STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY ADVANCE PRUDENCE – MANKATO ENERGY CENTER – APPLICATION	CASE NO. PU-18-403 OAH FILE NO. 20190017

NSP Late-Filed Exhibit 3
Citations and Excerpts from NSP's Upper Midwest Resource Plan

A discussion of Northern States Power Company's analyses and modeling efforts culminating in the Company's "Preferred Plan" can be found at the following:

- Pages 92-123 of the Resource Plan which discusses the Company's analysis and results; and
- Appendix D – which provides a non-technical summary of the Resource Plan; and
- Appendix F-2 – which provides the various assumptions and inputs used for Xcel Energy's analysis; and
- Appendix F-3 – which provides the modelling outputs and comparisons of different resource planning options.

Excerpts of the above are attached for inclusion into the record in this proceeding.

64 PU-18-403 Filed 07/30/2019 Pages: 85
Late-filed Exhibit 3 - Citations and excerpts from NSP's 2019 Integrated Resource Plan, et al.
Northern States Power Company
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CHAPTER 5
ECONOMIC MODELING FRAMEWORK

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

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

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

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

I. ASSUMPTIONS

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

Important starting assumptions in our analysis include:

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

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

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

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

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

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

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

Additional cost –related assumptions include:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

II. SCENARIOS

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

A. Reference Case Scenario

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

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

B. Early Coal Family

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

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

C. Early Nuclear Family

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

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

D. Extend Nuclear Family

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

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

III. FUTURES SCENARIOS AND SENSITIVITIES

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

A. Futures Scenarios

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

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

Table 5-1: 2019 Resource Plan Futures Scenarios

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

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

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

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

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

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

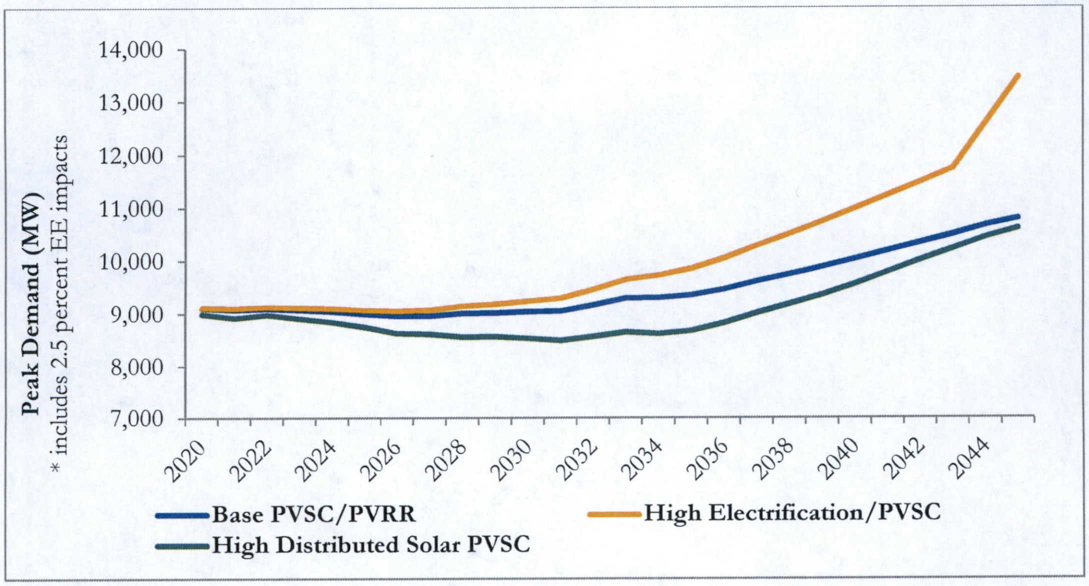


Figure 5-3: Fuel Price Assumptions, by Futures Scenario

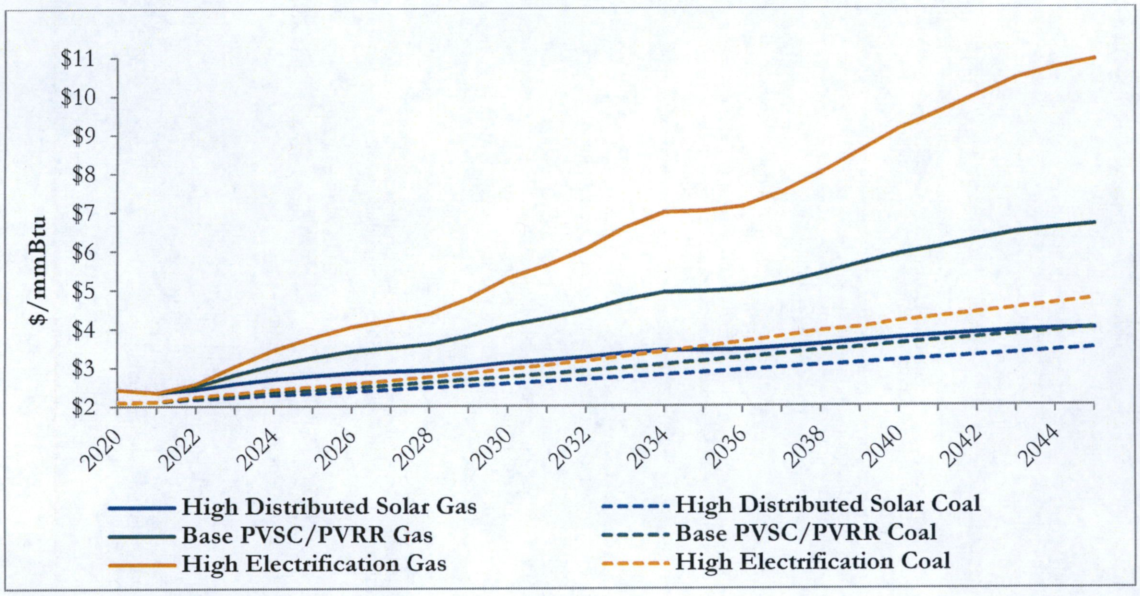


Figure 5-4: New Resource Cost Assumptions, by Futures Scenario ($/MWh; $/kW-mo)

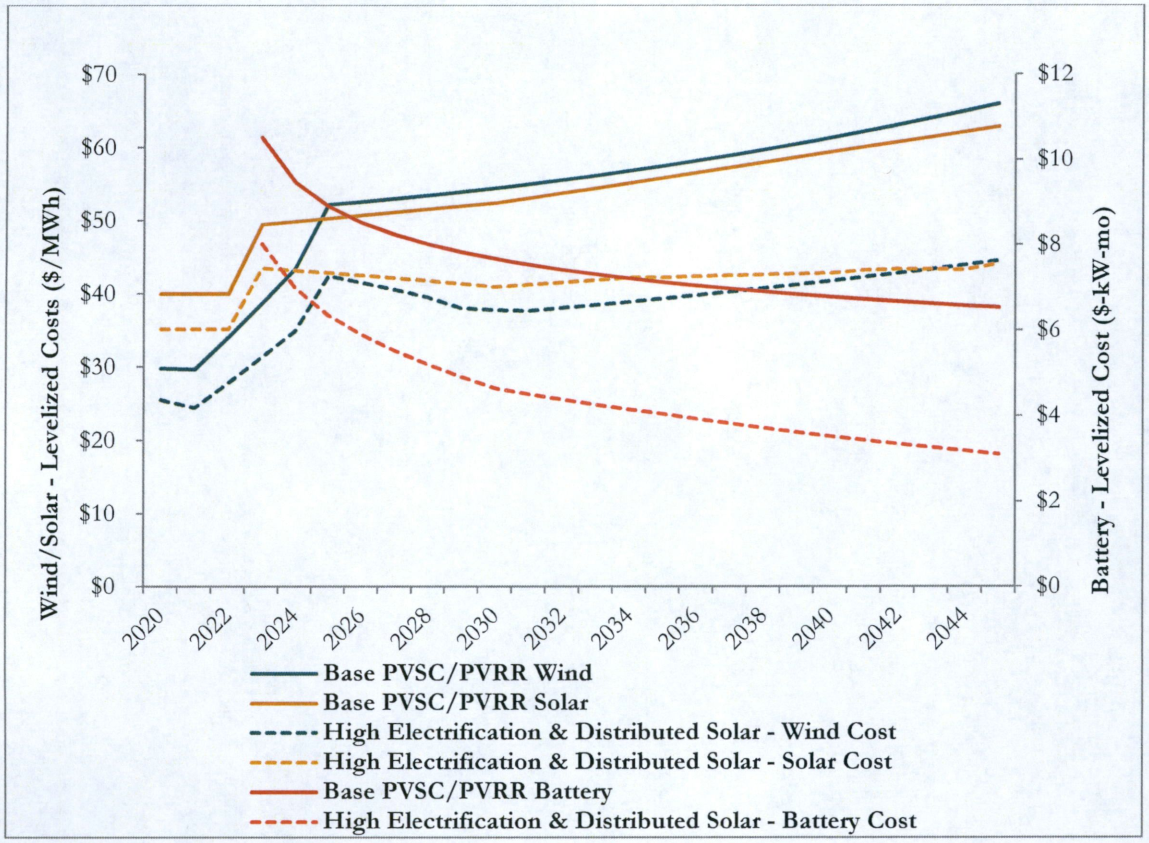
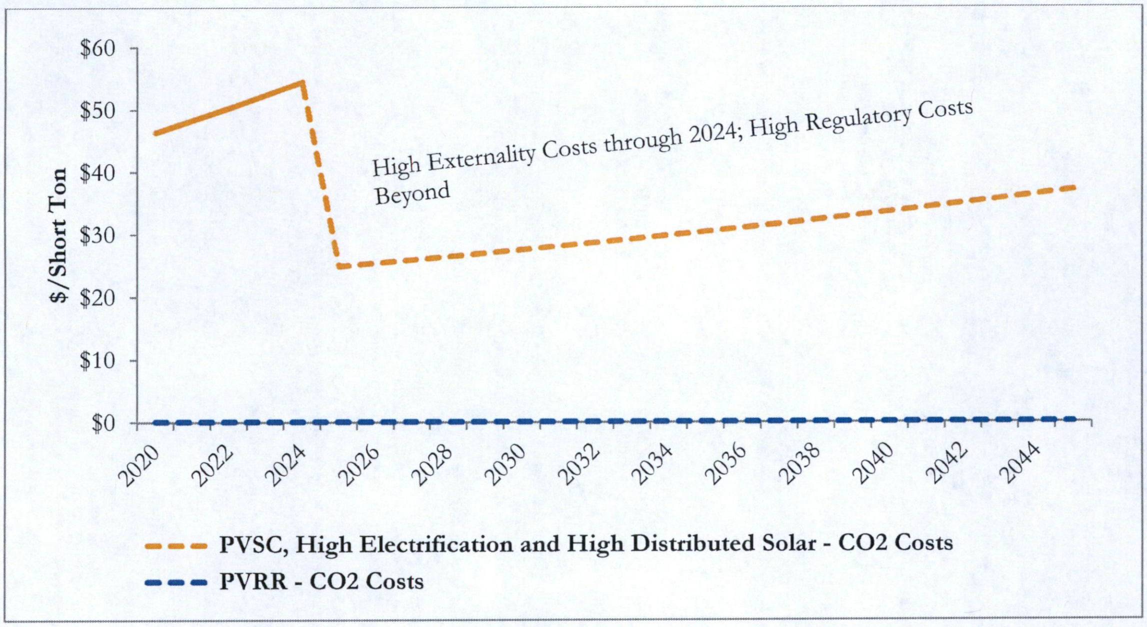


Figure 5-5: Carbon Emissions Cost Assumptions ($/Short Ton)



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

B. Traditional Sensitivities

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

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

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

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

cannot access the market to sell energy outside our system.

IV. STRATEGIST ANALYSIS AND RESULTS

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

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

A. Initial Full Optimization

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

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

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

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[7] Truncation occurs when the Strategist model has more viable plans for a given year than the internal memory is able to store. The total collection of plans is sorted by accumulated cost up to that year, and the highest cost plans are discarded and not analyzed further. The Company's model is set to a maximum of 2,500 saved plans per year.

[8] I.e. Effective Load Carrying Capability, or ELCC.

[9] We note that an independent analysis from consultant E3 highlighted similar concerns and also conducts expansion plan modeling to 2045.

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

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

B. Revised Targeted Optimization

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

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

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

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

[10] Applicable years vary by scenario.

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

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

C. Energy Efficiency and Demand Response Analysis

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

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

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

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

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

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

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

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

D. Final Scenario Analysis

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

[11] Minn. Stat. § 216B.2423

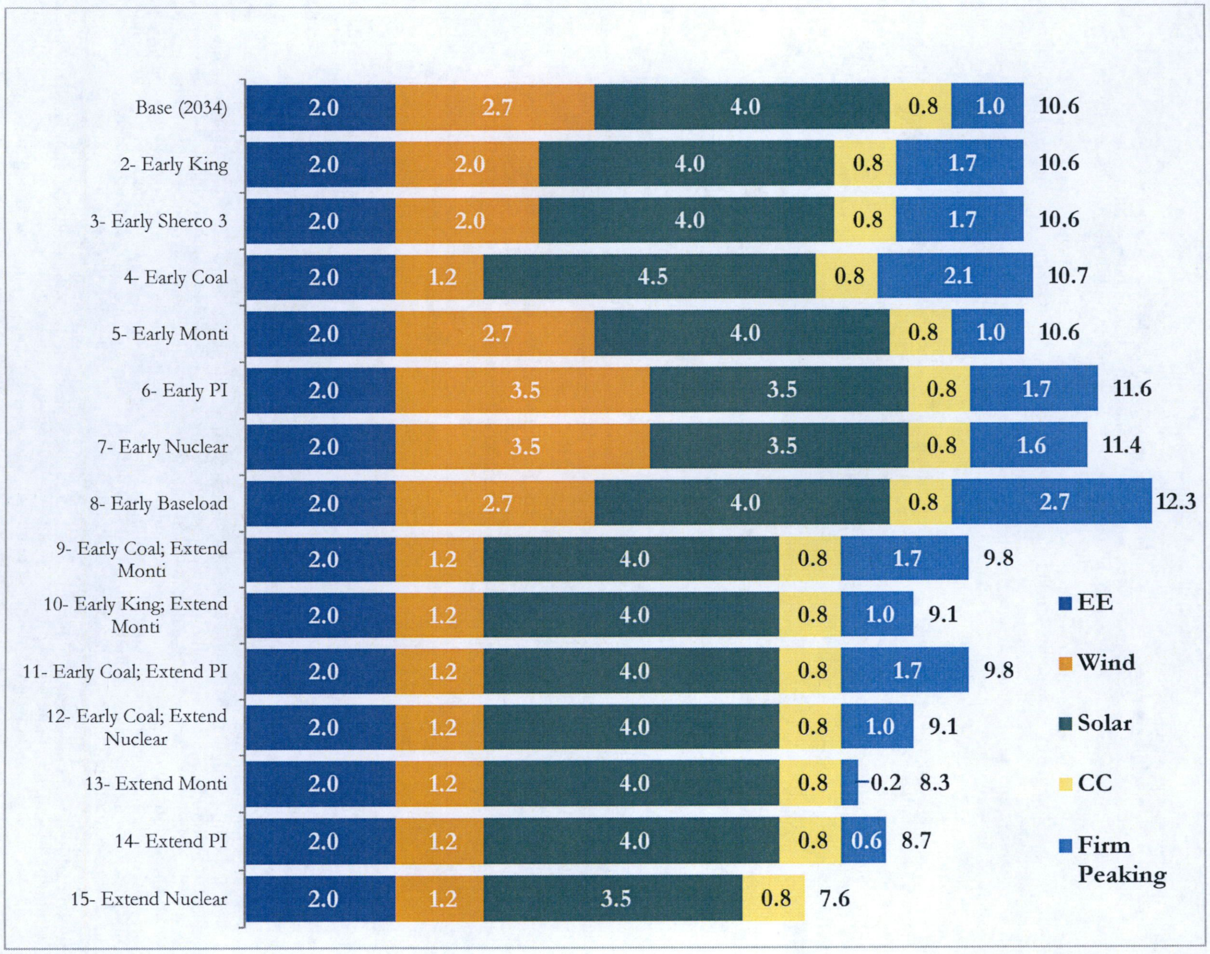
E. Modeling Results and Conclusions

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

1. *Capacity Additions and Emissions Reductions*

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

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

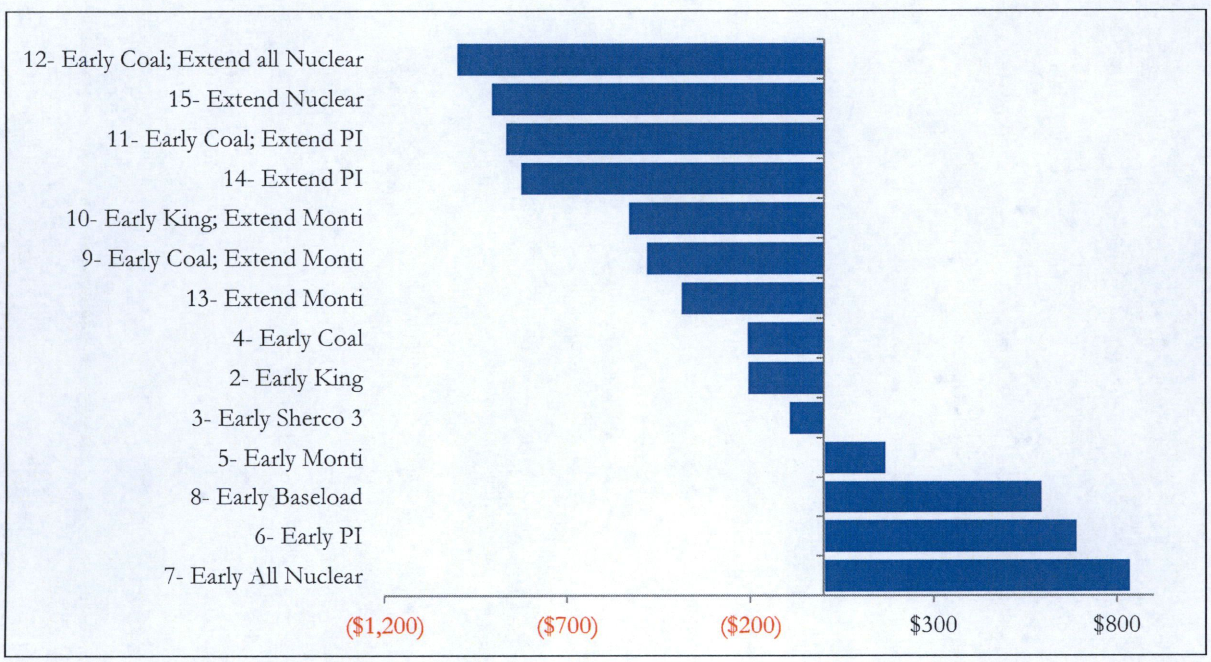


As the 80 percent carbon emissions reduction target was included as a modeling parameter, all the scenarios achieve this goal and remain under the emissions threshold from 2030 throughout the planning period. There is minimal variability between Scenarios on this measure, other than the timeframe in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

2. Present Value Costs

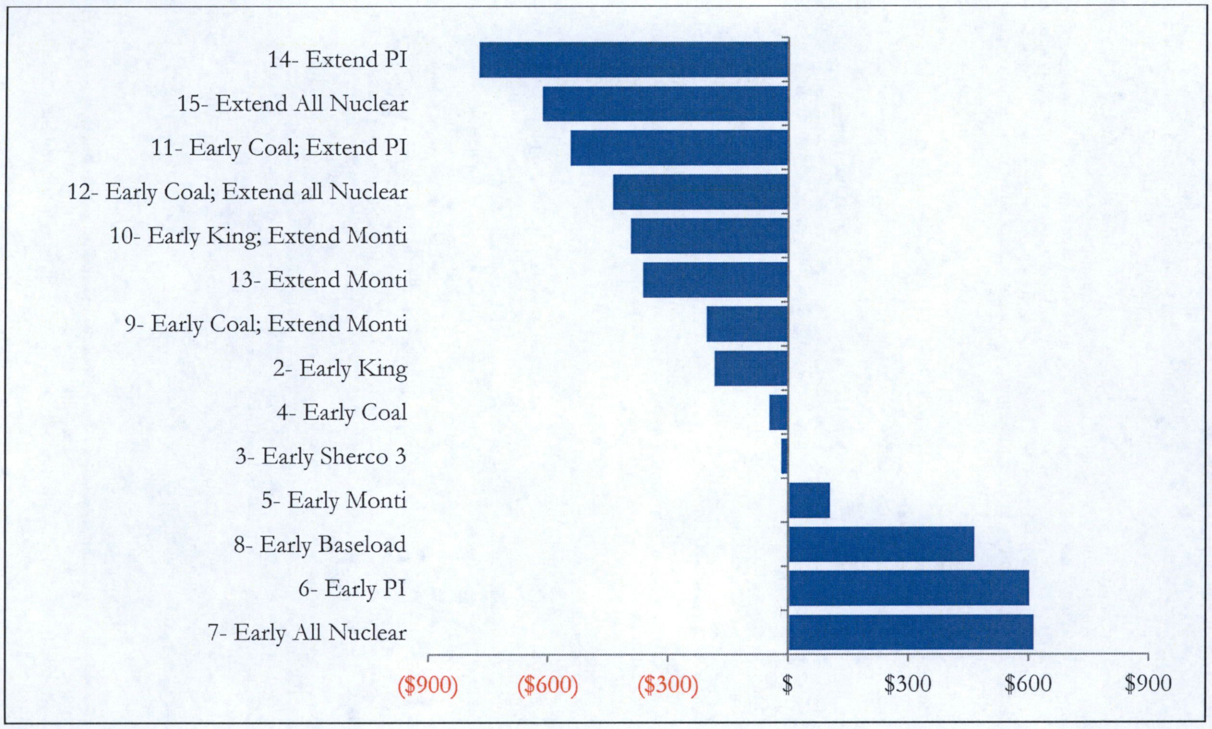
In general, plans that favored early coal retirements and nuclear extensions were the lowest cost plans, both in terms of PVSC and PVRR. The results for the 15 scenarios from the final modeling runs are shown below in Figures 5-7 and 5-8. The figures show the net present value (NPV) delta of modeled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

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



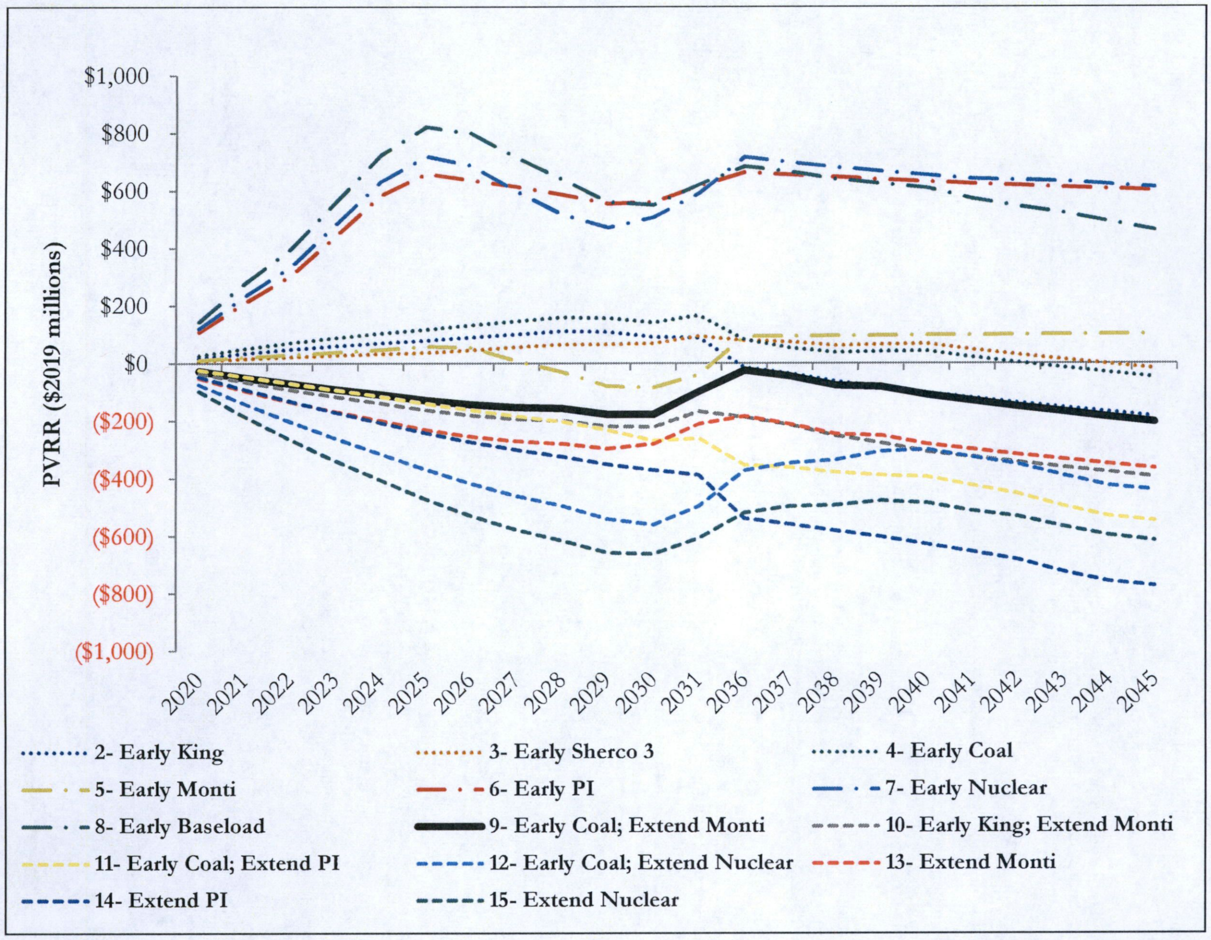
[12] Note that these PVRR and PVSC deltas shown depict NPV for 2020-2045.

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



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

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



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

3. *Additional Risk Metrics for Baseload Scenario Evaluation*

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

Table 5-3: Scenario Modeling Portfolio Risk Metrics

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

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

V. PREFERRED PLAN SELECTION AND ASSESSMENT

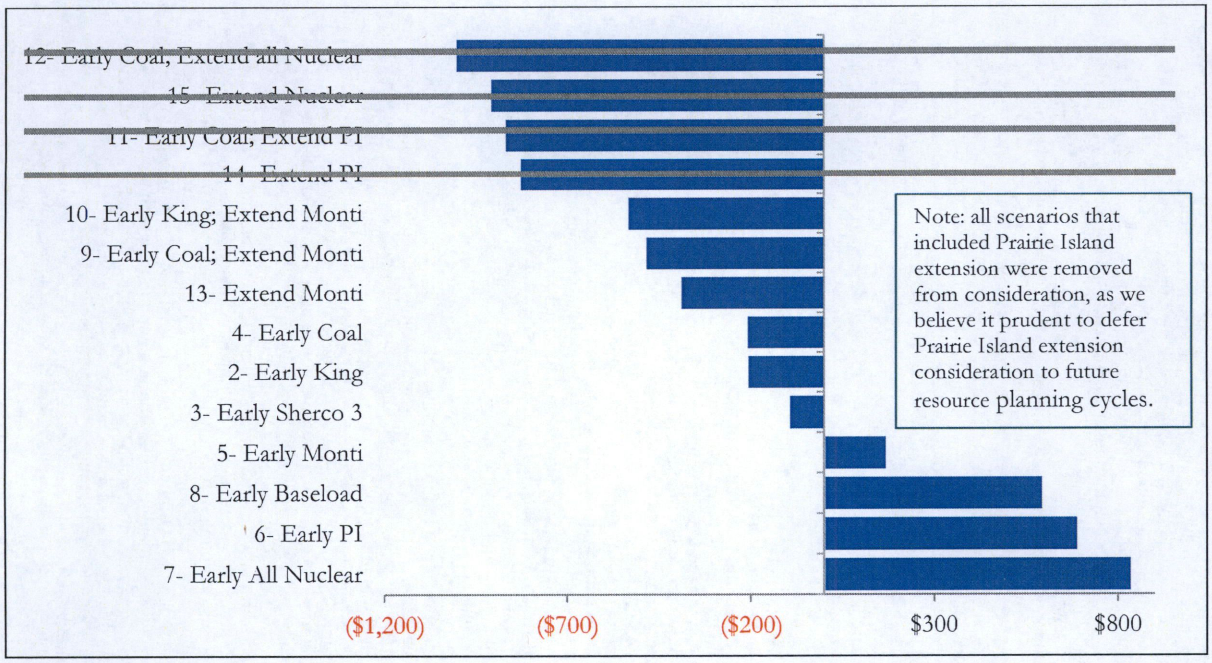
As described previously in this Chapter and in Chapter 4, we evaluated the PVRR and PVSC results of our 15 baseload scenarios, and how effectively each potential plan would meet our planning objectives, to determine which Scenario should form the basis of the Preferred Plan. Based on these outcomes,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

A. Baseload Study Analysis Results

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

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

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



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

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

B. Early Retirement of Sherco 3 by 2030

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

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

C. Demand Response Adjustment to Scenario 9

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

D. Futures Scenarios Results

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

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

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

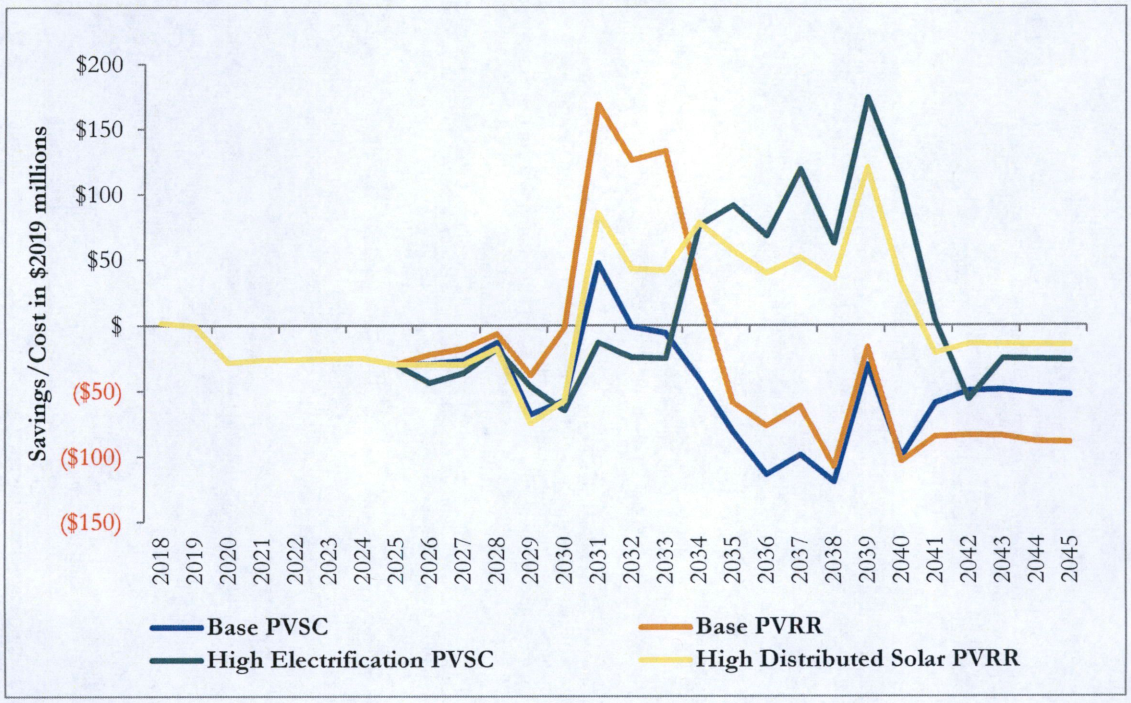
As demonstrated in the baseload scenario analysis and in Table 5-4, the Preferred Plan yields customer value of $203 million in the base PVRR and $461 million in the base PVSC scenarios. Early coal retirements paired with the Monticello extension yield

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

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

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

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



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

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

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

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

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

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

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

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

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

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

E. Preferred Plan Benefits

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

1. Cost

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

2. Risk

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

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

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

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

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

VI. CONCLUSION

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

APPENDIX D – NON-TECHNICAL SUMMARY

I. INTRODUCTION

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

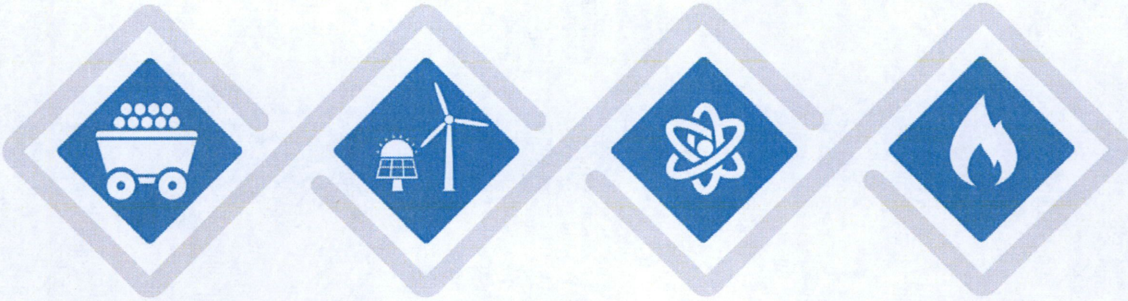
Our Resource Plan is founded on unprecedented levels of stakeholder engagement and technical analyses that examined an orderly retirement of our baseload generating units. We engaged a national expert on energy policy and economics, Dr. Susan Tierney with Analysis Group. Dr. Tierney not only brought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

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

Figure 1: Xcel Energy Integrated Resource Plan Objectives

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

Figure 2: Preferred Plan Highlights



Close coal plants
Retire the last of our coal plants in the Upper Midwest by 2030, a decade earlier than planned

Add renewables
Add at least 3,000 megawatts of solar by 2030, enough to power more than 650,000 homes each year, and complete our largest-ever wind expansion by 2022

Continue carbon-free nuclear
Start the process to gain regulatory approval to run our carbon-free Monticello nuclear plant until at least 2040

Bridge to carbon-free
Use natural gas-fired plants in the coming years as a reliable, cleaner source of electricity as we bridge toward future carbon-free technologies

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

II. A CHANGING PLANNING LANDSCAPE

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

A. Regional Reliability and Market Constructs

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

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

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

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

B. Distributed Energy Resources (DER)

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

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

C. Community and Employee Considerations

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

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

D. Customer Preferences

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

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

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

E. Supply and Technology Trends

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

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

F. Five State Integrated System

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

G. The Evolving NSP System

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

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

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

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

III. KEY CONSIDERATIONS OF THE PREFERRED PLAN

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

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

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

A. Environmental and Innovation

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

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

B. Reliability

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

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

C. Cost

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

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

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

D. Risk and Flexibility

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

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

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

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

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

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

IV. THE PREFERRED PLAN

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

A. Determining Customer Needs

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

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

Figure 3: Net Resource Need/Surplus Calculation

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

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

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

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

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

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

B. Reference Case Expansion Plan and Energy Mix

Table 2: Reference Case Annual Expansion Plan (MW)

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

C. Developing the Preferred Plan

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

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

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

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

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

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

D. Preferred Plan

Key components of our Preferred Plan include:

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

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

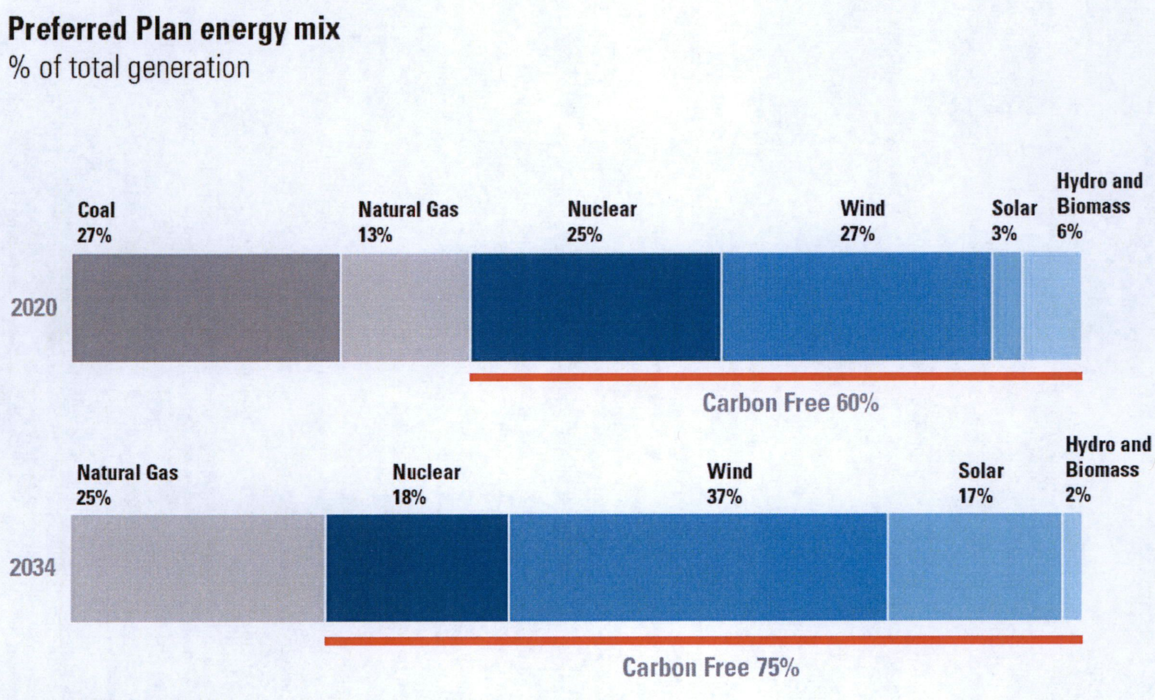
Table 3 below outlines the proposed timing, type, and size of resource additions comprising our Preferred Plan.

Table 3: Preferred Plan Resource Additions (MW)

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

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

Figure 4: Preferred Plan Energy Mix



Our Preferred Plan achieves several important goals:

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

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

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

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

V. FIVE-YEAR ACTION PLAN

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

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

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

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

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

In addition, as discussed in our last Resource Plan, system retirements will impact our current blackstart plans and we are currently analyzing our blackstart path to determine the best fit for our system needs. While we do not propose any action related to the system blackstart at this time, we anticipate addressing this in our next Resource Plan or earlier, if system needs dictate the need to do so.
Coal. As approved in our last Resource Plan, we will take action with MISO and retire Sherco Unit 2 in 2023, and intend to offer it into MISO on a seasonal basis until that time. Though outside the five-year action window, we are proposing to retire the remainder of our coal units (Sherco 2, Sherco 3 and King) before 2030. As with our previous plant retirements, we plan to begin working with our employees and host communities to prepare for this transition.

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

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

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

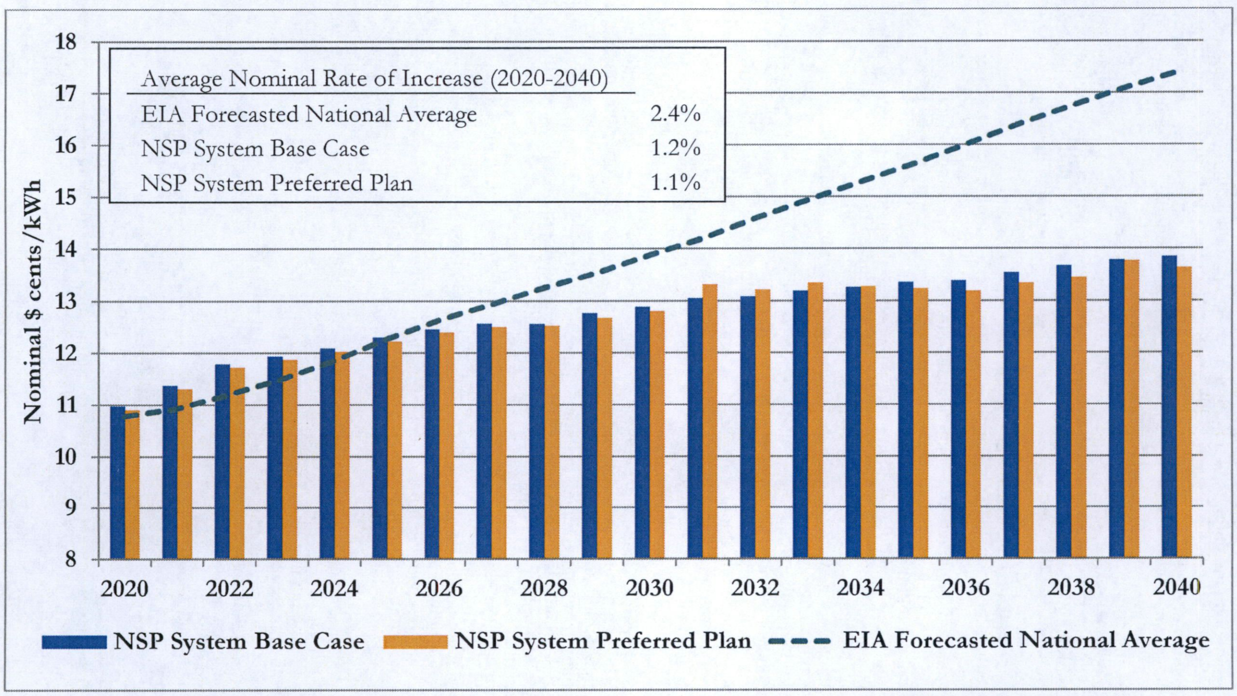
[8] Pending decision in Docket E,G002/D-19-161

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

VI. RATE IMPACTS

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

Figure 5: Preferred Plan Average Nominal Cost Comparison NSP System

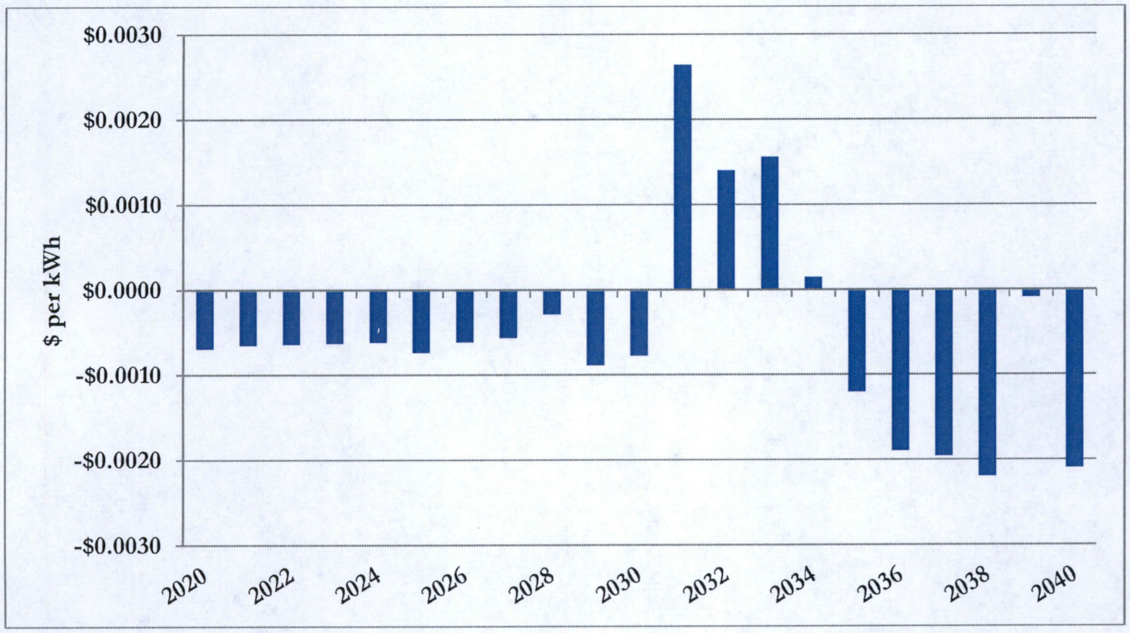


* *Notes: National energy cost forecast from Energy Information Administration (EIA) Annual Energy Outlook 2019, Table Energy Supply, Disposition, Prices and Emissions – Reference Case. End use prices, all sector average.*[9] The Preferred Plan and Reference *Plan lines include the costs of Solar Rewards*Community.*

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

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

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



VII. CONCLUSION

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

APPENDIX F2 – STRATEGIST MODELING ASSUMPTIONS & INPUTS

A. Discount Rate and Capital Structure

The discount rate used for levelized cost calculations and the present value of modeled costs is 6.53 percent. The rates shown below were calculated by taking a weighted average of each NSP jurisdiction's last allowed/settled electric retail rate case.

Table 1: Discount Rate and Capital Structure

Discount Rate and Capital Structure				
	Capital Structure	Allowed Return	Before Tax Electric WACC	After Tax Electric WACC
Long-Term Debt	46.16%	4.80%	2.22%	1.60%
Common Equity	52.35%	9.35%	4.90%	4.90%
Short-Term Debt	1.49%	3.65%	0.05%	0.04%
Total			**7.17%**	**6.53%**

B. Inflation Rates

The inflation rates are used for existing resources, generic resources, and other costs related to general inflationary trends in the modeling and are developed using long-term forecasts from Global Insight. The general inflation rate of 2% is from their long-term forecast for "Chained Price Index for Total Personal Consumption Expenditures" published in the second quarter of 2018.

C. Reserve Margin

The reserve margin at the time of MISO's peak is 8.4 percent from the 2018-2019 LOLE Study Report published November 2017. The coincidence factor between the NSP System and MISO system peak is 5 percent. Therefore, the effective reserve margin is:

$$(1 - 5\%) * (1 + 8.4\%) - 1 = 2.98\%.$$

D. CO_2 Costs

The PVSC Base Case CO2 values are based on the high environmental cost values for CO2 through 2024 (page 31 of the Minnesota Public Utilities Commission's Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.). All prices are converted to 2018 real dollars using the 2017 GPDIPD of

113.416 and then escalate at general inflation thereafter.

The PVSC Base Case values starting in 2025 are based on the "high" end of the range of regulated costs (see page 12 of MPUC Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs in Dockets No.E999/CI-07-1199 and E-999/DI-17-53 issued June 11, 2018). All prices escalate at general inflation.
The Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs requires four alternative scenarios to be run in addition to the PVSC Base Case. The Order Extending Deadline for Filing Next Resource Plan issued January 30, 2019 also requires a scenario using the midpoint of the Commission's most recently approved externalities and regulatory costs of carbon. The values in the PVSC Base Case and alternative scenarios are set out below.

Table 2: CO2 Costs

CO2 Costs ($ per short ton)						
Year	Low Environmental Cost	High Environmental Cost	Low Environmental/ Regulatory Costs	Mid Environmental/ Regulatory Costs	PVSC - High Environmental/ Regulatory Costs	PVRR - Omitting CO2 Cost Considerations
2018	$9.09	$42.76	$9.09	$25.92	$42.76	$0.00
2019	$9.49	$44.58	$9.49	$27.04	$44.58	$0.00
2020	$9.90	$46.45	$9.90	$28.18	$46.45	$0.00
2021	$10.32	$48.39	$10.32	$29.35	$48.39	$0.00
2022	$10.77	$50.38	$10.77	$30.57	$50.38	$0.00
2023	$11.22	$52.43	$11.22	$31.82	$52.43	$0.00
2024	$11.69	$54.55	$11.69	$33.12	$54.55	$0.00
2025	$12.16	$56.72	$5.00	$15.00	$25.00	$0.00
2026	$12.67	$58.97	$5.10	$15.30	$25.50	$0.00
2027	$13.17	$61.29	$5.20	$15.61	$26.01	$0.00
2028	$13.70	$63.67	$5.31	$15.92	$26.53	$0.00
2029	$14.24	$66.12	$5.41	$16.24	$27.06	$0.00
2030	$14.80	$68.64	$5.52	$16.56	$27.60	$0.00
2031	$15.37	$71.24	$5.63	$16.89	$28.15	$0.00
2032	$15.97	$73.91	$5.74	$17.23	$28.72	$0.00
2033	$16.57	$76.67	$5.86	$17.57	$29.29	$0.00
2034	$17.21	$79.50	$5.98	$17.93	$29.88	$0.00
2035	$17.85	$82.41	$6.09	$18.28	$30.47	$0.00
2036	$18.52	$85.41	$6.22	$18.65	$31.08	$0.00
2037	$19.20	$88.50	$6.34	$19.02	$31.71	$0.00
2038	$19.91	$91.68	$6.47	$19.40	$32.34	$0.00
2039	$20.62	$94.96	$6.60	$19.79	$32.99	$0.00
2040	$21.38	$98.32	$6.73	$20.19	$33.65	$0.00
2041	$22.14	$101.78	$6.86	$20.59	$34.32	$0.00
2042	$22.94	$105.34	$7.00	$21.00	$35.01	$0.00
2043	$23.74	$109.00	$7.14	$21.42	$35.71	$0.00
2044	$24.58	$112.76	$7.28	$21.85	$36.42	$0.00
2045	$25.43	$116.63	$7.43	$22.29	$37.15	$0.00
2046	$26.33	$120.61	$7.58	$22.73	$37.89	$0.00
2047	$27.23	$124.71	$7.73	$23.19	$38.65	$0.00
2048	$28.17	$128.92	$7.88	$23.65	$39.42	$0.00
2049	$29.12	$133.24	$8.04	$24.13	$40.21	$0.00
2050	$30.12	$137.69	$8.20	$24.61	$41.02	$0.00
2051	$31.14	$142.26	$8.37	$25.10	$41.84	$0.00
2052	$32.18	$146.97	$8.53	$25.60	$42.67	$0.00
2053	$33.26	$151.80	$8.71	$26.12	$43.53	$0.00
2054	$34.36	$156.76	$8.88	$26.64	$44.40	$0.00
2055	$35.50	$161.87	$9.06	$27.17	$45.28	$0.00
2056	$36.66	$167.11	$9.24	$27.71	$46.19	$0.00
2057	$37.86	$172.51	$9.42	$28.27	$47.11	$0.00

E. All Other Externality Costs

The values of the criteria pollutants are derived from the high and low values for each of the 3 locations, as determined in the Minnesota Commission Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.

The midpoint externality costs are the average of the low and high values. All prices are escalated to 2018 real dollars using the 2017 GPDIPD of 113.416. The high, low and midpoint externality costs will be used in the CO2 sensitivities as described above.

Table 3: Externality Costs

MPUC Low Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$6,116	$4,829	$3,643	$0
NOx	$2,934	$2,622	$2,110	$28
PM2.5	$10,697	$6,856	$3,654	$872
CO	$1.65	$1.17	$0.31	$0.31
Pb	$4,857	$2,562	$624	$624

MPUC High Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$15,288	$12,030	$8,878	$0
NOx	$8,390	$7,798	$6,771	$158
PM2.5	$26,721	$17,091	$8,973	$1,327
CO	$3.51	$2.08	$0.63	$0.63
Pb	$6,011	$3,094	$695	$695

MPUC Midpoint Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$10,702	$8,430	$6,261	$0
NOx	$5,662	$5,210	$4,441	$93
PM2.5	$18,709	$11,974	$6,313	$1,099
CO	$2.58	$1.63	$0.47	$0.47
Pb	$5,434	$2,828	$659	$659

F. Demand and Energy Forecast

The Company's fall 2018 load forecast is used as the base assumption and assumes that EV impacts grow through 2023 are then held constant for the remaining forecast period. The energy efficiency (EE) forecast included in this forecast assumes impacts at a 75 percent rebate level which equals roughly 1.5 percent of sales through the planning period.

The "Load Forecast with 1.5% EE" shown in Table 4 below is the starting point for the Strategist load inputs. In all modeling scenarios, the "1.5% EE" is removed - the removal of these EE program effects, which have a 14-year life, impacts the load forecast through 2047. In its place, three EE Bundles (discussed below) are included in Strategist as Proview Alternatives and any number of these bundles (from 0 to all 3) is allowed to be selected as part of the optimization process. The resulting forecast, before the optimized EE bundles are added, is shown below in Table 4 as "Forecast Without 1.5% EE." The forecasts shown do not include the impact of DG solar, as DG solar is modeled as a resource in Strategist, not a load modifier.

Table 4: Strategist Demand and Energy Forecast

Demand and Energy Forecast				
	Demand (MW)		Energy (GWh)	
Year	Forecast with 1.5% EE	Forecast without 1.5% EE	Forecast with 1.5% EE	Forecast without 1.5% EE
2018	9,152	9,152	43,914	43,914
2019	9,136	9,136	43,798	43,798
2020	9,156	9,227	43,865	44,310
2021	9,191	9,333	43,560	44,447
2022	9,251	9,464	43,529	44,860
2023	9,285	9,569	43,394	45,168
2024	9,329	9,684	43,425	45,650
2025	9,354	9,780	43,257	45,919
2026	9,403	9,900	43,281	46,386
2027	9,487	10,055	43,493	47,042
2028	9,593	10,262	44,089	48,093
2029	9,635	10,403	43,972	48,408
2030	9,697	10,567	44,130	49,010
2031	9,740	10,713	44,172	49,496
2032	9,856	10,956	44,661	50,445
2033	10,005	11,211	44,875	51,087
2034	10,137	11,343	45,232	51,443
2035	10,248	11,368	45,534	51,302
2036	10,374	11,408	46,042	51,382
2037	10,482	11,430	46,126	51,006
2038	10,576	11,438	46,287	50,723
2039	10,674	11,449	46,541	50,534
2040	10,777	11,467	46,946	50,505
2041	10,873	11,476	46,975	50,081
2042	10,964	11,481	47,143	49,805
2043	11,057	11,488	47,407	49,626
2044	11,169	11,514	47,823	49,603
2045	11,241	11,500	47,879	49,210
2046	11,328	11,500	48,076	48,964
2047	11,424	11,510	48,372	48,816
2048	11,536	11,536	48,977	48,977
2049	11,626	11,626	48,811	48,811
2050	11,715	11,715	49,042	49,042
2051	11,804	11,804	49,274	49,274
2052	11,893	11,901	49,640	49,640
2053	11,982	11,992	49,736	49,736
2054	12,071	12,083	49,968	49,968
2055	12,160	12,174	50,199	50,199
2056	12,249	12,265	50,567	50,567
2057	12,339	12,356	50,662	50,662

The low load sensitivity includes high customer-adoption-based DG/DER growth and higher EE savings, which reduces load. The high load sensitivity includes high electrification load. These assumptions are shown in Table 5 and Table 6, and are incremental/decremental to the forecast shown in Table 4.

Table 5: High Load Sensitivity

High Electrification		
Year	Energy (GWh)	Demand (MW)
2018	35	8
2019	46	6
2020	59	7
2021	166	20
2022	276	33
2023	390	47
2024	507	62
2025	627	77
2026	785	96
2027	976	117
2028	1,194	141
2029	1,579	171
2030	2,122	207
2031	2,802	250
2032	3,622	302
2033	4,593	362
2034	5,706	430
2035	6,969	509
2036	8,320	592
2037	9,751	681
2038	11,248	772
2039	12,797	866
2040	14,387	961
2041	15,950	1,055
2042	17,472	1,146
2043	18,940	1,245
2044	20,341	1,930
2045	21,665	2,660
2046	22,904	3,318
2047	24,054	3,945
2048	25,112	4,800
2049	26,076	5,056
2050	26,947	5,554
2051	28,051	6,093
2052	29,061	6,564
2053	30,072	7,041
2054	31,083	7,528
2055	32,093	8,021
2056	33,104	8,496
2057	34,115	8,984

**Demand values are coincident to system peak*

Table 6: Low Load Sensitivity

High DER Growth			
Year	Energy (GWh)	ELCC (MW)	Demand (Nameplate MW)
2018	0	0	0
2019	0	0	0
2020	0	0	0
2021	189	72	144
2022	173	66	131
2023	159	60	121
2024	144	55	109
2025	135	51	103
2026	230	87	175
2027	228	87	173
2028	369	140	280
2029	377	143	286
2030	432	164	328
2031	490	186	373
2032	553	210	420
2033	617	235	469
2034	687	261	522
2035	760	289	578
2036	840	319	637
2037	920	350	700
2038	1,007	383	766
2039	1,099	418	836
2040	1,200	455	910
2041	1,225	466	931
2042	1,187	451	902
2043	1,148	437	873
2044	1,112	422	844
2045	1,070	407	814
2046	1,014	385	771
2047	974	370	740
2048	935	354	709
2049	891	339	677
2050	850	323	646
2051	799	304	607
2052	759	287	575
2053	701	266	532
2054	657	249	498
2055	607	230	461
2056	559	211	422
2057	506	192	383

G. Energy Efficiency Bundles

The EE "Program" and "Maximum" Bundles are based on the Minnesota Department of Commerce's Minnesota Energy Efficiency Potential Study: 2020-2029 published December 4, 2018. The "Optimal" Bundle was developed by the Company. The bundles are incremental to the "Forecast without 1.5% EE" shown in Table 4. They are also dependent on the Bundle before it being selected (i.e. Bundle 2 cannot be selected if Bundle 1 is not selected). The Bundles are included in Strategist as Proview Alternatives and any number of these Bundles (from 0 to all 3) is allowed to be selected as part of the optimization process.

Table 7: Energy Efficiency Bundles

	Energy(MWh)			Demand (MW)			Costs ($000)		
Year	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max
2018	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0
2020	621	43	231	97	18	36	100,989	12,598	148,331
2021	1,326	91	493	207	38	77	113,525	13,905	167,221
2022	1,913	148	702	301	60	113	121,239	21,425	177,197
2023	2,555	211	928	407	86	154	133,614	23,931	196,474
2024	3,094	279	1,110	520	116	197	148,406	26,120	217,388
2025	3,629	346	1,289	635	146	241	152,433	26,077	223,293
2026	4,330	414	1,533	759	176	289	160,445	26,236	233,779
2027	5,054	482	1,785	886	206	338	167,718	26,637	242,963
2028	5,785	551	2,040	1,012	235	387	174,161	27,018	249,373
2029	6,454	606	2,280	1,127	259	432	162,170	23,442	233,114
2030	7,110	659	2,516	1,241	283	477	162,170	23,442	233,114
2031	7,753	710	2,748	1,354	307	522	162,170	23,442	233,114
2032	8,339	760	2,960	1,460	329	564	162,170	23,442	233,114
2033	8,909	808	3,168	1,564	352	605	162,170	23,442	233,114
2034	9,464	857	3,370	1,667	374	646	162,170	23,442	233,114
2035	9,250	846	3,294	1,648	370	638	0	0	0
2036	8,739	835	3,073	1,579	366	600	0	0	0
2037	8,088	789	2,829	1,470	347	557	0	0	0
2038	7,450	741	2,590	1,369	327	517	0	0	0
2039	6,841	685	2,372	1,267	304	475	0	0	0
2040	6,197	626	2,144	1,154	278	430	0	0	0
2041	5,543	562	1,919	1,036	250	384	0	0	0
2042	4,871	499	1,685	916	221	337	0	0	0
2043	4,220	434	1,457	796	191	291	0	0	0
2044	3,561	377	1,218	678	165	245	0	0	0
2045	2,912	318	990	562	139	201	0	0	0
2046	2,276	265	761	451	116	156	0	0	0
2047	1,746	212	573	349	93	117	0	0	0
2048	1,216	159	384	248	70	79	0	0	0
2049	686	106	195	146	46	40	0	0	0
2050	156	53	7	45	23	1	0	0	0
2051	0	0	0	0	0	0	0	0	0
2052	0	0	0	0	0	0	0	0	0
2053	0	0	0	0	0	0	0	0	0
2054	0	0	0	0	0	0	0	0	0
2055	0	0	0	0	0	0	0	0	0
2056	0	0	0	0	0	0	0	0	0
2057	0	0	0	0	0	0	0	0	0

***Demand values are coincident to system peak*

H. Demand Response Forecast

The base demand response forecast was developed by the Company and is included in all scenarios and sensitivities. The three demand response "Bundles" are from the Brattle Potential Study provided as Appendix G2. The Bundles are incremental to the base demand response forecast and, the same as for EE, are dependent on the Bundle before it being selected (i.e. Bundle 2 cannot be selected if Bundle 1 is not selected). These Bundles are included in Strategist as Proview Alternatives and any number of the Bundles (from 0 to all 3) is allowed to be selected as part of the optimization process.

Table 8: Demand Response Forecast

Demand (MW) Adjusted For Reserve Margin					Costs ($000)		
Year	Base Demand Response Forecast	Bundle 1	Bundle 2	Bundle 3	Bundle 1	Bundle 2	Bundle 3
2018	848	0	0	0	0	0	0
2019	924	0	0	0	0	0	0
2020	940	270	107	89	14,380	7,659	11,311
2021	955	290	112	97	15,724	8,150	12,587
2022	970	312	116	106	17,212	8,676	14,016
2023	989	322	120	110	18,124	9,137	14,758
2024	1007	339	132	101	19,512	10,277	13,829
2025	1023	380	145	92	22,305	11,459	12,858
2026	1038	392	151	93	23,475	12,207	13,326
2027	1053	406	159	95	24,786	13,080	13,845
2028	1066	421	168	97	26,245	14,086	14,418
2029	1054	438	178	99	27,859	15,231	15,047
2030	1043	456	189	101	29,637	16,522	15,734
2031	1032	476	201	104	31,551	17,926	16,467
2032	1021	497	214	106	33,612	19,451	17,251
2033	1010	519	227	109	35,832	21,109	18,088
2034	1000	542	242	112	38,224	22,911	18,984
2035	990	567	257	116	40,802	24,870	19,943
2036	981	594	274	119	43,582	26,999	20,971
2037	972	630	293	125	46,580	29,313	22,072
2038	963	660	312	129	49,814	31,829	23,253
2039	954	692	332	133	53,305	34,564	24,522
2040	945	726	353	138	57,073	37,537	25,884
2041	937	726	353	138	58,215	38,288	26,402
2042	929	726	353	138	59,379	39,054	26,930
2043	921	726	353	138	60,566	39,835	27,468
2044	913	726	353	138	61,778	40,632	28,018
2045	906	726	353	138	63,013	41,444	28,578
2046	898	726	353	138	64,274	42,273	29,150
2047	891	726	353	138	65,559	43,118	29,733
2048	884	726	353	138	66,870	43,981	30,327
2049	876	726	353	138	68,208	44,860	30,934
2050	869	726	353	138	69,572	45,758	31,552
2051	862	726	353	138	70,963	46,673	32,183
2052	854	726	353	138	72,382	47,606	32,827
2053	847	726	353	138	73,830	48,558	33,484
2054	839	726	353	138	75,307	49,530	34,153
2055	832	726	353	138	76,813	50,520	34,836
2056	825	726	353	138	78,349	51,531	35,533
2057	817	726	353	138	79,916	52,561	36,244

**Demand values are coincident to system peak.*

I. Fuel Price Forecasts

The natural gas prices are developed using a blend of market information (New York Mercantile Exchange futures prices) and long-term fundamentally-based forecasts from Wood Mackenzie, Cambridge Energy Research Associates (CERA) and Petroleum Industry Research Associates (PIRA).

Coal price forecasts are developed using two major inputs: the current contract volumes and prices combined with current estimates of required spot volumes and prices to cover non-contracted coal needs. Typically coal volumes and prices are under contract on a plant by plant basis for a one to five year term with annual spot volumes filling the estimated fuel requirements of the coal plant based on recent unit dispatch. The spot coal price forecasts are developed from price forecasts provided by Wood Mackenzie, JD Energy, and John T Boyd Company, as well as price points from recent Request for Proposal (RFP) responses for coal supply. Added to the spot coal forecast, which is just for the coal commodity, are: transportation charges, SO_2 costs, freeze control and dust suppressant, as required.

In addition to resources that exist within the NSP System, the Company is a participant in the MISO Market. Electric power market prices are developed from fundamentally-based forecasts from Wood Mackenzie, CERA and PIRA using a similar methodology as is used for the gas price forecast. Table 9 below shows the market prices under zero CO_2 cost assumptions. The market purchases and sales limit for transaction volume between the Company and MISO is 1,350 MWh/h in 2018, 1,800 MWh/h from 2019-2022, and 2,300 MWh/h for 2023 and beyond.

High and low price sensitivities were performed by adjusting the growth rate up and down by 50 percent from the base forecast starting in year 2022.

Table 9: Fuel and Market Price Forecasts

	Base Price Forecast				Low Price Forecast				High Price Forecast			
	Fuel Price ($/mmBTu)		Market Price ($/MWh)		Fuel Price ($/mmBTu)		Market Price ($/MWh)		Fuel Price ($/mmBTu)		Market Price ($/MWh)	
Year	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak
2018	$2.19	$2.74	$28.60	$21.61	$2.19	$2.74	$28.60	$21.61	$2.19	$2.74	$28.60	$21.61
2019	$2.08	$2.67	$27.10	$21.12	$2.08	$2.67	$27.10	$21.12	$2.08	$2.67	$27.10	$21.12
2020	$2.11	$2.44	$24.36	$18.97	$2.11	$2.44	$24.36	$18.97	$2.11	$2.44	$24.36	$18.97
2021	$2.14	$2.37	$23.37	$17.97	$2.14	$2.37	$23.37	$17.97	$2.14	$2.37	$23.37	$17.97
2022	$2.23	$2.52	$24.93	$19.30	$2.19	$2.44	$24.18	$18.72	$2.26	$2.59	$25.68	$19.88
2023	$2.29	$2.82	$28.39	$22.16	$2.24	$2.59	$26.08	$20.36	$2.34	$3.06	$30.80	$24.04
2024	$2.37	$3.07	$30.69	$23.93	$2.29	$2.70	$27.02	$21.07	$2.45	$3.47	$34.66	$27.03
2025	$2.42	$3.26	$32.82	$25.48	$2.34	$2.79	$28.06	$21.79	$2.51	$3.79	$38.13	$29.61
2026	$2.48	$3.42	$34.50	$27.03	$2.38	$2.85	$28.81	$22.58	$2.59	$4.06	$41.02	$32.14
2027	$2.55	$3.51	$35.03	$27.53	$2.43	$2.89	$28.86	$22.68	$2.68	$4.24	$42.22	$33.19
2028	$2.62	$3.60	$35.52	$27.78	$2.48	$2.93	$28.90	$22.60	$2.77	$4.40	$43.35	$33.90
2029	$2.69	$3.82	$37.34	$29.17	$2.54	$3.02	$29.53	$23.07	$2.87	$4.79	$46.83	$36.59
2030	$2.76	$4.09	$39.20	$30.60	$2.59	$3.13	$29.95	$23.38	$2.97	$5.31	$50.84	$39.69
2031	$2.84	$4.26	$41.18	$32.22	$2.64	$3.19	$30.85	$24.13	$3.07	$5.63	$54.45	$42.60
2032	$2.92	$4.47	$42.61	$33.54	$2.70	$3.27	$31.17	$24.53	$3.18	$6.05	$57.66	$45.38
2033	$3.00	$4.74	$45.01	$35.50	$2.75	$3.37	$31.99	$25.24	$3.30	$6.60	$62.64	$49.41
2034	$3.08	$4.93	$46.64	$37.01	$2.81	$3.44	$32.51	$25.80	$3.42	$6.99	$66.15	$52.51
2035	$3.17	$4.94	$46.91	$37.38	$2.87	$3.44	$32.65	$26.02	$3.54	$7.02	$66.64	$53.11
2036	$3.26	$5.00	$46.72	$37.35	$2.93	$3.46	$32.33	$25.85	$3.67	$7.15	$66.75	$53.37
2037	$3.35	$5.17	$48.19	$38.46	$2.99	$3.52	$32.81	$26.19	$3.81	$7.51	$69.97	$55.84
2038	$3.44	$5.40	$49.56	$40.01	$3.06	$3.60	$33.03	$26.67	$3.95	$8.00	$73.47	$59.32
2039	$3.51	$5.65	$51.50	$41.70	$3.11	$3.68	$33.54	$27.16	$4.05	$8.57	$78.09	$63.23
2040	$3.61	$5.90	$53.12	$43.28	$3.18	$3.76	$33.87	$27.60	$4.20	$9.14	$82.24	$67.00
2041	$3.69	$6.08	$54.73	$44.58	$3.24	$3.82	$34.39	$28.01	$4.31	$9.55	$85.97	$70.04
2042	$3.77	$6.27	$56.47	$46.00	$3.30	$3.88	$34.93	$28.46	$4.42	$10.01	$90.07	$73.38
2043	$3.85	$6.46	$58.13	$47.35	$3.36	$3.94	$35.44	$28.88	$4.53	$10.45	$94.04	$76.61
2044	$3.93	$6.57	$59.12	$48.17	$3.43	$3.97	$35.75	$29.12	$4.65	$10.72	$96.46	$78.59
2045	$4.02	$6.66	$59.90	$48.80	$3.49	$4.00	$35.99	$29.32	$4.77	$10.93	$98.37	$80.14
2046	$4.11	$6.77	$60.93	$49.63	$3.56	$4.03	$36.29	$29.57	$4.89	$11.21	$100.88	$82.19
2047	$4.20	$6.96	$62.70	$51.07	$3.63	$4.09	$36.82	$29.99	$5.02	$11.69	$105.27	$85.75
2048	$4.29	$7.17	$64.55	$52.57	$3.70	$4.15	$37.37	$30.44	$5.15	$12.21	$109.93	$89.54
2049	$4.38	$7.25	$65.25	$53.15	$3.77	$4.17	$37.57	$30.60	$5.29	$12.41	$111.72	$91.01
2050	$4.48	$7.37	$66.39	$54.08	$3.85	$4.21	$37.90	$30.87	$5.43	$12.73	$114.66	$93.38
2051	$4.58	$7.52	$67.67	$55.12	$3.92	$4.25	$38.27	$31.17	$5.57	$13.10	$117.97	$96.08
2052	$4.68	$7.66	$68.99	$56.19	$4.00	$4.29	$38.64	$31.47	$5.72	$13.49	$121.42	$98.90
2053	$4.79	$7.81	$70.33	$57.28	$4.08	$4.33	$39.02	$31.78	$5.87	$13.88	$124.95	$101.77
2054	$4.89	$7.96	$71.68	$58.39	$4.16	$4.38	$39.39	$32.08	$6.03	$14.28	$128.56	$104.71
2055	$5.00	$8.12	$73.07	$59.51	$4.25	$4.42	$39.77	$32.39	$6.18	$14.69	$132.28	$107.74
2056	$5.11	$8.27	$74.48	$60.67	$4.33	$4.46	$40.16	$32.71	$6.34	$15.12	$136.13	$110.87
2057	$5.21	$8.43	$75.92	$61.83	$4.41	$4.50	$40.54	$33.02	$6.49	$15.55	$140.05	$114.06

**Coal prices are delivered prices, while gas and market prices are hub prices.*

J. Baseload Retirement "Leave Behind" Costs

Based on the MISO Y2 retirement studies performed on existing coal and nuclear resources, the Company developed transmission reinforcement or "leave behind" estimates, which reflect costs required to mitigate localized grid impacts of the retirement of major baseload resources. The reinforcement costs are included as a one-time charge based on the timing of the resource retirement.

Specifically, we have included the following proxy leave behind costs related to our baseload resource retirements as estimated from the MISO studies. We applied these costs in the modeling as soon as the resource is retired, over a three year period, to reflect the estimated local transmission reinforcement costs assumed to be required upon retirement. All numbers below are in real dollar terms ($2020).

- King: $48 million
- Sherco 3: $48 million
- Monticello: $96 million
- Prairie Island 1: $96 million
- Prairie Island 2: $96 million

K. Surplus Capacity Credit

The surplus capacity credit of up to 500 MW is applied for all twelve months of each year and is priced at the avoided capacity cost of a generic brownfield H-Class combustion turbine on an economic carrying charge basis.

Table 10: Surplus Capacity Credit

Surplus Capacity Credit

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
$/kw-mo	4.62	4.71	4.81	4.90	5.00	5.10	5.20	5.31	5.41	5.52	5.63	5.74	5.86	5.98	6.10	6.22	6.34	6.47	6.60	6.73

	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057
$/kw-mo	6.87	7.00	7.14	7.29	7.43	7.58	7.73	7.89	8.04	8.20	8.37	8.54	8.71	8.88	9.06	9.24	9.42	9.61	9.80	10.00

L. Effective Load Carrying Capability (ELCC) Capacity Credit for Wind, Solar, and Battery Resources

The ELCC for existing wind units is based on current MISO accreditation. The ELCC for generic wind is equal to 15.6% of their nameplate rating per MISO 2017/2018 Wind Capacity Report. The ELCC for generic solar is 50% of the AC nameplate capacity. The ELCC for a generic 4-hour battery is equal to 100% of their AC equivalent capacity.

M. Spinning Reserve Requirement

Spinning reserve is the on-line reserve capacity that is synchronized to the grid to maintain system frequency stability during contingency events and unforeseen load swings. The level of spinning reserve modeled is 137 MW and is based on a 12 month rolling average of spinning reserves carried by the NSP System within MISO.

N. Emergency Energy

Emergency energy is $500/MWh and is used to cover events where there are not enough resources available to meet system energy requirements.

O. Transmission Delivery Costs and Interconnection Costs

Transmission delivery costs for generic resources were developed by the Company. They are based on evaluation of recent and historical MISO studies and queue results. These costs represent "grid upgrades" to ensure deliverability of energy from these facilities to the overall bulk electric system.

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

Table 11: Transmission Delivery Costs

Transmission Delivery Costs				
	CC	CT	Wind	Solar
$/kw	500	200	400	140

P. Integration and Congestion Costs

Integration costs are taken from studies conducted by Enernex and apply to new wind and solar resources only. Congestion costs were developed by the Company using the MISO MTEP 2018 models and looking at the average congestion costs between representative wind bus locations and NSP.NSP. Congestion costs are applied to new wind projects only.

Table 12: Integration and Congestion Costs

Integration and Congestion Costs ($/MWh)				
Year	Integration		Congestion	
	Wind	Solar	Wind	Solar
2018	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00
2020	0.41	0.41	3.43	0.00
2021	0.42	0.42	3.50	0.00
2022	0.43	0.43	3.57	0.00
2023	0.44	0.44	3.64	0.00
2024	0.45	0.45	3.71	0.00
2025	0.46	0.46	3.79	0.00
2026	0.47	0.47	3.86	0.00
2027	0.48	0.48	3.94	0.00
2028	0.49	0.49	4.02	0.00
2029	0.49	0.49	4.10	0.00
2030	0.50	0.50	4.18	0.00
2031	0.51	0.51	4.27	0.00
2032	0.53	0.53	4.35	0.00
2033	0.54	0.54	4.44	0.00
2034	0.55	0.55	4.53	0.00
2035	0.56	0.56	4.62	0.00
2036	0.57	0.57	4.71	0.00
2037	0.58	0.58	4.80	0.00
2038	0.59	0.59	4.90	0.00
2039	0.60	0.60	5.00	0.00
2040	0.62	0.62	5.10	0.00
2041	0.63	0.63	5.20	0.00
2042	0.64	0.64	5.30	0.00
2043	0.65	0.65	5.41	0.00
2044	0.67	0.67	5.52	0.00
2045	0.68	0.68	5.63	0.00
2046	0.69	0.69	5.74	0.00
2047	0.71	0.71	5.86	0.00
2048	0.72	0.72	5.97	0.00
2049	0.74	0.74	6.09	0.00
2050	0.75	0.75	6.22	0.00
2051	0.77	0.77	6.34	0.00
2052	0.78	0.78	6.47	0.00
2053	0.80	0.80	6.60	0.00
2054	0.81	0.81	6.73	0.00
2055	0.83	0.83	6.86	0.00
2056	0.84	0.84	7.00	0.00
2057	0.86	0.86	7.14	0.00

Q. Distributed Generation and Community Solar Gardens

The distributed solar inputs are based on the most recent Company forecasts. Annual additions are modeled assuming a degradation of half a percent annually in generation, and a twenty five year service life. After a "vintage" of additions reach end of life, it is assumed 90% of the capacity is replaced at then-current costs. The Company expects a transition from Solar*Rewards to non-incentivized DG over time due to the end of statutory provisions.

Table 13: Distributed Solar Forecast

Distributed Solar (Nameplate MW)				
Year	Solar Rewards	Net Metered	Community Gardens	Total
2018	29	18	246	293
2019	41	27	504	573
2020	49	37	641	727
2021	53	47	649	749
2022	56	58	657	771
2023	57	70	665	792
2024	57	83	673	813
2025	56	96	681	834
2026	56	109	689	854
2027	56	122	697	875
2028	55	135	705	895
2029	55	147	713	915
2030	55	160	720	935
2031	55	172	728	955
2032	54	185	736	975
2033	54	197	744	995
2034	51	212	751	1,014
2035	45	229	759	1,033
2036	39	247	766	1,052
2037	34	262	774	1,070
2038	27	280	781	1,088
2039	16	301	789	1,106
2040	8	319	796	1,123
2041	4	333	804	1,141
2042	0	346	808	1,154
2043	0	358	796	1,154
2044	0	368	781	1,149
2045	0	379	776	1,155
2046	0	389	783	1,171
2047	0	399	789	1,188
2048	0	409	795	1,205
2049	0	419	802	1,221
2050	0	429	808	1,237
2051	0	439	814	1,254
2052	0	449	821	1,270
2053	0	459	827	1,286
2054	0	469	833	1,302
2055	0	479	839	1,318
2056	0	488	845	1,334
2057	0	498	852	1,350

R. Owned Unit Modeled Operating Characteristics and Costs

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

a. Retirement Date
b. Maximum Capacity
c. Current Unforced Capacity (UCAP) Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and particulate matter (PM)
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

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

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

a. Contract term
b. Maximum Capacity
c. Minimum Capacity Rating
d. Seasonal Deration
e. Heat Rate Profiles
f. Energy Schedule
g. Capacity Payments
h. Energy Payments
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

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

PPAs are modeled based upon their tested operating characteristics and contracted costs. Company owned units are modeled based upon their tested operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each renewable energy unit.

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

Wind hourly patterns are developed through a "Typical Wind Year" process where individual months are selected from the years 2014-2017 to develop a representative typical year. Actual generation data from the selected months is used to develop the profile for each wind farm. For farms where generation data is not complete or not available, data from nearby similar farms is used.

Solar hourly patterns are taken from the ELCC Study from Fall 2013 and updated to reflect the ELCC as stated above.

U. Generic Assumptions

Generic resources are modeled based upon their expected operating characteristics and projected costs. Generic thermal costs are developed by the Company. Generic battery costs are based on Public Service of Colorado All-Source Solicitation bids (Nov 28, 2017) with a 10% annual price improvement rate. Generic renewable costs and capacity factors are from National Renewable Energy Laboratory's 2018 Annual Technology Baseline data. Utility-scale wind and solar costs shown in Tables 16-18 include transmission costs from Table 10, while DG/distributed solar does not.

The Reference Case assumes "no going back" on renewables, meaning that we are committed to pursuing repowering and/or contract extension opportunities for renewable resources that will expire , and renewable resources are replaced "in-kind" when they reach end of life. Starting in 2023, generic solar is added to maintain at a minimum the 2015 IRP Preferred Plan solar levels. In 2023, there is approximately 1,800 GWhs of solar (both utility scale and DG solar) on the system which will grow to approximately 4,500 GWhs by 2028. The Company has already procured the levels of wind contemplated in the previous Resource Plan, so no minimum level of generic wind additions are needed. Additional renewables are included as Proview Alternatives.

In addition to base cost data for renewables, low and high costs are used for various sensitivities. Low and high wind and solar costs are based on the National Renewable Energy Laboratory's 2018 Annual Technology Baseline data. Low and high battery costs are based the percent difference in the NREL ATB low / high battery costs compared to the NREL ATB base costs, with this percent difference applied to the Company's base battery cost forecast. Below is a list of typical operating and cost inputs for each generic resource.

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 14: Thermal Generic Information (Costs in 2018 Dollars)

Thermal Generic Information					
Resource	**Sherco CC**	**Generic CC**	**Generic CT**	**Generic CT**	**Generic CT**
Technology	7H	7H	7H	7F	7H
Location Type	Brownfield	Greenfield	Brownfield	Brownfield	Greenfield
Cooling Type	Wet	Dry	Dry	Dry	Dry
Book life	40	40	40	40	40
Nameplate Capacity (MW)	835	901	374	232	374
Summer Peak Capacity (MW)	750	856	331	206	331
Capital Cost ($000) 2018$	$837,068	$906,588	$174,700	$114,766	$193,500
Electric Transmission Delivery ($000) 2018$	NA	$410,505	NA	NA	$74,804
Ongoing Capital Expenditures ($000-yr) 2018$	$6,200	$6,200	$1,784	$892	$1,784
Gas Demand ($000-yr) 2018$	$15,000	$19,058	$2,165	$1,342	$2,165
Gas Pipeline CIAC ($000) 2018 $	$192,000	NA	NA	NA	NA
Capital Cost ($/kW) 2018$	$1,002	$1,006	$467	$495	$517
Electric Transmission Delivery ($/kW) 2018$	NA	$455	NA	NA	$200
Ongoing Capital Expenditures ($/kW-yr) 2018$	$7.42	$6.88	$4.77	$3.85	$4.77
Gas Demand ($/kW-yr) 2018$	$17.96	$21.14	$5.79	$5.79	$5.79
Fixed O&M Cost ($000/yr) 2018$	$6,592	$6,592	$1,253	$1,203	$1,253
Variable O&M Cost ($/MWh) 2018$	$1.04	$1.04	$0.99	$1.03	$0.99
Levelized $/kw-mo (All Fixed Costs) $2018	$14.46	$16.19	$5.96	$6.27	$8.14
Summer Heat Rate 100% Loading (btu/kWh)	6,359	6,848	9,264	10,025	9,264
Summer Heat Rate 75% Loading (btu/kWh)	6,547	6,874	9,738	10,581	9,738
Summer Heat Rate 50% Loading (btu/kWh)	6,985	7,334	11,120	12,515	11,120
Summer Heat Rate 25% Loading (btu/kWh)	8,004	8,404	11,558	13,430	11,558
Forced Outage Rate	3%	3%	3%	3%	3%
Maintenance (weeks/yr)	5	5	2	2	2
CO2 Emissions (lbs/MMBtu)	118	118	118	118	118
SO2 Emissions (lbs/MWh)	0.00	0.00	0.00	0.00	0.00
NOx Emissions (lbs/MWh)	0.05	0.05	0.90	0.32	0.90
PM10 Emissions (lbs/MWh)	0.02	0.02	0.03	0.03	0.03
Mercury Emissions (lbs/MMWh)	0.00	0.00	0.00	0.00	0.00

Table 15: Renewable Generic Information (Costs in 2018 Dollars)

Renewable Generic Information				
Resource	**Wind**	**Utility Scale Solar**	**Distributed Solar Commercial**	**Distributed Solar Residential**
ELCC Capacity Credit (%)	15.6%	50.0%	50.0%	50.0%
Capacity Factor	50.0%	17.7%	14.0%	14.8%
Book life	25	25	25	25
Electric Transmission Delivery ($/kW)	400	140	0	0

Table 16: Storage Generic Information (Costs in 2018 Dollars)

Storage Generic Information	
Resource	**Battery**
Technology	Li Ion
Location Type	NA
Book life	40
Nameplate Capacity (MW)	321
Summer Peak Capacity (MW)	321
Storage Volume (hrs)	4
Cycle Efficiency (%)	88
Equivalent Full Cycles per Year	156
Electric Transmission Delivery ($000) 2018$	0
Levelized $/kw-mo (All Fixed Costs) $2023	$10.53

Table 17: Levelized Capacity Costs by In-Service Year

Levelized Capacity Costs by In-Service Year ($/kw-mo)								
COD	CT - 7H Greenfield	CT - 7F Brownfield	CT - 7H Brownfield	CC	Sherco CC	Base Battery	Low Battery	High Battery
2018	$8.14	$6.27	$5.96	$16.19	$14.46			
2019	$8.31	$6.40	$6.08	$16.51	$14.75			
2020	$8.47	$6.53	$6.20	$16.84	$15.04			
2021	$8.64	$6.66	$6.33	$17.18	$15.35			
2022	$8.81	$6.79	$6.46	$17.52	$15.65			
2023	$8.99	$6.93	$6.58	$17.88	$15.97	$10.53	$8.03	$13.71
2024	$9.17	$7.07	$6.72	$18.23	$16.28	$9.48	$6.99	$12.51
2025	$9.35	$7.21	$6.85	$18.60	$16.61	$8.91	$6.35	$11.92
2026	$9.54	$7.35	$6.99	$18.97	$16.94	$8.53	$5.90	$11.41
2027	$9.73	$7.50	$7.13	$19.35	$17.28	$8.24	$5.53	$11.04
2028	$9.93	$7.65	$7.27	$19.74	$17.63	$8.02	$5.20	$10.73
2029	$10.13	$7.80	$7.41	$20.13	$17.98	$7.83	$4.92	$10.49
2030	$10.33	$7.96	$7.56	$20.53	$18.34	$7.68	$4.65	$10.28
2031	$10.53	$8.12	$7.71	$20.94	$18.71	$7.54	$4.51	$10.19
2032	$10.75	$8.28	$7.87	$21.36	$19.08	$7.42	$4.39	$10.13
2033	$10.96	$8.44	$8.03	$21.79	$19.46	$7.31	$4.27	$10.08
2034	$11.18	$8.61	$8.19	$22.23	$19.85	$7.22	$4.16	$10.05
2035	$11.40	$8.79	$8.35	$22.67	$20.25	$7.13	$4.05	$10.02
2036	$11.63	$8.96	$8.52	$23.12	$20.65	$7.05	$3.94	$10.02
2037	$11.86	$9.14	$8.69	$23.59	$21.07	$6.98	$3.83	$10.03
2038	$12.10	$9.32	$8.86	$24.06	$21.49	$6.91	$3.73	$10.05
2039	$12.34	$9.51	$9.04	$24.54	$21.92	$6.85	$3.63	$10.07
2040	$12.59	$9.70	$9.22	$25.03	$22.36	$6.79	$3.53	$10.09
2041	$12.84	$9.89	$9.40	$25.53	$22.80	$6.73	$3.44	$10.11
2042	$13.10	$10.09	$9.59	$26.04	$23.26	$6.68	$3.36	$10.13
2043	$13.36	$10.29	$9.78	$26.56	$23.72	$6.63	$3.28	$10.15
2044	$13.63	$10.50	$9.98	$27.09	$24.20	$6.58	$3.20	$10.17
2045	$13.90	$10.71	$10.18	$27.63	$24.68	$6.54	$3.12	$10.20
2046	$14.18	$10.92	$10.38	$28.19	$25.18	$6.50	$3.10	$10.13
2047	$14.46	$11.14	$10.59	$28.75	$25.68	$6.46	$3.09	$10.07
2048	$14.75	$11.37	$10.80	$29.33	$26.19	$6.42	$3.07	$10.01
2049	$15.05	$11.59	$11.02	$29.91	$26.72	$6.38	$3.06	$9.96
2050	$15.35	$11.82	$11.24	$30.51	$27.25	$6.35	$3.04	$9.91
2051	$15.65	$12.06	$11.46	$31.12	$27.80	$6.31	$3.03	$9.85
2052	$15.97	$12.30	$11.69	$31.74	$28.35	$6.28	$3.01	$9.80
2053	$16.29	$12.55	$11.93	$32.38	$28.92	$6.25	$3.00	$9.76
2054	$16.61	$12.80	$12.16	$33.03	$29.50	$6.22	$2.98	$9.71
2055	$16.94	$13.06	$12.41	$33.69	$30.09	$6.19	$2.97	$9.66
2056	$17.28	$13.32	$12.66	$34.36	$30.69	$6.16	$2.95	$9.62
2057	$17.63	$13.58	$12.91	$35.05	$31.30	$6.13	$2.94	$9.58

Table 18: Base Renewable Levelized Costs by In-Service Year

Levelized Costs by In-Service Year $/MWh (LCOE)				
COD	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$29.79	$40.00	$73.92	$97.93
2021	$29.65	$40.00	$71.77	$91.35
2022	$34.04	$40.00	$70.71	$88.46
2023	$38.61	$49.48	$69.59	$87.04
2024	$43.39	$49.90	$68.41	$85.55
2025	$52.15	$50.32	$67.18	$83.98
2026	$52.55	$50.74	$65.88	$82.34
2027	$52.98	$51.17	$64.53	$80.63
2028	$53.42	$51.59	$63.11	$78.83
2029	$53.89	$52.01	$61.62	$76.95
2030	$54.39	$52.43	$60.07	$74.98
2031	$54.95	$53.10	$60.66	$75.15
2032	$55.54	$53.78	$61.25	$75.28
2033	$56.16	$54.47	$61.84	$75.40
2034	$56.80	$55.16	$62.43	$75.49
2035	$57.47	$55.86	$63.02	$75.56
2036	$58.17	$56.57	$63.61	$75.60
2037	$58.91	$57.28	$64.20	$75.61
2038	$59.67	$58.00	$64.78	$75.60
2039	$60.47	$58.72	$65.37	$75.56
2040	$61.30	$59.45	$65.95	$75.49
2041	$62.17	$60.13	$66.88	$76.33
2042	$63.07	$60.81	$67.82	$77.18
2043	$64.01	$61.50	$68.77	$78.04
2044	$64.99	$62.18	$69.74	$78.89
2045	$66.01	$62.87	$70.71	$79.76
2046	$67.07	$63.57	$71.70	$80.62
2047	$68.17	$64.27	$72.70	$81.49
2048	$69.32	$64.97	$73.71	$82.36
2049	$70.52	$65.68	$74.73	$83.24
2050	$71.76	$66.38	$75.76	$84.07
2051	$73.20	$67.71	$77.28	$85.75
2052	$74.66	$69.07	$78.83	$87.47
2053	$76.16	$70.45	$80.40	$89.22
2054	$77.68	$71.86	$82.01	$91.00
2055	$79.23	$73.29	$83.65	$92.82
2056	$80.82	$74.76	$85.32	$94.68
2057	$82.43	$76.25	$87.03	$96.57

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

Table 19: Low Renewable Levelized Costs by In-Service Year

Low Levelized Costs by In-Service Year $/MWh (LCOE)				
COD	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$25.51	$35.18	$56.57	$94.61
2021	$24.43	$35.18	$51.50	$85.46
2022	$27.80	$35.18	$50.18	$81.18
2023	$31.28	$43.52	$48.81	$78.32
2024	$34.89	$43.21	$47.40	$75.38
2025	$42.41	$42.88	$45.95	$72.34
2026	$41.50	$42.54	$44.44	$69.21
2027	$40.53	$42.17	$42.89	$65.98
2028	$39.52	$41.79	$41.28	$62.65
2029	$38.00	$41.39	$39.63	$59.22
2030	$37.80	$40.97	$37.93	$55.69
2031	$37.66	$41.28	$37.65	$53.91
2032	$38.06	$41.58	$37.35	$52.04
2033	$38.48	$41.88	$37.03	$50.07
2034	$38.90	$42.28	$36.68	$48.02
2035	$39.34	$42.25	$36.30	$45.87
2036	$39.80	$42.39	$35.90	$43.62
2037	$40.26	$42.52	$35.47	$41.27
2038	$40.75	$42.64	$35.01	$38.81
2039	$41.24	$42.75	$34.52	$36.25
2040	$41.75	$42.85	$33.99	$33.57
2041	$42.27	$43.27	$34.47	$34.11
2042	$42.80	$43.39	$34.95	$34.64
2043	$43.35	$43.37	$35.44	$35.19
2044	$43.92	$43.33	$35.94	$35.75
2045	$44.50	$44.15	$36.44	$36.31
2046	$45.09	$43.34	$36.95	$36.88
2047	$45.70	$43.39	$37.46	$37.46
2048	$46.32	$43.42	$37.98	$38.05
2049	$46.96	$43.44	$38.50	$38.65
2050	$47.62	$43.97	$39.04	$39.22
2051	$48.57	$44.85	$39.82	$40.00
2052	$49.54	$45.74	$40.61	$40.80
2053	$50.53	$46.66	$41.43	$41.62
2054	$51.54	$47.59	$42.25	$42.45
2055	$52.57	$48.54	$43.10	$43.30
2056	$53.63	$49.51	$43.96	$44.17
2057	$54.70	$50.50	$44.84	$45.05

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

Table 20: High Renewable Levelized Costs by In-Service Year

High Levelized Costs by In-Service Year $/MWh (LCOE)				
COD	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$34.70	$50.52	$88.96	$124.70
2021	$35.40	$50.52	$91.58	$127.20
2022	$40.61	$50.52	$93.41	$128.14
2023	$46.03	$62.48	$95.28	$130.70
2024	$51.64	$63.73	$97.19	$133.32
2025	$61.25	$65.01	$99.13	$135.98
2026	$62.49	$66.31	$101.11	$138.70
2027	$63.76	$67.63	$103.14	$141.48
2028	$65.06	$68.99	$105.20	$144.30
2029	$66.38	$70.37	$107.30	$147.19
2030	$67.72	$71.77	$109.45	$150.13
2031	$69.10	$73.21	$111.64	$153.14
2032	$70.50	$74.67	$113.87	$156.20
2033	$71.93	$76.17	$116.15	$159.32
2034	$73.39	$77.69	$118.47	$162.51
2035	$74.88	$79.24	$120.84	$165.76
2036	$76.39	$80.83	$123.26	$169.08
2037	$77.94	$82.45	$125.72	$172.46
2038	$79.52	$84.09	$128.24	$175.91
2039	$81.13	$85.78	$130.80	$179.42
2040	$82.77	$87.49	$133.42	$183.01
2041	$84.45	$89.24	$136.09	$186.67
2042	$86.16	$91.03	$138.81	$190.41
2043	$87.90	$92.85	$141.58	$194.21
2044	$89.68	$94.70	$144.42	$198.10
2045	$91.49	$96.60	$147.30	$202.06
2046	$93.34	$98.53	$150.25	$206.10
2047	$95.23	$100.50	$153.25	$210.22
2048	$97.15	$102.51	$156.32	$214.43
2049	$99.12	$104.56	$159.45	$218.72
2050	$101.12	$106.65	$162.63	$223.09
2051	$103.14	$108.79	$165.89	$227.55
2052	$105.21	$110.96	$169.21	$232.10
2053	$107.31	$113.18	$172.59	$236.75
2054	$109.46	$115.44	$176.04	$241.48
2055	$111.65	$117.75	$179.56	$246.31
2056	$113.88	$120.11	$183.15	$251.24
2057	$116.16	$122.51	$186.82	$256.26

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

ATTACHMENT A: HEAT RATE UPDATED

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

Heat rate data for the Company's owned generating units is provided publicly in our annual Federal Energy Regulatory Commission (FERC) Financial Report, FERC Form No. 1. We include a copy of the pertinent unit heat rate data from FERC Form No. 1 for 2018 in Table 21 below.

Table 21: 2018 FERC Heat Rates

Unit	Heat Rate
AS King	10,013
Sherco	10,546
Monticello	10,505
Prairie Island	10,487
Black Dog (NG)	7,870
High Bridge	6,863
Riverside	7,172
French Island	23,570
Wilmarth	10,637

The Company's Performance Monitoring department performs routine heat rate testing and conducts heat balances of its generating units. In addition, testing, assessments, and reporting on boilers, air heaters, cooling towers, and enthalpy drop tests on steam turbines are also conducted. These tools factor into our assessment of the condition of these individual components, as well as how their respective performance levels will impact the overall efficiency of a given generating unit. Table 22 below shows a summary of NSP System heat rate testing from 2015-2018.

Table 22: Heat Rate Tests – 2015-2018

Plant/Unit	Type of Unit Test	Type of Test	Year Tested
Sherco U1	Coal Boiler	Heat Rate	2015
Bayfront U4	Combustion Turbine	Calculated Adjustment for Fuel Change	2016
King U1	Coal Boiler	Heat Rate	2016
Sherco U2	Coal Boiler	Heat Rate	2015, 2016
Black Dog U5/U2	Combined Cycle	Heat Rate	2015, 2017
High Bridge CC	Combined Cycle	Heat Rate	2017, 2018
Sherco U3	Coal Boiler	Heat Rate	2017
Black Dog U6	Combustion Turbine	Heat Rate	2018
Riverside U7,U9,U10	Combined Cycle	Heat Rate	2017,2018

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

ATTACHMENT B: WATER AND PLANT OPERATIONS

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

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

The Clean Water Act Section 316(a) sets thermal limitations for discharges and the criteria and processes for allowing thermal variances. The Company's power plant discharge temperature limits and allowances for thermal emergency provisions are outlined in the plants' National Pollutant Discharge Elimination System (NPDES) permits. Additionally, Xcel Energy has policies which outline the conditions and procedures to implement during periods of energy emergencies that allow for limited thermal variances.

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

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

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

ATTACHMENT C: ICAP LOAD AND RESOURCES TABLE

The following table shows load and resources using Installed Capacity Rating (ICAP) for the planning period, in compliance with the Minnesota Commission's August 5, 2013 Notice of Information in Future Resource Plan Filings.[1]

Table 23: Load and Resources Tables, 2020-2034 Planning Period

ICAP Rating - Load and Resources 2020-2034 Planning Period

Determination of Need	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Forecast Load	9,112	9,087	9,103	9,075	9,048	8,998	8,965	8,963	9,014	9,016	9,042	9,052	9,166	9,295	9,301
MISO System Coincident (ICAP)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Coincident Load	9,112	9,087	9,103	9,075	9,048	8,998	8,965	8,963	9,014	9,016	9,042	9,052	9,166	9,295	9,301
MISO Planning Reserve	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%
Obligation	10,670	10,641	10,660	10,627	10,595	10,537	10,498	10,495	10,556	10,558	10,589	10,599	10,733	10,885	10,892

Existing and Approved Resources	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Load Management, Existing	940	955	970	989	1,007	1,023	1,038	1,053	1,066	1,054	1,043	1,032	1,021	1,010	1,000
Load Management, Potential Study	270	290	312	322	339	380	392	406	421	438	456	476	497	527	550
Coal	2,471	2,471	2,471	2,471	1,773	1,773	1,773	1,062	1,062	1,062	1,062	1,062	1,062	1,062	1,062
Nuclear	1,697	1,697	1,697	1,697	1,697	1,697	1,697	1,697	1,697	1,697	1,697	1,053	1,053	1,053	527
Natural Gas/Oil	3,511	3,511	3,511	3,511	3,347	3,032	2,784	2,260	2,139	2,139	2,139	2,139	1,858	1,858	1,858
MEC	720	720	720	720	720	720	720	720	720	720	720	720	720	720	720
Sherco CC	0	0	0	0	0	0	0	786	786	786	786	786	786	786	786
Biomass/RDF	107	107	107	84	84	60	60	60	19	19	19	19	19	19	19
Hydro	887	1,009	1,002	1,002	1,002	152	152	152	152	152	152	152	145	142	142
Wind	3,954	4,200	4,200	4,054	4,054	4,034	4,012	3,913	3,848	3,739	3,735	3,439	3,372	2,984	2,620
Distributed Solar	42	48	55	60	66	72	78	83	89	95	100	105	111	116	121
Solar*Rewards Community	335	339	344	348	352	356	360	365	369	373	377	381	385	389	393
Grid Scale Solar	182	182	181	180	179	178	177	176	175	174	174	173	172	171	170
Existing Resources	15,117	15,530	15,569	15,438	14,620	13,477	13,243	12,732	12,543	12,448	12,460	11,536	11,200	10,837	9,968

Existing and Approved Net Resource (Need)/Surplus	4,446	4,889	4,909	4,811	4,025	2,941	2,745	2,237	1,987	1,890	1,871	937	466	-48	-924

Reference Plan Resource Additions/Retirements	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Natural Gas/Oil	0	0	0	0	0	0	0	0	0	0	0	0	220	570	920
Wind	0	0	0	126	171	242	307	379	389	496	512	568	598	1,122	2,702
Solar	0	0	0	0	0	251	251	752	1,002	1,252	1,253	1,753	2,004	2,004	2,004
Reference Plan Resource Adjustments	0	0	0	126	172	492	558	1,131	1,391	1,749	1,765	2,321	2,822	3,696	5,627

Reference Plan Net Resource (Need)/Surplus	4,446	4,889	4,909	4,937	4,197	3,433	3,303	3,367	3,379	3,639	3,636	3,258	3,288	3,647	4,702

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

APPENDIX F3 - SCENARIO SENSITIVITY ANALYSIS: PVRR & PVSC SUMMARY

		A	B	C	D	E	F	G	I	J	K	L	M	N	ECF	DBF
	PVSC	PVRR	Low Gas/Coal/ Mkts	High Gas/Coal/ Mkts	Low Load	High Load	Low Resource Cost	High Resource Cost	Low Externality	Low Externality, Low Regulatory	Mid Externality, Mid Regulatory	High Externality	No Reg or Externality Costs	Market sales off	High Load High Gas/Coal/Mkts Low Resource Cost	Low Load Low Gas/Coal/Mkts Low Resource Cost
1- REFERENCE	$45,657	$37,679	$45,216	$46,360	$46,328	$49,952	$44,760	$46,813	$40,949	$39,008	$42,541	$52,890	$37,276	$45,260	$49,797	$45,359
2- EARLY KING	$45,450	$37,495	$44,909	$46,347	$46,258	$49,795	$44,703	$46,499	$40,570	$38,811	$42,319	$52,001	$37,064	$44,896	$49,787	$45,276
3- EARLY SH3	$45,563	$37,662	$45,018	$46,420	$46,373	$49,940	$44,828	$46,593	$40,643	$38,975	$42,418	$51,868	$37,235	$44,993	$49,935	$45,396
4- EARLY COAL	$45,449	$37,632	$44,882	$46,394	$46,274	$49,777	$44,758	$46,475	$40,435	$38,934	$42,324	$51,128	$37,202	$44,859	$49,968	$45,311
5- EARLY MONTI	$45,824	$37,782	$45,347	$46,570	$46,498	$50,093	$44,907	$47,034	$41,021	$39,111	$42,673	$52,931	$37,356	$45,325	$49,953	$45,470
6- EARLY PI	$46,345	$38,281	$45,847	$47,119	$46,892	$50,741	$45,222	$47,704	$41,558	$39,584	$43,177	$53,636	$37,847	$45,739	$50,392	$45,715
7- EARLY All NUCLEAR	$46,491	$38,292	$45,956	$47,306	$47,000	$50,782	$45,329	$47,873	$41,586	$39,620	$43,267	$53,725	$37,857	$45,840	$50,503	$45,768
8- EARLY BASELOAD	$46,251	$38,144	$45,561	$47,366	$46,985	$50,646	$45,341	$47,462	$41,006	$39,488	$43,002	$51,915	$37,710	$45,306	$50,747	$45,734
9- EARLY COAL; EXTEND MONTI	$45,173	$37,476	$44,705	$45,966	$46,084	$49,419	$44,628	$46,065	$40,250	$38,757	$42,098	$50,829	$37,050	$44,646	$49,701	$45,327
10- EARLY KING; EXTEND MONTI	$45,124	$37,286	$44,684	$45,877	$46,010	$49,444	$44,552	$46,054	$40,322	$38,590	$42,044	$51,601	$36,860	$44,628	$49,601	$45,258
11- EARLY COAL; EXTEND PI	$44,788	$37,134	$44,395	$45,449	$45,711	$49,020	$44,327	$45,595	$39,885	$38,406	$41,731	$50,394	$36,705	$44,239	$49,551	$45,100
12- EARLY COAL; EXTEND All NUCLEAR	$44,655	$37,240	$44,460	$45,018	$45,589	$48,794	$44,194	$45,462	$39,977	$38,455	$41,696	$50,435	$36,813	$44,356	$49,324	$45,177
13- EXTEND MONTI	$45,268	$37,316	$44,833	$45,978	$46,130	$49,577	$44,690	$46,181	$40,516	$38,635	$42,156	$52,315	$36,884	$44,720	$49,665	$45,394
14- EXTEND PI	$44,830	$36,906	$44,440	$45,455	$45,757	$49,158	$44,379	$45,618	$40,080	$38,219	$41,729	$51,800	$36,471	$44,266	$49,382	$45,157
15- EXTEND All NUCLEAR	$44,749	$37,065	$44,541	$45,116	$45,678	$48,852	$44,316	$45,508	$40,209	$38,333	$41,744	$51,812	$36,636	$44,394	$49,255	$45,281
REFERENCE ADJ (ADD DR)	$45,974	$38,055	$45,534	$46,677	$46,679	$50,276	$45,077	$47,131	$41,267	$39,327	$42,859	$53,204	$37,595	$45,579	$50,121	$45,711
PREFERRED PLAN	$45,513	$37,851	$45,046	$46,307	$46,416	$49,757	$44,969	$46,405	$40,591	$39,099	$42,439	$51,168	$37,392	$44,990	$50,040	$45,660
ND PLAN	$45,892	$37,598	$44,869	$45,901	$46,833	$50,123	$45,231	$46,904	$40,415	$38,892	$42,208	$51,021	$37,208	$44,817	$49,443	$45,356

		A	B	C	D	E	F	G	I	J	K	L	M	N	ECF	DBF
DELTAS	PVSC	PVRR	Low Gas/Coal/ Mkts	High Gas/Coal/ Mkts	Low Load	High Load	Low Resource Cost	High Resource Cost	Low Externality	Low Externality, Low Regulatory	Mid Externality, Mid Regulatory	High Externality	No Reg or Externality Costs	Market sales off	High Load High Gas/Coal/Mkts Low Resource Cost	Low Load Low Gas/Coal/Mkts Low Resource Cost
1- REFERENCE	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
2- EARLY KING	($207)	($184)	($307)	($12)	($71)	($156)	($56)	($315)	($379)	($197)	($222)	($889)	($213)	($365)	($10)	($83)
3- EARLY SH3	($93)	($17)	($198)	$60	$45	($12)	$69	($220)	($306)	($33)	($124)	($1,022)	($41)	($267)	$137	$37
4- EARLY COAL	($208)	($47)	($334)	$35	($54)	($174)	($1)	($339)	($513)	($74)	($217)	($1,762)	($75)	($401)	$170	($48)
5- EARLY MONTI	$167	$103	$131	$210	$170	$142	$147	$220	$72	$103	$131	$42	$80	$65	$156	$111
6- EARLY PI	$689	$602	$631	$759	$564	$789	$462	$891	$609	$576	$636	$746	$571	$479	$595	$356
7- EARLY All NUCLEAR	$834	$613	$740	$947	$672	$831	$569	$1,060	$637	$612	$726	$835	$581	$580	$706	$409
8- EARLY BASELOAD	$594	$465	$345	$1,006	$656	$695	$582	$649	$57	$480	$460	($975)	$433	$46	$950	$375
9- EARLY COAL; EXTEND MONTI	($484)	($204)	($510)	($394)	($245)	($533)	($131)	($748)	($699)	($251)	($443)	($2,060)	($226)	($614)	($96)	($32)
10- EARLY KING; EXTEND MONTI	($532)	($393)	($532)	($482)	($318)	($508)	($207)	($759)	($626)	($418)	($498)	($1,288)	($416)	($632)	($197)	($101)
11- EARLY COAL; EXTEND PI	($868)	($545)	($821)	($911)	($617)	($931)	($433)	($1,218)	($1,064)	($602)	($811)	($2,496)	($571)	($1,022)	($247)	($259)
12- EARLY COAL; EXTEND All NUCLEAR	($1,001)	($439)	($756)	($1,342)	($740)	($1,158)	($566)	($1,352)	($972)	($553)	($846)	($2,455)	($463)	($904)	($473)	($182)
13- EXTEND MONTI	($388)	($363)	($383)	($381)	($198)	($375)	($70)	($632)	($433)	($373)	($386)	($575)	($393)	($540)	($133)	$34
14- EXTEND PI	($827)	($773)	($776)	($905)	($571)	($794)	($381)	($1,195)	($868)	($789)	($813)	($1,090)	($805)	($995)	($416)	($202)
15- EXTEND All NUCLEAR	($908)	($614)	($675)	($1,244)	($650)	($1,099)	($444)	($1,305)	($739)	($675)	($797)	($1,078)	($640)	($867)	($542)	($79)
REFERENCE ADJ (ADD DR)	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
PREFERRED PLAN	($461)	($203)	($488)	($371)	($263)	($519)	($109)	($726)	($675)	($228)	($420)	($2,037)	($203)	($588)	($81)	($51)
ND PLAN	($83)	($456)	($665)	($777)	$154	($153)	$154	($227)	($852)	($435)	($652)	($2,184)	($388)	($761)	($678)	($355)

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Public Service Commission | **Case No. PU-18-403**
Northern States Power Company
Acquisition of the 375 MW Mankato Energy Center and the 345 MW Mankato Energy Center II

AFFIDAVIT OF SERVICE

STATE OF MINNESOTA)
)ss
COUNTY OF HENNEPIN)

Lynnette Sweet states under oath as follows:

1. I swear and affirm upon penalty of perjury that the statements made in this affidavit are true and correct.

2. I am of legal age and on the 30th day of July 2019, I served the attached:

Late-Filed Exh. 1. Additional Comparable Transactions

Late-Filed Exh. 2. Remaining Lives of NSP's Fleet

Late-Filed Exh. 3. Citations and Excerpts from NSP's Upper Midwest Resource Plan

upon the following, by sending via Federal Express true and correct copies to:

Patrick J. Ward, Administrative Law Judge Zuger Kirmis & Smith 316 North 5th Street Bismarck, ND 58501	Zachary Pelham Attorney at Law 314 E. Thayer Avenue, 3rd Floor Bismarck, ND 58501
Mitchell D. Armstrong Smith Porsborg Schweigert Armstrong Moldenhauer & Smith 122 East Broadway Avenue Bismarck, ND 58503	Jack Schuh North Dakota Public Service Commission Special Assistant Attorney General Department 408 600 East Boulevard Avenue Bismarck, ND 58505-0480

Lynnette Sweet

Subscribed and sworn before me this 30th day of July, 2019.

James G. Erickson
Notary Public
Minnesota
My Commission Expires January 31, 2024

Notary Public
Hennepin County, Minnesota