million, the gap is 0%, and Node 5 is the optimal solution.

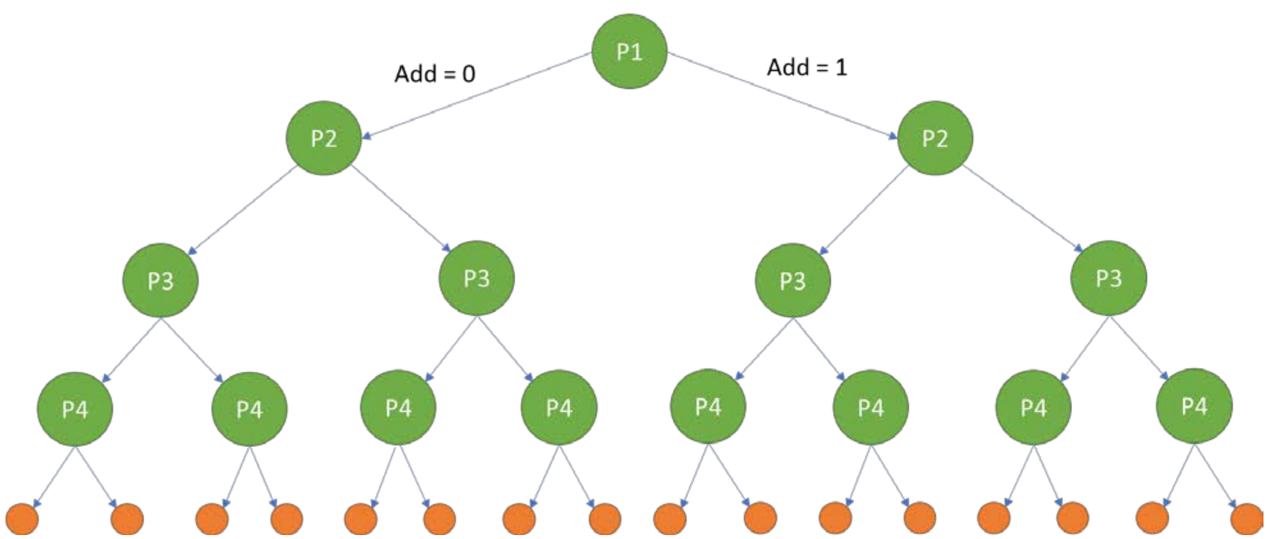
Objective Functions and the Unified Solution

Models like Strategist and EGEAS use dynamic programming to enumerate all feasible nodes. Each node is run through a non-linear probabilistic sub-module to determine production costs, which are added to the capital costs to determine the selected objective function value. The objective function is then ranked across all those nodes to determine the optimal plan. In this simple problem, there were 2 x 2 x 2

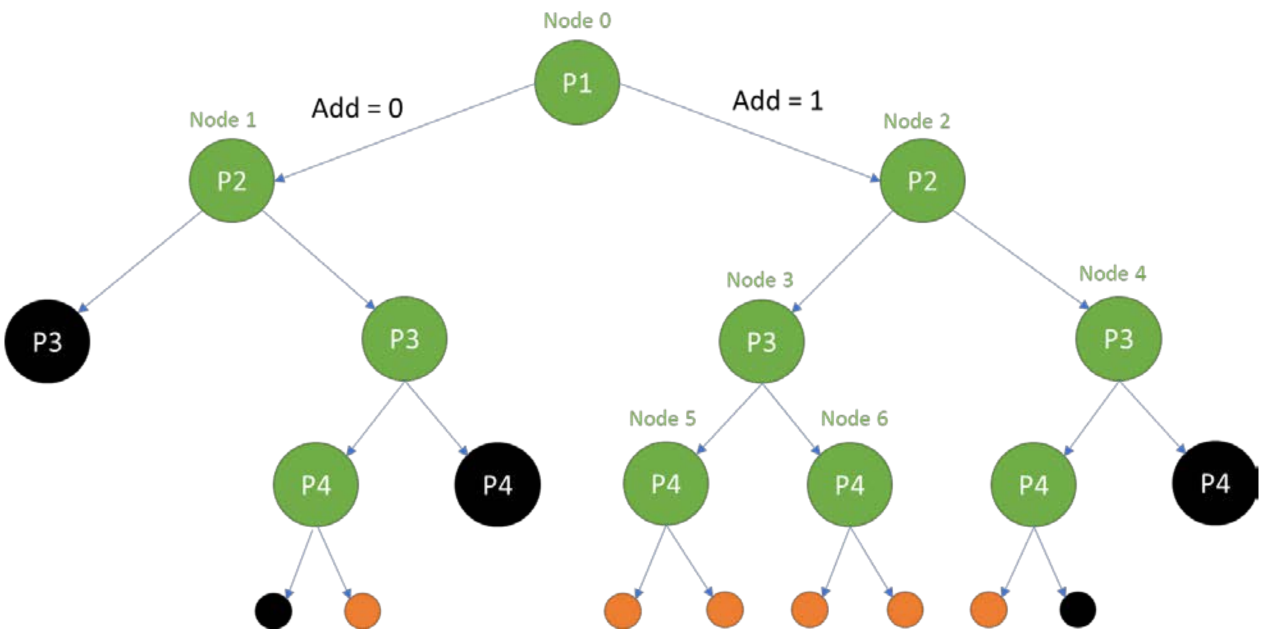
= 8 nodes to evaluate with dynamic programming, and 7 nodes with mixed integer programming. In a typical multi-year expansion problem, there are usually thousands of integer variables that can take values larger than 1. This makes the number of nodes to evaluate with a dynamic program skyrocket and requires additional constraints to be imposed to bring that number down. With mixed integer programming, the number of nodes is manageable since only those nodes that show promise are evaluated and used to look for other nodes.

With dynamic programming, the objective function can be distorted between the production cost sub-module and the capacity expansion decision. For example, if the objective function is to minimize total utility costs plus emission externalities, the ranking of nodes may pick up externality costs from the production cost sub-module, even if that was not included in the commitment and dispatch objective function. With mixed integer programming, there is no decoupling of capacity expansion, unit commitment, and economic dispatch, so all three of these decisions work together to minimize the single selected objective function. As an example, given the objective function of minimizing total utility costs plus emission externalities, a low-cost alternative might be to displace a MWh from a higher emitting resource, such as a coal-fired unit, with a MWh from a lower emitting unit such as either renewable or gas-fired generation. Depending on the design of the model, a dynamic programming algorithm might recognize one, both or neither of these options and possibly not produce the most economical alternative. Conversely, a mixed integer model that co-optimizes production cost and capacity expansion will evaluate all options for minimizing the objective function.

To illustrate this further, assume a fourth potential project, P4, is considered. The dynamic programming approach builds a decision tree, with a branch for every project decision (add 0 or 1). The result is 16 feasible solutions, shown in the figure below as orange leaves on the tree, each of which must be evaluated with the production cost sub-module:



Because the mixed integer process uses a unified solution, it knows the change in costs as the tree is being built and can prune branches that will always produce higher-cost feasible solutions. In the figure below, those pruned branches are shown in black, and the nodes from the example above are identified:



Another key advantage is that in the MIP process, each node can be evaluated using the solution to the prior node as a starting point, greatly reducing the processing time required to evaluate new nodes. The non-linear production cost sub-module of the dynamic program cannot "learn" as it goes, and each feasible solution must be evaluated from scratch.

To minimize the size of the problem that must be solved, EnCompass does not include the variables, constraints, and costs of any decisions which are fixed. This means that if the selections of one project in a capacity expansion optimization is "frozen" and the case is run again, the objective function values will be lower since the capital and fixed operating costs of that frozen project are not included. Since the convergence threshold is a percentage of the objective function, that gap becomes tighter, and a different overall plan with a slightly lower cost may be chosen.

The structure of the problem can also impact the selection of which variables are branched and the path that is used to find solutions. For example, removing limits that are never binding or resources and projects that are never utilized does not change the underlying economics, but it does make the problem smaller, which could lead to different approaches and different solutions that are both within the convergence tolerance. For capacity expansion problems where the MIP Stop Basis is set to a low value like 50 (0.5%), multiple solutions that are within that threshold should be considered to have comparable costs over the multi-year optimization period.

Xpress Optimization Suite

EnCompass uses the Xpress Optimization Suite from FICO to solve the linear and mixed integer problems described above. The branch-and-bound process can be sped up considerably by making better choices on which variables to branch on, and by performing heuristic searches for additional nodes. Xpress uses these techniques and others to provide the best possible performance for solving mixed integer problems.

One of the key techniques to reduce runtime for large problems is parallelism. This allows multiple "leaf" nodes to be solved simultaneously, based on the number of available computing cores and memory. As a result, the solution path may be different when solving using one set of computing resources versus another. This could produce two different solutions that are both feasible and within the input gap threshold.

Certificate of Service

I, Lynnette Sweet, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

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

xx electronic filing

Docket No. E002/RP-19-368

Dated this 30th day of June 2020

/s/

____

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