PUB/DAYMARK - 9 Reference: Daymark Export Revenue Report Page 39

a) Please confirm whether the four natural gas forecasts are all referenced to the same market hub or whether adjustments were required. If adjustments were required, please provide Daymark's views as to whether those adjustments were appropriate and justified.

b) Please identify whether the prices in Figure 16 are real or nominal dollars, the currency, and the units.

Response:

a) All four forecasts are referenced to Henry Hub. The only adjustments made by MH to these values was to put all values in the same year dollars. That adjustment is appropriate. The chart source is a Confidential workpaper provided by MH to Daymark (Spreadsheet name: 2017 Energy Price Forecast V3.xlsx)

b) The values are real, 2017 US dollars/MMBtu.

COMMERCIALLY SENSITIVE INFORMATION

PUB/DAYMARK - 11 Reference: Daymark Export Revenue Report Page 47

Please explain whether Daymark finds Manitoba Hydro's adjustment of the forecasters' Minn Hub prices to the MHEB hub to be appropriate.

Response:

MH's methods in the 2016 Electricity Export Price Forecast (2016 EEPF) (Appendix D, page 40) uses [redacted] We find this to be a reasonable approach for planning, given that is a complex process to forecast the dynamics of congestion and losses in a forecasting model. The resulting adjustments are not significantly different from and [redacted] than the assumptions used in prior EEPFs. 3a 3b

PUB/DAYMARK - 12 Reference: Daymark Export Revenue Report Page 55

Please re-plot Figure 27 with all three series in stacked columns, with firm (contract) sales as the "bottom" series of the graph, followed by surplus dependable energy and then opportunity energy at the top of each column.

Response:

See CONFIDENTIAL graph below:

[redacted]

5b, 5c

PUB/DAYMARK - 1 Reference: Daymark Export Revenue Report Page 13 Figure 4

Please confirm whether the unit types set the locational market price at the Minn Hub or MHEB pricing node in the same proportion shown in Figure 4. If not confirmed, please identify the share of intervals set by each unit type for Minn Hub or MHEB hub. If this information is not available, please explain the factors that would result in a different mix of unit types setting the price at the Minn Hub or MHEB hub.

Response:

Not confirmed.

The data depicted in Figure 4 is information contained in the 2016 State of the Market Report for the MISO Electricity Market (2016 SOMR) (See footnote 18 of the Daymark report). This information is not specific to the Minn Hub and the 2016 SOMR does not contain this information specific to the Minn Hub.

The locational market prices and the resources that set those prices will differ from the MISO market, in the aggregate, when congestion exists between Minnesota and other portions of the MISO market or when loss factors cause local resources to be economic relative to sources on the margin in other regions.

PUB/DAYMARK - 2 Reference: Daymark Export Revenue Report Page 22

a) Please explain whether Minnesota Power identified the generation sources that it intends to add to its generation portfolio in order to meet its 44% renewable generation target by 2025.

b) Please show the current mix of Minnesota Power's generation sources by unit or fuel type in order to show how much additional renewable generation is needed to meet the 44% target.

c) Considering Manitoba Hydro's existing 250MW power sale agreement with Minnesota Power along with its existing mix of non-dispatchable renewable generation, please give Daymark's view whether Minnesota Power is in a position to add more non-dispatchable renewable generation or whether it is approaching the limit of non-dispatchable generation in its system.

Response:

a) Minnesota Power's June 7, 2017 news release cited in the Daymark report states:

> *In an upcoming filing with the Minnesota Public Utilities Commission (MPUC), Minnesota Power will request the addition of 250 megawatts of wind power capacity, an additional 10 megawatts of solar power and 250 megawatts of combined-cycle natural gas generation to meet customer demand for power, which is projected to grow throughout the region. The new resources will increase the company's already robust wind portfolio of 620 megawatts and double its solar generation.*

and:

> *With approval of the proposed resource package by the MPUC, renewable energy resources— including wind, Canadian hydro, solar and biomass—will account for 44 percent of the utility's energy supply portfolio, exceeding the initial Energy**Forward** goal of one-third renewable power. Minnesota Power's long-term*

> *goal is an energy mix of two-thirds renewable energy and flexible, renewable-enabling natural gas and one-third environmentally compliant baseload coal.*

b) Please refer to response to part a.

c) Minnesota Power's 2015 Integrated Resource Plan (September 1, 2015, page 32) offers the following statement regarding renewable resource integration:

> *The regional market allows the Company to maximize its generation and transactions. In particular, the market provides timely and cost-effective flexibility to help support the integration of additional renewable energy into Minnesota Power's system. The maturity and flexibility within the regional energy market allows the Company to buy and sell electricity to manage supply and demand for the topmost portion of its load at the lowest possible cost.*

PUB/DAYMARK - 3 Reference: Daymark Export Revenue Report Page 23

a) To the extent that the information is provided in Northern States Power's Integrated Resource Plan (IRP), please indicate whether Northern States Power is in a position to replace its 375MW/325MW contract with Manitoba Hydro with dispatachable generation (such as combustion turbines) and still meet its Renewable Portfolio Standard obligations. Please cite the IRP if possible.

b) To the extent that the information is provided in Northern States Power's Integrated Resource Plan (IRP), please indicate whether Northern States Power is in a position to add more non-dispatchable renewable generation or whether it is approaching the limit of non-dispatchable generation in its system. Please cite the IRP if possible.

Response:

a) On Page 23, Daymark reports certain information obtained from the most recently public documents regarding Northern States Power's (NSP) integrated resource plan. NSPs indicates that it is already on track to meet its Renewable Energy Standard requirements through the planning period and plans to add significantly more renewable energy than is required to meet the RES requirements. (See PUB/Daymark-3 Attachment 1 at page 12). NSP's five-year action plan includes the following statement (See PUB/Daymark-3 Attachment 2 at page 59):

> *Hydro. We will continue to evaluate the potential and value of hydro resource options including the potential for hydro resources from Manitoba Hydro beyond the current contracts that expire in the mid-2020s.*

The Minnesota Public Utilities Commission (MPUC) includes the following modification in its January 2017 order approving the NSP IRP (See PUB/Daymark-3 Attachment 3 at page 11):

> *Xcel's resource plan is modified … to change Xcel's planned CT additions in the 2025-2030 timeframe to provide instead for adding the most cost-effective combination of resources consistent with state energy policies, including but not limited to the following resource options: large hydropower, short-term life extensions of Xcel-owned peaking units, natural gas combustion turbines, demand response, utility-scale solar generation, energy storage, and combined heat and power.*

Based on the foregoing public statements of NSP and the MPUC, Daymark understands that NSP could, at the conclusion of the current contracts with MH, secure replacement power from dispatchable generation such as combustion turbines and comply with RES requirements.

b) NSP's IRP included a wind integration study to conclude that the system could support the wind energy additions proposed in the IRP (See PUB/Daymark-3 Attachment 1 at page 91). It also indicates that the integration of increased renewable energy and DG on its system will require significant investments in its transmission system (Id. at page 37).

PUB/DAYMARK - 4 Reference: Daymark Export Revenue Report Pages 22 to 24

Please confirm whether Manitoba Hydro's exports meet the requirements of Minnesota's and Wisconsin's Renewable Portfolio Standards, or whether there are limitations or exclusions on these exports such that they are not counted towards meeting the RPS.

Response:

Not confirmed. The renewable energy policies in Minnesota (Renewable Energy Standard) and Wisconsin (Renewable Portfolio Standard) regarding the eligibility of hydropower includes size limits (100 MW and 60 MW, respectively).

PUB/DAYMARK - 5 Reference: Daymark Export Revenue Report Page 27

Does MISO have a forward capacity market that extends beyond the next year? If so, please explain how this market operates

Response:

No. Forward transactions in years after the current forward year are exclusively bilateral transactions among market participants. Bilateral transactions are subject to state and federal regulations, however, MISO does not administer any market for such transactions.

PUB/DAYMARK - 6 Reference: Daymark Export Revenue Report Pages 23 and 29; 2015/16 GRA May 28, 2015 Transcript Page 1072

Please identify whether any nuclear plants in Minnesota are scheduled to be shut down within the period to 2030. If no shut downs are publicly identified, please provide Daymark's views of whether shut downs are likely in this timeframe.

Response:

Xcel Energy (NSP) owns 1,600 MW of nuclear capacity in Minnesota, Prairie Island (2 units) and Monticello. In its recent IRP, the Company notes that its plan is to operate these units through their existing licenses (through 2034 and 2030, respectively) and include an assumption in its planning that those units retire at that time. (See PUB/Daymark-3 Attachment 1 at page 75). In a recent rate case, the review of capital cost requirements associated with future operations of Prairie Island has led to examination of the cost-effectiveness of earlier retirements. The Company included an assessment of early retirement issues and options in its IRP Supplement. (See PUB/Daymark-3 Attachment 2 at pages 46-58). The MPUC has required that the Company include plans and scenarios for retirements of Prairie Island and Monticello in its next IRP (February 1, 2019). (See PUB/Daymark-3 Attachment 3 at page 12).

Based on the foregoing public information, the issue of early retirements of these units is point of consideration in Minnesota and a possibility. Daymark has no further information on which to assess whether early retirements are likely.

PUB/DAYMARK - 7 Reference: Daymark Export Revenue Report Page 33

Please explain whether Figure 13 depicts the on-peak variance between the actual forecast prices and the short term forecast prices, or between the actual prices and the short term forecast prices. If the variance is between the actual forecast and the short term forecast, please explain what the source of the actual forecast is.

Response:

The figure compares forecasts to actual prices.

PUB/DAYMARK - 8 Reference: Daymark Export Revenue Report Page 34 and 35

a) Please explain whether Figures 14 and 15 depict the actual forecast prices or the actual prices. If the actual forecast prices are shown, please explain what the source of the actual forecast is.

b) If Manitoba Hydro has available to it three independent forecasts as well as ICE forward prices, please explain why it relies on one independently produced forecast for the short term forecast of prices.

Response:

a) All values are forecasts, not actual prices. As noted in the sentence preceding Figure 14, the “actual forecast” is the one actually used by MH in its modelling.

b) Daymark does not have documentation of MH’s rationale. Our recollection of our discussion of this topic with MH relates to the frequency of updated projections from the one vendor relative to the others. The analysis depicted in Figures 14 and 15 is a one-time benchmarking of the one forecast to the others.

PUB/DAYMARK - 10 Reference: Daymark Export Revenue Report Pages 42 and 44

Please confirm whether the prices in Figures 19 and 22 are for different pricing locations. If not confirmed, please reconcile the discrepancy in pricing.

Response:

Confirmed. The prices in Figure 19 are MHEB prices. The prices in Figure 22 are Minnesota Hub prices.

PUB/DAYMARK - 13 Reference: Daymark Export Revenue Report Pages 60 and 61; PUB/MH I-50a

Preamble: Daymark states: "Based on our review of the information on the longer-term trends in MISO (as documented in Sections II and III), the near-term market conditions that are adversely affecting the ability to sell firm power at a premium are not expected to persist for more than a few years. Our observation that the 20-year plus long-term outlook prepared by MH, assuming no premium at any point in time, is inconsistent with the rationale for instituting the premium in the first instance for years 6 to 20 of the forecast."

a) Please confirm whether Daymark's use of "premium" refers to both the premium for surplus dependable energy as well as the value of capacity.

b) If not confirmed, please indicate for which component in (a) is it inconsistent to exclude from years 6 to 20 of Manitoba Hydro's forecast of export revenues.

c) Please provide Daymark's views on an appropriate portion of surplus uncontracted sales to which Manitoba Hydro should add a dependable energy premium.

d) Please provide Daymark's views on an appropriate portion of surplus uncontracted sales to which Manitoba Hydro should add a capacity value.

Response:

a) Not confirmed. Our use of "premium" in this context excludes the capacity value. That section of the report was addressing the portion of our Scope of Work that was specific to the premium assumption. Refer to the depiction of energy, capacity and premium in Figure 28.
b) Please refer to pages 70 and 71 of the Daymark Report, specifically the discussion of "No Forecasted Capacity Revenue". In this section of the report, we discuss our observation that MH's assumption of no capacity revenues for the

surplus dependable energy and opportunity sales beyond the near term is not supported and our observation is similar to that for the premium in the cited passage from page 50.

c) MH's assumption that none of the surplus dependable energy or opportunity energy obtains capacity revenue or premiums is the lowest possible value, as discussed in the "No Firm Energy Sales" and "No Assumed Replacements for Expiring Firm Sales" sections on page 72 and 73 of the Daymark Report. In the NFAT analysis, all surplus dependable energy was assumed to receive capacity and premium values, as well as some of the surplus opportunity sales. Those two approaches, either all or nothing, bound the range of values that could be assumed for this forecast. We believe it would be helpful to the Board to understand the changes in the export revenues for at least two or three alternative assumptions, such as 1) all as in the NFAT analysis, 2) 50 % of that value, and 3) assume all existing firm commitments are renewed for the 20 year period.

d) In response to part c, we suggest scenarios to consider including both capacity and premium values. Given the requirements for capacity are more explicit in the MISO market (all entities must have capacity resources to meet resource adequacy obligations), and the projected needs for new, as yet unidentified capacity resources is large relative to MH's surplus, the Board may find it helpful to understand the changes in export revenues that would result from an assumption that all surplus dependable energy receives capacity value based on MH's consensus capacity price forecast for years 2025 and later.

PUB/DAYMARK - 14 Reference: Daymark Export Revenue Report Page 76

Please confirm whether Figure 35 incorporates the high and low natural gas price forecasts and the corresponding impacts on Fuel & Power Purchased.

Response:

Confirmed. The light blue range depicted in Figure 35 is derived using the high and low export prices derived from the use of the high and low gas price assumptions described on pages 47 to 49 of the Daymark Report.

PUB/DAYMARK - 15 Reference: Daymark Export Revenue Report Pages 66 and 67

Preamble: As part of its Report in Section VI Firm Contracts Analysis and Detailed Findings which begins on Page 64 Daymark has provided a discussion of how its calculations of revenues from export contract compare to values determined by Manitoba Hydro.

Request:

a) Please provide all notes, analysis, workpapers, and spreadsheets in working electronic form used to support the paragraph on page 66: “Through the review of documentation provided by MH, discussions with MH staff, and independent analysis of the contracts, the Daymark IEC Team has concluded that the revenue forecasts assumed by MH for carryover contracts are reasonable.”

b) Please provide all notes, workpapers, and spreadsheets in working electronic form used to support the paragraph on page 67: “For the capacity-only contracts, the calculations performed by the Daymark IEC Team matched the revenue forecasts provided by MH in MFR 84.”

Response:

a) See CONFIDENTIAL Attachment 1.

b) See CONFIDENTIAL Attachment 2.

COMMERCIALLY SENSITIVE INFORMATION

PUB/DAYMARK-CSI-1 Reference: Daymark Export Revenue Report Page 50

Preamble: "The composite carbon pricing [redacted] and are, on average, [redacted] of such prices typically considered in market assessments." 3b

Request: Please clarify what is meant by "market assessments", specifically whether this refers to other market assessments viewed by Daymark or whether these refer to the four independent forecasts used by Manitoba Hydro. If the latter, please provide additional explanation of Daymark's concern since the Manitoba Hydro consensus forecast is [redacted] independent forecasts. 3b

Response:

Market assessments refers to the four forecasts and other market assessments that Daymark has observed in other consulting engagements.

The carbon pricing assumptions in the four independent market price forecasts are depicted in Figure 18. [redacted] (values in 2017 US$). 3b

As an example of other market assessments, the Report describes the Minnesota Public Utilities Commission recent adoption of carbon pricing to be used in resource planning in Minnesota. (See Report footnote 28 on page 22). The Commission adopted low and high range values for 2017 through 2050. The 2040 values adopted are approximately $14 in the low case and $62 in the high case (2017 US$). We observe that [redacted] The range of values in this analysis is representative of the range of values we have observed in other market assessments. 3b

COMMERCIALLY SENSITIVE INFORMATION

PUB/DAYMARK-CSI-2 Reference: Daymark Export Revenue Report Page 50

Preamble: "[redacted]" 3b

Request: Please explain how this forecaster's forecast [redacted] 3b

Response:

MH uses only the energy component of the four forecasts, as it assumes no capacity revenue. However, the energy and capacity forecasts are prepared by each forecaster on a set of assumptions. [redacted] 3b

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
John A. Tuma	Commissioner

In the Matter of Xcel Energy's 2016–2030 Integrated Resource Plan

ISSUE DATE: January 11, 2017

DOCKET NO. E-002/RP-15-21

ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE RESOURCE PLAN FILINGS

PROCEDURAL HISTORY

On January 2, 2015, Northern States Power Company d/b/a Xcel Energy (Xcel) filed a resource plan under Minn. Stat. § 216B.2422 and Minn. R. 7843.0400, covering the period 2016–2030.

On January 16, 2015, the Commission issued a Notice of Comment Period and Procedures on Resource Plan, requiring Xcel to submit a revised preferred plan that incorporated resource decisions made in Docket E-002/CN-12-1240.[1] The Commission also established a public comment and reply-comment period for the resource plan.

On October 2, 2015, in response to stakeholder comment filings and information requests, Xcel filed reply comments proposing significant changes to its resource plan.

On January 6, 2016, the Commission issued an order requiring Xcel to supplement its resource plan no later than January 29, 2016, by filing updated plans and related additional analysis.[2] The order provided that the Commission would establish a procedural schedule after the Minnesota Department of Commerce (the Department) had an opportunity to initially review the filing and make procedural recommendations.

[1] In Docket E-002/CN-12-1240 the Commission approved certain power purchase agreements to meet identified resource needs arising before 2019. *In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need*, Order Approving Power Purchase Agreement with Calpine, Approving Power Purchase Agreement with Geronimo, and Approving Price Terms With Xcel (February 5, 2015).

[2] Order Requiring Supplemental Filing (January 6, 2016).

On January 29, 2016, Xcel filed a supplement describing its "Current Preferred Plan." The supplemented resource plan proposed:

- Ceasing coal operations at Sherburne County Generating Station (Sherco) Units 1 and 2 in the 2020s;
- Adding 1,400 megawatts of large-scale solar (400 megawatts by 2020);
- Adding 1,800 megawatts of wind (800 megawatts by 2020);
- Adding natural gas generation in the 2020s, including a combustion turbine generator in North Dakota, and a combined cycle generator on the Sherco site by 2026.

On February 29, 2016, after conducting discovery and holding discussions with the Company, the Department filed its review of the plan and made procedural recommendations.

On March 3, 2016, the Commission requested comments on whether Xcel's Current Preferred Plan is in the public interest.

By July 8, 2016, the Commission received comments from:

- Becker City Council
- Fresh Energy, Minnesota Center for Environmental Advocacy, Sierra Club, and Wind on the Wires (the Clean Energy Organizations)
- EDF Renewable Energy
- Enel Green Power North America, Inc.
- Hennepin County
- Institute for Local Self-Reliance
- Invenergy LLC
- Minnesota Department of Commerce (the Department)
- Minnesota Pollution Control Agency
- Minnesota State Representative Jim Newberger
- NextEra Energy Resources, LLC
- Prairie Island Indian Community
- St. Paul Cogeneration, LLC
- Sherburne County Administration
- Flint Hills Resources, LP; Gerdau Ameristeel US Inc.; Unimin Corporation; and USG Interiors LLC (the Xcel Large Industrials)

By August 12, 2016, the Commission received reply comments from:

- City of Red Wing
- Center for Energy and Environment
- City of Minneapolis
- the Clean Energy Organizations

- Health Professionals for a Healthy Climate
- the Saint Paul Area Chamber of Commerce
- Sierra Club-organized individuals and organizations
- Xcel Energy
- Xcel Large Industrials
- 3 individuals via SpeakUp

On September 13, 2016, the Department submitted supplemental comments. The Department recommended approval of Xcel's revised resource plan, with further modifications and additional filing requirements.

On October 6 and 13, 2016, the Commission met to consider the matter.

FINDINGS AND CONCLUSIONS

I. Summary of Commission Action

In this order, the Commission will approve a modified version of Xcel's supplemented resource plan and set requirements for future resource plan filings. The Commission will:

- approve the acquisition of at least 1000 MW of wind generation by 2019 and at least 650 MW of solar generation by 2021;
- approve the retirement of Sherco 2 in 2023, and Sherco 1 in 2026;
- determine that there will likely be a need for approximately 750 MW of intermediate capacity coinciding with the retirement of Sherco 1 in 2026.

The Commission will also approve resource acquisition processes to meet anticipated generation needs in a manner consistent with the public interest.

II. Legal Background

A public utility providing electricity to at least 10,000 customers and capable of generating 100 megawatts (MW) of electricity must file a resource plan or report for the Commission's approval, rejection, or modification. A resource plan or report generally details the projected need for electricity in its service territory for a forecasted planning period, and the utility's plans for meeting projected need, including the actions it will take in the next five years.[3] Resource plans are evaluated on their ability to:

> A. maintain or improve the adequacy and reliability of utility service;
>
> B. keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;

[3] Minn. Stat. § 216B.2422; Minn. R. Chap. 7843.

> C. minimize adverse socioeconomic effects and adverse effects upon the environment;
>
> D. enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and
>
> E. limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.[4]

To reliably provide the electricity demanded by its customers, an electric utility considers both supply and demand. The utility can supply electricity through a combination of generation and power purchases, and by reducing the amount of electricity lost through transmission and distribution. The utility can manage customer demand by encouraging customers to conserve electricity or to shift activities requiring electricity to periods when there is less demand on the electric system. A resource plan contains a set of demand- and supply-side resource options that the utility could use to meet the forecasted needs of retail customers.[5]

By integrating the evaluation of supply- and demand-side resource options—treating each resource as a potential substitute for the others—a utility can find the least-cost plan that is consistent with legal requirements and policies.

Although the Commission must approve, reject, or modify the resource plans of investor-owned utilities, the resource-planning process is largely collaborative and iterative.

The process is collaborative because there are a wide array of facts and considerations that may be relevant to resource choices or deployment timetables. The facts on which resource decisions depend—how quickly an area and its need for electricity will grow, how much electricity will cost over the lifetime of a generating facility or a purchased-power contract, how much conservation potential the service area holds and at what cost—all require the kind of careful judgment that sharpens with exposure to the views of engaged and knowledgeable stakeholders.

The process is iterative because analyzing future energy needs and preparing to meet them is not a static process; strategies for meeting future needs are always evolving in response to changes in actual conditions in the service area. When demographics, economics, technologies, or environmental regulations change, so do a utility's resource needs and its strategies for meeting them.

III. Xcel's Resource Plan

Xcel projects that, under median forecast conditions, it will have sufficient generation capacity until the mid-2020s, but that three main factors will lead to a need for additional generating capacity in or around 2025. The Company expects the need for new generating capacity to be driven primarily by: (1) Xcel's proposal to retire Sherco units 1 and 2 (1,400 MW of generating capacity), (2) the retirement of roughly 850 MW of aging, Xcel-owned peaking plants, and (3) the expiration of power purchase agreements (PPAs) for more than 2,000 MW. The exact timing

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

[5] Minn. Stat. § 216B.2422, subd. 1(d).

and amount of the anticipated need depends on the timing of plant retirements as well as the adoption of community solar gardens (CSGs) and other factors.

Xcel used an industry-standard modeling tool called Strategist to analyze its projected resource needs and propose its preferred plan for meeting the need. Based on its analysis, Xcel proposed to acquire 1,400 MW of large-scale solar, 1,800 MW of wind, and 2,856 MW of natural gas generation over the planning period.

To address a portion of the identified need, the Company specified that it preferred to use the Sherco site for an approximately 800 MW combined cycle natural gas plant. The Company acknowledged that its proposal goes beyond the Commission's historical approach to resource planning by specifying a location for a proposed plant. Xcel asserted that determining the proposed plant's size, type, timing, *and* location in this proceeding would be appropriate because the location is supported by reliability and socioeconomic factors and because a location determination now would provide certainty to employees and the community, which would likely be affected by retirement of Sherco units 1 and 2.

The Department replicated Xcel's modeling in Strategist, reviewed the Company's base assumptions, and ran additional scenarios under a variety of contingencies (or sensitivities). Based on its analysis and modeling, the Department made its own planning recommendations. Overall, the Department largely agreed with Xcel's planned resource additions and retirements, and recommended approval of the plan with modifications.

Concerns about Xcel's plan raised by the Department and other commenters fell into three broad categories: forecasts, modeling, and assumptions underlying the plan; details of proposed five-year and intermediate-term resource decisions; and information needed to evaluate future resource plans. These issues are addressed, with plan modifications and filing requirements where appropriate, in the sections below.

IV. Forecasting

Xcel forecasted energy requirements and peak demands from 2016 through 2030 using monthly data from 1998 to 2014. The Department raised concerns about the analyses Xcel used to reach its forecasting conclusions.

A. Positions of the Parties

The Department recommended approval of Xcel's base energy forecast and peak demand forecast for planning purposes only. In particular, the Department argued that the forecast results were subject to some uncertainty and, in light of the uncertainty, the use of the forecasts should be limited.

At the Commission meeting, Xcel agreed with the Department that its energy and peak demand forecasts should only be used for planning purposes.

B. Commission Action

The Commission agrees that Xcel's Strategist-modeled energy and demand forecast is acceptable for planning purposes but concludes it should not be used to support any resource acquisition proposal beyond the five-year action plan. Disagreement over Xcel's methodology for forecasting the long-term peak-demand growth rate and the long-run effects of Demand Side Management raise doubts about the forecasts' usefulness beyond the five-year action plan. The Commission is persuaded that the use of these forecasts should be limited as the Department has proposed. Resource acquisitions beyond the five-year plan should be subject to a more contemporaneous demonstration of need. The Commission will so order.

V. Five-Year Action Plan

Based on its forecasts, Xcel initially proposed adding 400 megawatts of large-scale solar by 2020, and 800 megawatts of wind. While generally supportive of Xcel's proposed resource additions, the Department recommended slightly different quantities and timing. Other commenting parties were also generally supportive of Xcel's proposals for wind and solar acquisitions through 2021.

The process or processes by which Xcel would pursue approved wind and solar resource acquisitions was subject to more disagreement. The process for acquiring generation resources can have a significant effect on the type, cost, and ownership structure of proposals submitted for consideration and ultimately chosen for acquisition. Xcel's proposal included 50% Company-owned wind resources.

A. Positions of the Parties

Xcel proposed to use what it characterized as a modified Track 1 Request for Proposals (RFP) process[6] to both acquire wind projects and demonstrate the competitiveness of its self-build proposal. Xcel's proposal contained features of both track 1 and track 2 acquisition processes—it contemplates both competitive bidding and a competing Company-owned resource proposal.

The Company proposed the following process:

1) Xcel issues an RFP for wind resources.[7]

[6] The Commission has approved a two-track resource acquisition process—which among other things provides that a competitive bidding process governs when Xcel does not submit a proposal in a competitive resource procurement process (Track 1), and that a Certificate-of-Need-like process governs procurement when Xcel does submit a proposal (Track 2). *In the Matter of Northern States Power Company d/b/a Xcel Energy's Application for Approval of its 2004 Resource Plan*, Docket No. E-002/RP-04-1752, Order Establishing Resource Acquisition Process, Establishing Bidding Process Under Minn. Stat. § 216B.2422, Subd. 5, and Requiring Compliance Filing (May 31, 2006). More detail on the lengthy history of the two-track bidding process can be found in the Department's Comments, pp. 44–50. (July 8, 2016).

[7] Xcel issued an RFP for wind resources on September 22, 2016, with a bid deadline of October 25, 2016. The Company states that it anticipates seeking Commission approval for agreements arising from the RFP in early 2017. Xcel Letter, this docket (September 22, 2016).

2) The day prior to receiving wind bids, Xcel will submit its own self-build proposal including estimates of final costs.

3) Xcel will evaluate the bids and select projects for negotiations based on a list of factors (factors which Xcel outlined in its reply comments).

4) Xcel will file with the Commission the results of the bidding process, project rankings, its analysis, and the results of a third party auditor's report of its bidding and review process. Additionally, Xcel will evaluate the criteria outlined in the Minn. Stat. § 216B.243, subd. 9 certificate of need exemption for renewable energy standard (RES) facilities.

Xcel argued that this modified or hybrid acquisition process was appropriate to ensure the timely and cost-effective acquisition of wind resources and to reduce the burden on wind developers. The Company also argued that Commission approval of the proposed process would exempt the chosen projects from a certificate of need requirement under Minn. Stat. § 216B.2422, subd. 5.

The Department, on the basis of its independent modeling and analysis, recommended that the Commission modify Xcel's action plan to acquire about 1,000 MW of wind by 2019 (instead of 800 MW in 2018) and to remove the large-scale solar from the action plan to allow for greater certainty from the CSG program. The Department also recommended that the Commission approve Xcel's proposed, modified acquisition process,[8] with the proper mix of purchased power and Company-owned resources determined by the facts established during the acquisition process regarding alternatives.

The Clean Energy Organizations advocated for a transparent acquisition process that would accommodate a variety of ownership structures and for regulatory oversight to protect ratepayer and public interests. The Institute for Local Self-Reliance objected to the Company's proposal to commit to Xcel's contemplated 50% Company ownership of proposed wind resources.

B. Commission Action

Despite slight variation in the exact timing and magnitude, the record clearly showed that acquisition of wind and possibly solar resources in the next five years represents the least-cost method of meeting Xcel's near-term resource needs. The Commission finds that the record shows that it is reasonable to acquire at least 1000 MW of wind by 2019. This acquisition is least-cost even though Xcel does not show a planning capacity deficit until the mid 2020s because it will provide incrementally lower-cost energy, thereby reducing system costs. Upon submission of evidence such as price, bidder qualifications, rate impact, transmission availability and location, additional acquisitions may be approved.

The Commission will modify Xcel's plan to acquire 400 MW of large-scale solar in 2016–2021. Instead, Xcel will be required to acquire approximately 650 MW of solar in this timeframe through a combination of the Company's community solar gardens program or other acquisitions (without limitation to "large-scale" solar). The Company may pursue additional, cost-effective

[8] Though initially the Department's recommendation was limited to approving a process for proposed wind acquisitions, at the Commission meeting the Department elaborated on its recommendation, agreeing with a proposal that the Commission "authorize use of the modified Track 2 bidding process and authorize the process as a Commission-authorized bidding process [under Minn. Stat. § 216B.2422, subd. 5(c)]" without expressing a requirement that the process be limited to wind acquisitions.

solar resources if it is in the best interests of its customers. Xcel shall report on its progress in its next resource plan.

Minn. Stat. § 216B.2422, subd. 5(a), provides that a utility may select resources to meet its projected energy demand through a bidding process approved or established by the Commission. The Commission established the existing two-track bidding process for Xcel just over a decade ago. Having reviewed the Company's proposed, modified acquisition process, the Commission agrees that it is a reasonable method of acquiring wind and solar resources in the 2016–2021 timeframe.

The Commission will therefore approve the bidding process described by Xcel for the limited purpose of acquiring wind and solar resources in the 2016–2021 timeframe. The Commission declines to approve the proposed acquisition process without limitation because the two-track process has provided needed certainty and transparency for participants and regulators. But in this case, given the scope and nature of the needed acquisitions, and the need for prompt action, the Commission agrees that the proposed modified process is reasonable and appropriate.

VI. Intermediate Term—Sherco Units 1 and 2

Xcel proposes to retire Sherco Units 1 and 2 before 2030. The two generating units produce approximately 1,400 MW of capacity and associated energy. Together with its proposal to retire the two units, Xcel proposes to construct a 780 MW combined-cycle generating unit on the Sherco site.

A. Positions of the Parties

There was no material disagreement among stakeholders over the proposed retirement of Sherco Units 1 and 2. Retirement of these units is supported by the Company's and Department's modeling showing that retirement is part of virtually every least-cost planning scenario, with some room to argue over the precise year in which to retire each unit.

While the need for some additional resources between 2025 and 2030 was relatively uncontroversial, details of Xcel's proposal drew some criticism, particularly the proposal to identify a specific generator fuel-type and location to meet the identified need. The Company asserted that socio-economic and technical factors justified identifying a fuel type and location as part of this proceeding.

Apart from the Sherco location's general suitability for new generating facilities because a generating facility is already sited there, Xcel argued that committing to the location would clearly mitigate the negative impact of the plant retirements for that community. It also argued that from a business planning perspective having those details decided well in advance would facilitate the Company's efforts to smoothly transition employees in the retiring plants. Finally, it contended that engineering studies showed that a combined cycle generator on the Sherco site would be uniquely well-suited to address grid reliability concerns that would need to be addressed in the same time frame.

Xcel's proposal received support from the City of Becker and Sherburne County Administration, and State Representative Jim Newberger. These commenters identified that retirement of the Sherco coal-fired plants would be detrimental to the local economy, and that building replacement generation on the site would mitigate the negative impact.

The Department, the Clean Energy Organizations, and the Xcel Large Industrials objected to a decision that would commit to specifics such as the exact location, fuel type, and generation capacity. They argued that the need for a decision on those details was not immediate, and would be better left for future consideration—which would allow more flexibility to consider alternatives in the meantime.

B. Commission Action

Historically, the Commission has used resource planning as a tool to assess and determine the appropriate size, type, and timing of generation resources. At issue is the level of planning detail the Commission should commit to as part of approving this resource plan.

At the Commission meeting, it became clear that the distance between the stakeholders' positions is small but nuanced. Xcel wishes for the Commission to approve an approximately 780 MW combined cycle facility at a particular location. The Department recommended that the Commission find a need for approximately 750 MW of "intermediate capacity."[9] And the Clean Energy Organizations recommended that the Commission find a need for approximately 750 MW of capacity.

The Commission is persuaded by the argument that, given the Sherco retirement dates of 2023 and 2026, it is premature at this time to determine with specificity the fuel type and location to address the identified 750 MW capacity need. The Commission is not persuaded that alternatives to the reliability concerns raised by Xcel have been fully considered, and believes there is adequate time to explore other resource options and consider the relevant socioeconomic factors without jeopardizing the feasibility of Xcel's preferred plan to build a combined cycle unit on the Sherco site.

Therefore, the Commission concludes that, more likely than not, there will be a need for approximately 750 MW of intermediate capacity coinciding with the retirement of Sherco 1 in 2026. The Commission will authorize a certificate of need process to evaluate options for addressing this anticipated need. The process will allow consideration of resources or resource combination alternatives that meet the identified resource and reliability need without prejudging or foreclosing Xcel's preferred plan. Potential need-addressing alternatives between 2025 and 2030 could include renewal of some expiring PPAs, additional demand response, or some other new generation.

The certificate of need process will also be based on a more precise and contemporaneous forecast. Under Minn. Stat. § 216B.243, the Commission must consider the accuracy of the long-range energy demand forecasts offered to justify a certificate of need. As stated above, the forecasts in this resource plan may not be used to support acquisitions beyond Xcel's five-year action plan. At the Commission meeting, Xcel agreed that a certificate of need filing would incorporate an updated energy and demand forecast for Commission evaluation.

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[9] The Department defined "intermediate" capacity facilities as having an overall capacity factor of 20–40%, as distinct from "baseload" (higher capacity factor), and "peaking" (a lower capacity factor). Capacity factor reflects the ratio of a facility's actual output over time relative to its nameplate capacity.

VII. Intermediate Term—Other Resources

The Commission will also require Xcel to evaluate and pursue other resource options between 2023 and 2030. In light of rapidly changing costs among potential energy and capacity sources, Xcel must maintain flexibility and consider a broad range of resource options. In addition to requiring evaluation of combinations of supply-side, demand-side, and transmission alternatives to address its 750 MW need identified above, Xcel's plan must include the acquisition of no less than 400 MW of additional demand response by 2023. This level of potential demand response capacity is supported by even the most conservative study of Xcel's system in the record.

For reasons similar to those stated above regarding the contemplated Sherco replacement, Xcel's planned additions of combustion turbine generation in 2025–2030 will also be modified to be less specific. Rather than approve a plan with a specific generation type or location for those resource additions, the Commission concludes that a plan that does not specify location or generation type in that time frame will be more consistent with the public and ratepayer interests.

VIII. Requirements for Future Resource Plans

Finally, the Commission will direct that Xcel investigate, evaluate, and discuss an array of resource and planning issues that arose during the course of this proceeding. Major plant retirements are coming over Xcel's planning horizon in upcoming resource planning cycles, and it is important that Xcel, the Commission, and stakeholders regard system needs holistically. As this proceeding demonstrated, individual plant retirements can give rise to complex locational and system concerns that, without sufficiently forward-looking planning, may constrain future decisions. Considering the future of Xcel's system as a whole as its generation fleet ages will help maximize planning flexibility.

ORDER

1. Xcel Energy's 2016–2030 Resource Plan is approved with the modifications required by this order.

2. Xcel's Strategist-modeled energy and demand forecast is acceptable for planning purposes but may not be used to support any resource acquisition proposal beyond the five-year action plan.

3. It is reasonable to acquire at least 1000 MW of wind by 2019. Acquisition of greater than 1000 MW may be approved upon submission of evidence such as price, bidder qualifications, rate impact, transmission availability, and location.

4. Xcel's resource plan is modified as follows:

    a. to remove 400 MW of large-scale solar in 2016–2021. Xcel shall acquire approximately 650 MW of solar in 2016–2021 through a combination of the Company's community solar gardens program or other acquisitions. The Company may pursue additional, cost-effective solar resources if it is in the best interests of its customers.

    b. to change Xcel's proposed Fargo combustion turbine to a generic combustion turbine.

c. to change Xcel's planned CT additions in the 2025–2030 time frame to provide instead for adding the most cost-effective combination of resources consistent with state energy policies, including but not limited to the following resource options: large hydropower, short-term life extensions of Xcel-owned peaking units, natural gas combustion turbines, demand response, utility-scale solar generation, energy storage, and combined heat and power.

5. Concerning wind and solar resource acquisitions, Xcel:

   a. may use the modified Track 2 process for the acquisition of wind resources included in the five-year action plan, and for any additional solar, if needed, through 2021;

   b. shall, if Xcel intends to provide a bid for wind generation, acquire wind resources through the modified Track 2 process.

   c. shall file a contingency plan early in the process (preferably with the filing of the Company's self-build proposal) to address the potential for the bidding process to fail; and

   d. shall, in wind acquisition proceedings, describe how revenues from wind generation sold into the MISO market will be returned to Minnesota ratepayers, and provide an estimate of these revenues.

   The proper mix of purchased power and Company-owned resources shall be determined during the resource acquisition process.

6. In any filing seeking approval of wind resources, Xcel shall discuss each project's wind curtailment risk.

7. Xcel's schedule to retire Sherco 2 in 2023, and Sherco 1 in 2026, is approved.

8. The Commission finds that more likely than not there will be a need for approximately 750 MW of intermediate capacity coinciding with the retirement of Sherco 1 in 2026.

9. Xcel is authorized to file a petition for a certificate of need under Minn. Stat. § 216B.243 to select the resource or resource combination that best meets the system resource and reliability needs associated with the retirement of Sherco 1 in 2026. The Company's filing and the proceeding shall:

   - evaluate combinations of supply-side, demand-side, and transmission alternatives;
   - consider location-specific factors related to socioeconomic impacts on the local community and regional reliability;
   - allow for utility ownership of replacement resources if determined to be in the best interest of customers;
   - comply with all relevant state energy policies; and
   - ensure public participation.

10. Xcel shall acquire no less than 400 MW of additional demand response by 2023.

11. An average annual energy savings level of 444 GWh for all planning years is approved.

12. Xcel shall investigate the potential for an energy-efficiency competitive bidding process for customers that have opted out of the statewide Conservation Improvement Program (CIP) under Minn. Stat. § 216B.241, subd. 1a(b).

13. Xcel shall file its next resource plan on February 1, 2019.

14. In its next resource plan filing, Xcel shall:

    a. describe its plans and possible scenarios for cost-effective and orderly retirement of its aging baseload fleet, including Sherco, King, Monticello, and Prairie Island.

    b. evaluate combinations of supply-side (distributed and centralized), demand-side, and transmission solutions that could in the aggregate meet post-retirement energy and capacity needs as well as contribute to grid support.

    c. explore the role of cost-effective combined heat and power solutions.

    d. report on its solar acquisition progress.

    e. provide a full and thorough cost-effectiveness study that takes into account the technical and economic achievability of 1,000 MW of additional demand response, or approximately 20% of Xcel's system peak in total by 2025.

    f. summarize its investigation and findings concerning the potential for an energy-efficiency competitive bidding process for customers that have opted out of CIP.

15. In future resource plan filings, analysis and inputs must, to the extent possible, be consistent with Xcel's distribution system planning.

16. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Daniel P. Wolf
Executive Secretary

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I. EXECUTIVE SUMMARY

Partnerships with communities, customers, and stakeholders have helped to make Minnesota a leader in energy policy - collaboration has been the hallmark of this proceeding. As our industry enters an era of increasing responsiveness to evolving expectations – from those of individual customers, to federal and state carbon emissions goals – these partnerships will become even more important to charting a path that provides certainty in uncertain times.

The Commission noted in its January 6, 2016 Order that resource planning is a collaborative and iterative process and that a full understanding of the relevant facts requires exposure to the views of engaged and knowledgeable stakeholders. The Commission also explained that the process of analyzing future energy needs and preparing to meet them is not a static process, and that strategies for meeting future needs evolve in response to changing conditions. We agree. Through significant collaboration with our stakeholders, our Current Preferred Plan has evolved from a plan that would achieve a 40 percent carbon dioxide emissions reduction from 2005 levels to one that achieves a nearly 60 percent reduction in the same timeframe.

After filing our initial resource plan in January 2015, we engaged in informal discussions and conducted several technical workshops to receive feedback from our stakeholders. We listened carefully to this feedback, we reviewed and analyzed the comments filed in this docket, and we shared an updated vision of our energy future that resulted from this collaboration in our October 2, 2015 Reply Comments.

As described in those Reply Comments, we envision an energy future that transitions our generation fleet such that we will achieve a dramatic reduction in carbon and by 2030, our energy mix will be 63 percent carbon-free. Taking action to transition our fleet now mitigates the costs and risks of retiring a significant proportion of our baseload generation in the same time period. It will also mitigate environmental regulatory risks that could affect the economic viability of our older coal units, and provides certainty to our customers and stakeholders throughout the planning period. Our proposal to achieve this vision will benefit our customers, states, and the communities we serve in a variety of ways. It will benefit our customers by providing for a cost-effective transition to the cleaner energy future they want, while preserving the reliable and safe service they expect. As discussed further below, we can accomplish this transition for just a fraction of a percent more in incremental cost over earlier plans.

Our Current Preferred Plan will also benefit our states by advancing both federal and state energy policies and by being nearly certain to comply with the final Clean Power Plan rules. Finally, our Current Preferred Plan will benefit our communities. It allows adequate time to transition our workforce during this fleet evolution, and provides for new investments and the creation of new jobs in current and future host communities. For these reasons, we believe that our Current Preferred Plan charts the right path forward for our Company and stakeholders.

Our Current Preferred Plan consists of the following course of action:

- Accelerating our transition away from coal by ceasing operation of our Sherco Units 1 and 2 in the 2020s,
- Adding 1,400 megawatts of large solar to our system, including 400 megawatts by 2020,
- Adding 1,800 megawatts of wind, including 800 megawatts by 2020,
- Adding natural gas generation in the 2020s,
- Operating our carbon-free nuclear fleet through their existing plant licenses, and
- Continuing our commitment to increased energy efficiency and seeking out new technologies that will advance customer-driven solutions.

As we make this transition, maintaining the reliability of the system is critical. Our reliability studies confirm that, before ceasing coal operations at the second Sherco unit in 2026, we must take measures to maintain reliability. Our operational analysis confirms that the most cost-effective way to stabilize the transmission system and meet our customers' load requirements is to build a combined cycle plant at the existing Sherco site. By locating the plant at Sherco, we are able to use existing infrastructure and interconnection rights, which will result in significantly lower costs as compared to locating it elsewhere. We can also use our existing water allocation to wet-cool the plant, further improving cost and performance. Finally, we believe that the impacts on the Becker community should be properly considered in this proceeding, and the siting of a combined cycle at Sherco will promote economic development for the community. We also propose to add a combustion turbine near one of our load centers in North Dakota. This will balance the interests of the states that we serve and maintain the benefits of an integrated system for all of our customers, while also addressing the reliability concerns of the North Dakota commission, which wants the Company to build cost-effective and dispatchable generation in their state.

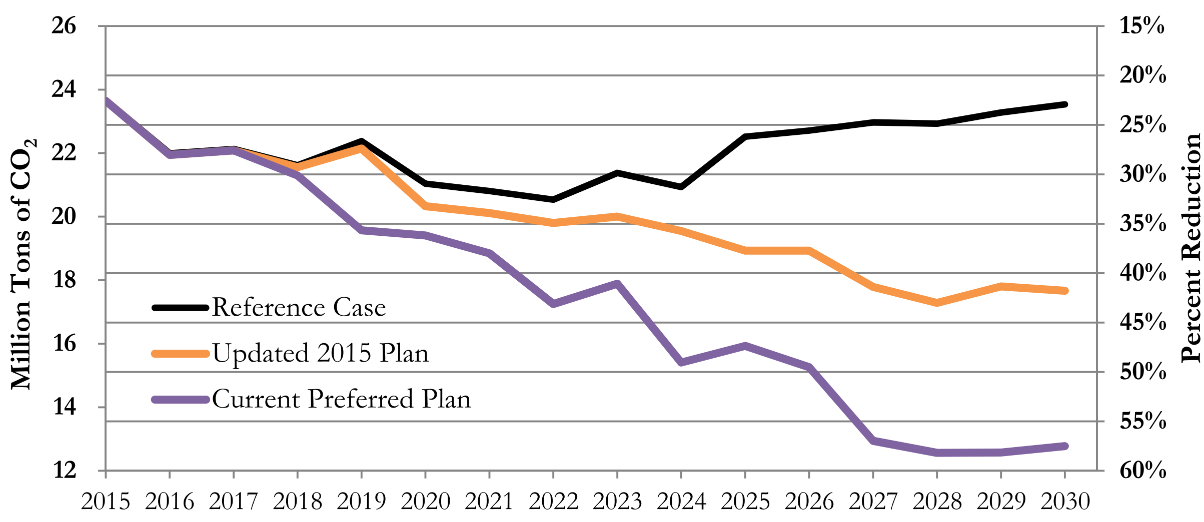
We recognize that site-specific generation is not typically a part of traditional resource planning analysis. However, the plan components we are proposing will have wide-ranging impacts on our system and region, making a locational analysis imperative to ensuring continued reliability and maximizing customer benefits. For these reasons, and those discussed later in this Supplement, we believe that a locational analysis is appropriate and in the public interest.

Our ownership of these assets, along with a balanced portfolio of the renewable generation we propose to add to the system, is a critical component of our vision, because it results in a balanced generation portfolio that will minimize customer costs and mitigate risk. The specific benefits of ownership include investment in our communities, continued use of our interconnection rights at Sherco, long-term value for our customers arising from the asset life of owned resources, increased diversity in our generation portfolio, and a demonstration of our commitment to being a leading provider of cleaner and greener energy. Our ability to secure these benefits for our customers is a critical component of our Current Preferred Plan and, we believe, an important factor in the public interest analysis.

Finally, because our nuclear fleet comprises more than half of the Company's carbon-free generation, it is a cornerstone to our carbon-reduction goals. We continue, therefore, to support operating our nuclear fleet through the end of each plant's respective current licensed life. In October, we acknowledged our projected increase in the capital costs necessary to run the Prairie Island nuclear plant to the end of its current licensed life. At the hearing on December 3, 2015, the Commission sought additional information on the increased capital forecast, and we have since studied the Prairie Island numbers in greater depth. Two key conclusions emerged from this study. First, the lower fixed operating and maintenance costs we have experienced relative to our 2008 modeling projections more than offset the increased capital projections – by more than $950 million. Second, even with the increased capital costs (the bulk of which occur in 2021 and beyond), Prairie Island has been, and continues to be, a cost-effective resource.

We recognize however, that stakeholders would like to better understand the implications of our updated forecast, as well as the potential for future updates. To help promote a better understanding of these costs, we are including a detailed discussion of Prairie Island in this Supplement. We believe that this information supports our continued operation of the plant, including the near-term investments we must make to safely and reliably operate our plants over the next few years. We acknowledge, however, that it is impossible to perfectly forecast costs for the remaining 19 years of the plant's licensed life and recognize that stakeholders may want to explore alternatives based on that uncertainty. We therefore provide some preliminary analysis relating to an alternative path for Prairie Island (an "off-ramp") sometime in the mid-2020s. We recognize that there are other alternatives, but our analysis confirms that any near-term retirement would be significantly more costly than one in the mid-2020s or beyond. We agree that it makes sense to continue a dialogue regarding the future of Prairie Island. If the Commission wishes to further explore alternatives to operating Prairie Island through its current licenses, we are committed to doing the work necessary to advance this discussion, and anticipate that it could be completed within 18 months. At the same time, we believe that this Supplement demonstrates that the continued operation of Prairie Island is cost-effective and in the public interest in the near term, such that our continuing dialogue should not impede approval of our Current Preferred Plan.

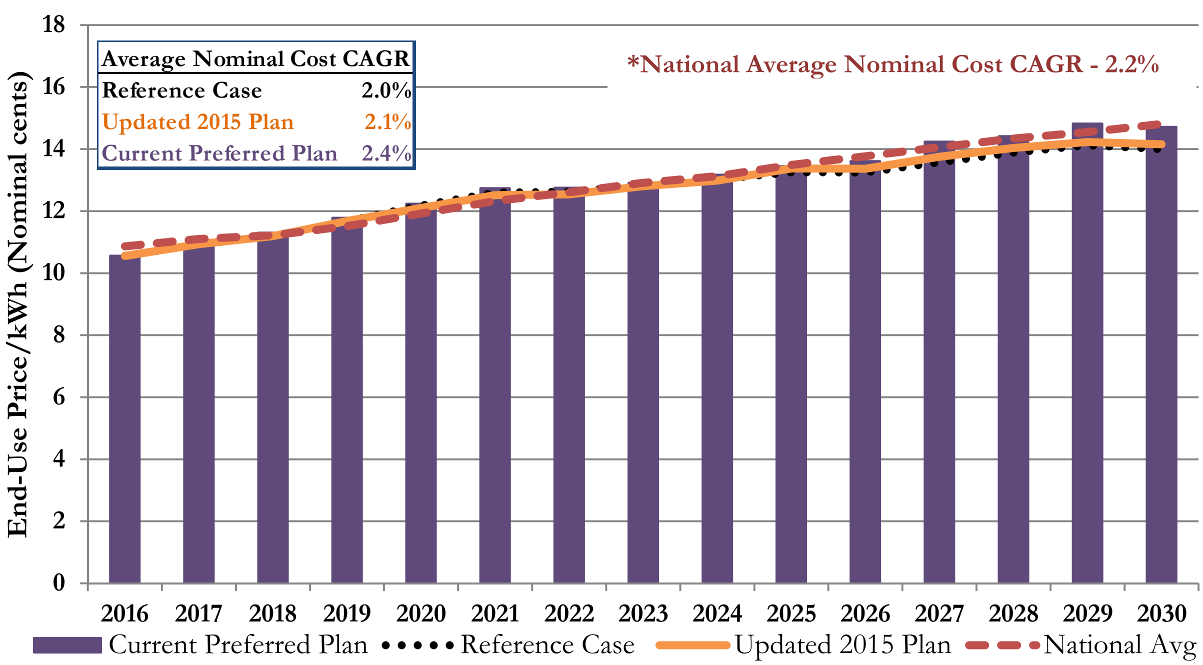
Together, these actions will result in a significant transformation in our generation fleet, including a nearly 60 percent reduction in carbon emissions by 2030. The following graph shows the dramatically reduced carbon emissions that would result from our Current Preferred Plan, as compared to both our Updated 2015 Plan and Reference Case:



While the Updated 2015 Plan would have achieved substantial progress toward federal and state energy goals, the Current Preferred Plan – which grew out of the 2015 Plan through hard work and collaboration with stakeholders – does more. It moves Minnesota significantly closer to achieving its goal of 80 percent carbon reduction by 2050, and it is the only scenario that is nearly certain to be compliant with the Clean Power Plan.

Our Current Preferred Plan achieves these goals without significantly impacting customer costs, reliability, our employees, or the communities we serve.
In fact, due to recent extensions to federal tax incentives for solar and wind generation, the cost of our Current Preferred Plan is even lower than we anticipated in our October Reply Comments. We can now offer a plan that achieves 50 percent more carbon reduction than our Updated 2015 Plan for a nominal customer cost of less than one-half of one percent Compound Annual Growth Rate (CAGR) over that plan. The opportunity to achieve such significant reductions in our carbon emissions for a nominal increase in customer cost is one of the principal benefits of our Current Preferred Plan, which is reflected in the Strategist modeling discussed in detail later in this supplement.

As we would expect, the trajectory of our Current Preferred Plan deviates from our Reference Case and Updated 2015 Plan mostly in the out years of the planning period, after we complete the transition away from coal operations at Sherco Units 1 and 2. The following graph shows the relative cost growth of our Current Preferred Plan, Updated 2015 Plan, and Reference Case, in comparison to the national average:



*National energy cost forecast from Energy Information Administration (EIA) Annual Energy Outlook 2015, Table Energy Supply, Disposition, Prices and Emissions. End use prices, all sector average.

As shown above, the cost of the three plans are comparable and roughly consistent with the expected national average increase in energy prices over the planning period.

Our Current Preferred Plan is in the public interest. It builds on our strong foundation of environmental performance, and ensures we will continue to reliably meet our customers' electricity needs in a cost-effective manner. It puts the Company on a path to transform its fleet in a planful, coordinated way that ensures we will meet our obligations under the Clean Power Plan and the most stringent of our state renewable energy and carbon reduction requirements. Implementation of our plan will put Minnesota at the forefront to lead the nation in clean energy, and at the same time, acknowledges and constructively addresses the unique policy preferences of the NSP System states. It provides our customers, employees, and communities with certainty while also maintaining flexibility to adjust and respond to changes along the way. Our Current Preferred Plan maintains a balanced diversity of energy sources and provides investment opportunities that will benefit the economies and communities in the states we serve. Finally, it promotes an orderly, gradual transition of our generation fleet and thus avoids a scenario where the Company may have to retire and replace five baseload generating facilities in the early 2030s.

To be sure, the process for approving this Resource Plan has taken longer than anticipated, and our Current Preferred Plan charts a path that is longer still. We believe, however, that a fleet transformation of this magnitude and scope requires a deliberate process, and that our Current Preferred Plan is a direct result of our deep engagement with stakeholders throughout this process. We have completed an extensive analysis since our October Reply, as well as in response to the Commission's January 6, 2016 Order. We are therefore appreciative of this opportunity to share our analysis and additional information in support of our Current Preferred Plan and look forward to engaging with our stakeholders to continue the constructive dialogue that brought us this far.

II. BACKGROUND

The Company submitted its 2016-2030 Upper Midwest Resource Plan on January 2, 2015, as required by the Commission's May 23, 2014 Order in the Competitive Acquisition Process (CAP) proceeding, which was an outcome from our last

Resource Plan.[1] The Commission made determinations in that proceeding in December 2014, which, due to the timing, we were unable to incorporate into our Initial Filing.

On January 16, 2015, the Commission issued a NOTICE requiring the Company to supplement its Resource Plan with a revised Preferred Plan that incorporated the CAP resource decisions. On March 16, 2015, we submitted a Supplement incorporating the CAP resources, the 187 MW Solar RFP Portfolio the Commission approved in February 2015 in Docket No. E002/M-14-162, an acceleration of small solar additions to reflect the Community Solar Gardens proceeding, and additional modeling and discussion that resulted from our stakeholder engagement.[2]

Parties commented on the completeness of our Resource Plan on April 3, 2015, and as part of our April 17, 2015 Reply to those Comments, we submitted a detailed five-year rate analysis of our updated Preferred Plan. On July 2, 2015, parties commented on our Preferred Plan.

On October 2, 2015, we replied to parties' comments, in part committing to maintain a goal of 1.5 percent Demand Side Management (DSM) through the planning period and find ways to stimulate greater demand response with our customers – and in addition, outlined a Revised Proposal that would transition our system from coal generation, advance the acquisition of significant levels of renewable generation, recognize nuclear energy as a critical carbon-free baseload resource, and confirm our commitment to energy efficiency efforts. We also proposed to supplement the record with a detailed analysis supporting our Revised Proposal on January 29, 2016.

On January 6, 2016, the Commission approved our request to submit a Supplement on January 29, 2016, and set forth several informational requirements for the Supplement.[3] The Commission's Order additionally set a 30-day period within which the Minnesota Department of Commerce (Department) is to submit a letter to the Commission recommending a comment period and whether any additional information is needed. After reviewing the Department's recommendation and recommendations from any other party, the Executive Secretary is authorized to set a Reply Comment period.

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[1] Docket No. E002/M-12-1240.
[2] Docket No. E002/M-14-162.
[3] *See* ORDER REQUIRING SUPPLEMENTAL FILING, Docket No. E002/RP-15-21 (January 6, 2016).

We note that in this Supplement, we have updated the naming of our scenarios from our past filings to properly reflect our Current Preferred Plan for which we seek regulatory approval as follows:

January 2, 2015 Initial Filing	**March 16, 2015 Supplement**	**October 2, 2015 Reply Comments**	**January 29, 2016 Supplement**
Reference Case	Reference Case	Reference Case	Reference Case
Preferred Plan	Updated Preferred Plan	Preferred Plan	Updated 2015 Plan
N/A	N/A	Revised Proposal	Current Preferred Plan

The Updated 2015 Plan in this Supplement is named as such because we allowed our updated modeling for this scenario to select Production Tax Credit (PTC)- and Investment Tax Credit (ITC)-priced renewable resources, as a result of the December 2015 extension of these Federal tax incentives. Implementing this change allows for improved comparability of our Current Preferred Plan and our previous filings in this proceeding.

III. CURRENT PREFERRED PLAN

Our Current Preferred Plan proposes a bold energy vision that is centered around four principles:

First, accelerate the transition from coal energy to lower- and zero-carbon resources. Specifically we propose to:

- Achieve a reduction of in carbon dioxide (CO_2) emissions of nearly 60 percent (from 2005 levels) by 2030,
- Cease coal generation at Sherco Unit 2 in 2023 and Sherco Unit 1 in 2026, and
- Advance the addition of substantial renewable generation (1,200 MW by 2020).

Second, preserve regional system reliability. The preservation of system stability will be critical as we make the transition from coal energy to renewables, and we will preserve it by adding natural gas to our system and by continuing to operate our carbon-free nuclear fleet. We therefore propose to:

- Reaffirm our commitment to nuclear energy through the current licenses of our existing units,
- Add a combustion turbine (CT) in North Dakota by the end of 2025, and

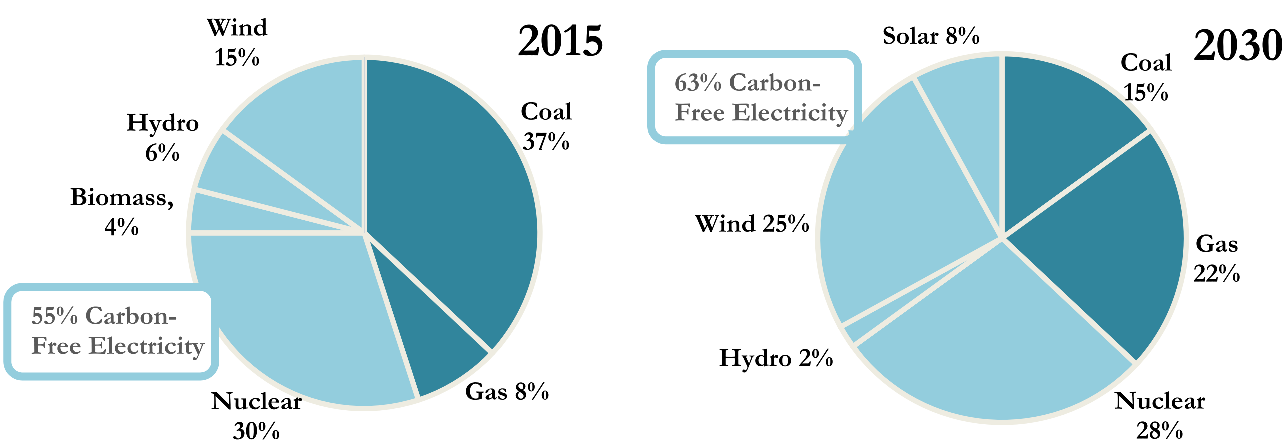
- Replace Sherco generation onsite with a combined cycle (CC) no later than 2026.

Third, pursue energy efficiency gains and grid modernization. We will continue our commitment to energy efficiency and new technologies and look to capitalize on these efforts rather than seeking to replace coal capacity megawatt for megawatt. We believe that modernizing the grid will further enable customer-driven solutions.

Fourth, ensure customer benefits. We will work with our state Commissions, the Minnesota Pollution Control Agency (MPCA) along with its counterpart environmental agencies in our other states, and our stakeholders to ensure our customers get the full benefit of our proposal. Specifically, we will work to maximize the benefits of complying with the Clean Power Plan (CPP) State Plans for our customers and communities.

In short, our vision for the future is cleaner at an affordable price. While our Current Preferred Plan includes slight variations in the timing and siting of our resource additions as compared to the proposal we outlined in our October 2 Reply, the resulting 2030 energy mix is the same. Likewise, the primary resource changes – ceasing coal operations at Sherco Units 1 and 2 and more than doubling the renewable resources on our system – remain unchanged. Figure 1 below provides a side-by-side comparison of our energy mix in 2015 and 2030.

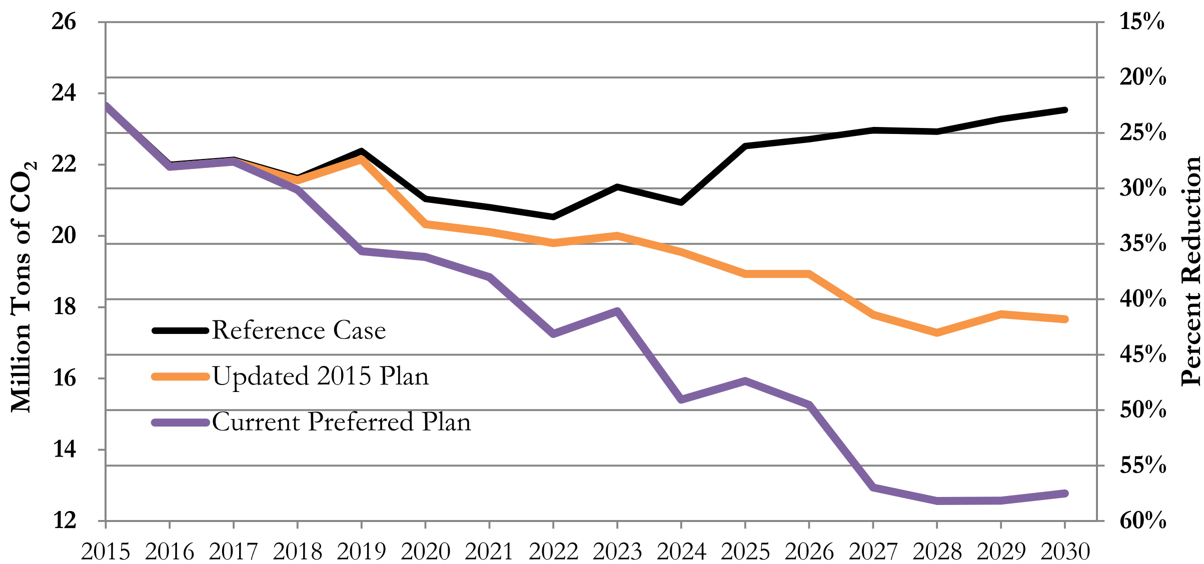
Figure 1: 2015 Energy Mix Compared to Current Preferred Plan in 2030



Our Current Preferred Plan dramatically changes the NSP System energy mix at the end of the planning period. Coal *reduces* from 37 to 15 percent; natural gas *increases* from 8 percent to 22 percent; solar, which makes up less than 1 percent of our energy mix in 2015, *increases* to 8 percent by 2030; wind *increases* from 15 to 25 percent; biomass and hydro *drop* to zero and two percent, respectively (due to contract expirations), while nuclear remains relatively constant at around 30 percent.

While our Updated 2015 Plan would have reduced our 2030 CO_2 emissions 40 percent from 2005 levels, our Current Preferred Plan puts us on an even greater CO_2 reduction trajectory. It will reduce CO_2 emissions by nearly 60 percent from 2005 levels by 2030, and it will move us significantly closer to achieving Minnesota's policy objective of an 80 percent reduction by 2050.

Figure 2: Projected Carbon Reduction from 2005 Levels



As discussed in greater detail below, we will achieve this dramatic reduction for just a fraction of a percent in incremental cost over our Updated 2015 Plan. Figure 2 below compares the projected CO_2 reduction of our Current Preferred Plan to our Updated 2015 Plan and the Reference Case.

It is also important to note that – given what we now know about the final CPP rules – the Reference Case would clearly not comply with the CO_2 reductions required of the Company under Minnesota's state plan to implement the CPP, nor may the Updated 2015 Plan. Further, we believe additional environmental compliance regulations will continue to place pressure on coal operations at Sherco. It is possible that installation of Selective Catalytic Reduction (SCR) equipment for tighter nitrogen oxide (NOx) control might be required near the end of the planning period.[4] We believe the actions we are proposing to take with our Current Preferred Plan positions us well to serve our customers into the future, and reduces the risk of potential future increased costs to maintain environmental compliance.

IV. MINIMUM SYSTEM NEEDS & EXPANSION PLAN

In this section, we discuss our strategy and proposal to address the future capacity deficit that results from our proposal to cease coal operations at Sherco Units 1 and 2, combined with a number of other large changes in our generating resources.

A. Load & Resources Analysis and Future Capacity Deficits

We provide in Table 1 below an updated Load and Resources (L&R) analysis that reflects our excess/deficit capacity position for the planning period, starting with the approved and existing resource additions reflected in our March 2015 Supplement. It also addresses the impact of the resource changes we propose as part of our Current Preferred Plan and summarizes our resulting capacity position through the planning period. Consistent with our January 2015 initial filing and all subsequent filings, we have used the same fall 2014 load forecast in this analysis, and maintained the same available resources to the Strategist model.

[4] In January 2016, the Eighth Circuit issued an opinion that upheld EPA's approval of the Minnesota regional haze plan, which did not require installation of SCRs on Sherco Units 1 and 2. The next regulatory developments that could include a requirement to install SCRs on these units will occur in the early 2020s, with installation potentially required in the late 2020s. The ozone standard, if made more stringent in 2020, might drive SCR installation in the 2027-2032 timeframe. The next round of regional haze planning is expected to occur in the early 2020s (EPA has announced plans to delay the 2018 deadline by 2-3 years), which could drive SCR installation in the late 2020s. We estimate that the capital cost for the installation of an SCR is approximately $250 million per unit in 2015 dollars.

Table 1: Updated Load and Resources (MW UCAP[5])

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Forecasted Load	9,442	9,525	9,597	9,649	9,674	9,694	9,754	9,748	9,766	9,798	9,868	9,962	10,136	10,151	10,251
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Load	8,970	9,048	9,117	9,167	9,190	9,209	9,266	9,261	9,278	9,308	9,375	9,464	9,629	9,644	9,739
MISO Planning Reserve	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
Obligation	9,607	9,691	9,764	9,818	9,843	9,863	9,924	9,919	9,937	9,969	10,041	10,136	10,313	10,328	10,430
Existing/Approved Resources	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load Management	1,009	1,021	1,033	1,044	1,056	1,067	1,078	1,090	1,101	1,103	1,098	1,094	1,089	1,085	1,080
Coal	2,372	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395
Nuclear	1,648	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643
Natural Gas	3,451	3,476	3,476	3,465	3,465	3,465	3,465	3,465	3,137	2,824	2,298	2,047	1,812	1,812	1,812
Black Dog 6	0	0	0	208	208	208	208	208	208	208	208	208	208	208	208
Calpine MEC2	0	0	0	278	278	278	278	278	278	278	278	278	278	278	278
Biomass/RDF/Hydro/ Wind	1,341	1,339	1,316	1,279	1,205	1,437	1,430	1,383	1,310	461	451	407	318	300	299
Solar (1)(3)	25	33	137	143	149	156	164	174	187	202	220	242	268	300	338
Aurora (3)	0	0	70	69	69	69	68	68	68	67	67	67	66	66	66
Community Solar Garden - Additions (2)(3)	20	36	53	72	94	103	103	102	102	101	101	100	100	99	98
Resources – Existing & Approved	9,866	9,942	10,122	10,597	10,562	10,821	10,833	10,806	10,427	9,282	8,758	8,479	8,177	8,186	8,218
Capacity Excess/ Deficit March 16, 2015 Filing	**260**	**251**	**358**	**779**	**719**	**958**	**909**	**887**	**490**	**-687**	**-1,282**	**-1,657**	**-2,136**	**-2,143**	**-2,212**

(1) Solar includes 2014 Solar RFP (Docket No. E002/M-14-162)

(2) Solar Additions represent the revised solar implementation due to Community Solar Gardens.

(3) Solar resources may be accredited up to 1 year earlier than forecasted based on changes to MISO's Business Practices for 2016/2017. This recent proposal has not been incorporated into the current L&R.

Current Preferred Plan – Existing Resource Changes	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sherco 2 Cease Coal Operation	0	0	0	0	0	0	0	-667	-667	-667	-667	-667	-667	-667	-667
Sherco 1 Cease Coal Operation	0	0	0	0	0	0	0	0	0	0	-694	-694	-694	-694	-694
Proposed Coal Changes	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-667**	**-667**	**-667**	**-1,361**	**-1,361**	**-1,361**	**-1,361**	**-1,361**
Capacity Excess/Deficit Jan 29, 2016	**260**	**251**	**358**	**779**	**719**	**958**	**909**	**220**	**-177**	**-1,354**	**-2,643**	**-3,017**	**-3,497**	**-3,503**	**-3,573**

The "Capacity Excess/Deficit March 16, 2015 Filing" line in Table 1 represents our updated capacity position before adding any of the resource changes proposed in our Current Preferred Plan. Consistent with our March 2015 Supplement and our October 2015 Reply, it shows we expect to have sufficient capacity to meet our customers' needs through 2024. However, beginning in 2025 our capacity position shifts from a surplus of nearly 500 MW to a deficit of over 2,200 MW by 2030. Much of this shift is due to the retirement of approximately 800 MW of peaking plants, as well as the expiration of nearly 1,700 MW of hydro and natural gas Power

[5] MISO Unforced Capacity values, summer ratings.

Purchase Agreements (PPAs) during the period, including the expiration of our existing 850 MW PPA with Manitoba Hydro in 2025.

The "Capacity Excess/Deficit Jan 29, 2016" line represents our position after applying the changes to existing resources that are part of our Current Preferred Plan.[6]

B. Current Preferred Plan Expansion Plan

Our Current Preferred Plan proposes to address the capacity deficit through a combination of renewable resource additions in the early years, and the addition of natural gas CT and CC units. In summary, our proposed resource additions are:

- 1,400 MW of large solar additions, including 400 MW by 2020,
- 1,800 MW of additional wind, including 800 MW by 2020,
- A 786 MW CC addition at the Sherco site in 2026 to replace the capacity of Sherco Unit 1 before it ceases operation,
- A 230 MW CT located in North Dakota by the end of 2025, and
- Over 1,800 MW of additional CT capacity.

The early renewable energy additions in our Current Preferred Plan will allow us to capitalize on favorable market pricing associated with the recently extended Federal ITC and PTC tax incentives, reducing the cost impacts of our Current Preferred Plan.

Our modeling results, described in more detail below, consistently show the addition of a CC in 2027.[7] We propose to locate the CC at Sherco because it will allow us to cost-effectively address the transmission issues identified by the Midcontinent Independent System Operator (MISO) Attachment Y2 Study, ensure the stability and reliability of our transmission system, mitigate impacts to the local community and our employees, and potentially provide improved access to natural gas supplies for communities in central Minnesota.

[6] Unit retirements typically occur during a period of the three to nine months following the summer peak (months October-May). Commercial operation of replacement generation would commence between the months of October and March to maintain adequate capacity resources to meet MISO obligations.
[7] 2027 represents the year the CC resource is needed to address a capacity deficit; our Current Proposed Plan proposes that a replacement CC unit go in-service at Sherco such that there will be no gap in MISO capacity accreditation.

In order to balance the perspectives of the stakeholders in the states we serve and maintain the benefits of an integrated system for all of our customers, we also propose to add a CT near our North Dakota load. This would address the reliability concerns of the North Dakota commission, while preserving the objective of both the North Dakota and Minnesota commissions for the Company to develop cost-effective generation proposals.

We show the resource additions we propose with our Current Preferred Plan in Table 2 below.

Table 2: Current Preferred Plan Expansion Plan[8] (MW ICAP[9])

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	-	200	-	200	100	100	200	100	100	-	400	-	-	1,400
Wind	-	-	-	-	800	-	-	400	-	-	400	200	-	-	-	-	1,800
CT	-	-	-	-	-	-	-	-	-	-	460	690	230	230	-	230	1,840
Fargo CT	-	-	-	-	-	-	-	-	-	-	230	-	-	-	-	-	230
Sherco CC	-	-	-	-	-	-	-	-	-	-	-	-	786	-	-	-	786

Note: Resources are shown in their first full year of operation and will go into service the year prior.

We note that, with respect to solar, only the utility-scale resource additions proposed as part of our Current Preferred Plan are identified in this Expansion Plan. All small solar and previously-approved large solar resources are included as available resources in the L&R in Table 1 above. We discuss an update to our *small* solar forecast in Attachment B to this Supplement. To the extent small-scale solar additions out- or under-pace our updated small solar forecast, we will make corresponding adjustments to our large solar acquisition plan.

For reference, we provide updated Renewable Energy Standard and Solar Energy Standard compliance information, as well as the Expansion Plans for the Reference Case and Updated 2015 Plan in Attachment C.

V. RESOURCE PLANNING ANALYSIS

We provide as Attachment B details regarding our revised modeling assumptions, the scenarios and sensitivities analyzed, potential alternatives, an economic analysis,

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[8] We clarify that we do not show the small solar additions, the 187 MW Solar RFP, or the competitive acquisition process resources in our Expansion Plan. These are included as existing/approved resources in the Updated L&R (Table 1).
[9] MISO Installed Capacity values.

a discussion on our treatment of dump energy, and a methodology for our long-term rate impact projections – which we also summarize below.

We analyzed and compared five key scenarios in our analysis. We summarize the assumptions underlying these scenarios in Table 3 below.

Table 3: Summary of Scenarios Analyzed

Scenario Name	Description
Current Preferred Plan	• Ceases operation of a total of 1,400 MW of capacity and associated energy at Sherco Unit 2 in 2023 and Unit 1 in 2026 • Adds 1,800 MW of wind • Adds 1,400 MW of large solar • Includes 700 MW of small solar • All renewable costs updated for Federal ITC/PTC extension • Includes goal of 50 percent ownership of renewables • Adds Company-owned Fargo CT by 2025 and Sherco CC in 2027
Current Preferred Plan – All Generics	Same resource changes as Current Preferred Plan, with all generic thermal replacements
Reference Case	• Continues operation of Sherco Units 1 and 2 through the end of the planning period • Adds 400 MW of wind • Includes 400 MW of small solar additions • Includes 287 MW of large solar additions
Updated 2015 Plan	• Continues operation of Sherco Units 1 and 2 through the planning period • Adds 1,800 MW of wind • Adds 1,400 MW of large solar • Includes 700 MW of small solar • Updated for Federal ITC/PTC extension
North Dakota Plan	No additional renewables beyond currently committed 750 MW of wind; no assumptions changes.

We additionally considered the following alternative scenarios, which we discuss in Attachment B:

- A scenario that converts a Sherco Unit to a Gas Boiler, and
- A scenario that relies only on renewables.

We also discuss Demand Response, Distributed Energy Resources, and Grid Modernization as Alternative Resources in Attachment F.

We evaluate these scenarios holistically by analyzing their environmental performance, strategic flexibility, and cost using a "Run Key" to summarize and compare key Strategist modeling metrics. The Run Key below includes the results of the Present Value Revenue Requirements (PVRR) and Present Value of Societal Costs (PVSC) analysis for each of our key scenarios to provide a reference point, but it also identifies key policy outcome metrics such as the reduction in CO_2 emissions from 2005 levels and the amount of renewable energy added to the NSP System under each scenario. We note that the PVRR and PVSC results are the result of the Strategist model, which extends beyond the planning period to 2053.

Table 4: Run Key[10]

	PVSC Results ($M)	PVRR Results ($M)	2030 Coal Gen vs. Ref Case	2030 Gas Burn (Bcf)	2030 Percent CO_2 Reduction	Total Expansion Plan Renewable Additions (MW)	CPP Compliant?
Current Preferred Plan	$51,293	$45,606	-59%	83	58%	3,200	Yes
Current Preferred Plan, All Generics	$51,280	$45,582	-59%	84	57%	3,200	Yes
Updated 2015 Plan	$51,458	$45,302	-16%	32	42%	3,200	Uncertain
Reference Case	$52,422	$45,605	-	58	23%	400	No
North Dakota Plan	$52,620	$45,473	+3%	68	19%	0	No

The comprehensive Run Key analysis shows that our Current Preferred Plan has the strongest performance in terms of CO_2 reductions and renewable energy additions to the NSP System. The amount of renewable energy additions in our Updated 2015 Plan and Current Preferred Plans are consistent, but the timing and ownership assumptions have shifted. Our Current Preferred Plan continues to provide the best value for our customers – achieving a balance between multiple objectives including reasonable costs, dramatic emissions reductions, anticipated compliance with the CPP, and sustained reliability on our system.

[10] In this Run Key Table, the PVRR Results, change in coal generation in 2030 as compared to the Reference Case (2030 Coal Gen vs. Ref Case), amount of gas burned at our plants in 2030 in Billions of cubic feet (2030 Gas Burn (Bcf)), and the percent reduction of CO_2 from 2005 levels (2030 Percent CO_2 Reduction) are all considered under a cost sensitivity that excludes regulatory costs and CO_2 externalities in the dispatch (Sensitivity T, explained in detail in Attachment B). Under this sensitivity, there will be a tendency to overestimate CO_2 emissions, as coal would be 'priced' at a lower cost and the likelihood of dispatching the resource more frequently would therefore be increased.

A. Modeling Approach

This resource planning process begins the transformation of our generating fleet and signals a step change. It is additionally important to the states in the Upper Midwest Region in terms of alignment and compliance with the requirements of the CPP.

Over the last 20 years, resource plans have traditionally centered on meeting the needs of a growing system, or replacing smaller generators that have reached the end of their lives. In this Resource Plan, we are proposing to cease operation of 1,400 MW of coal generation at Sherco Units 1 and 2, which represents over 30 percent of our baseload generating capacity within the short 2023-2026 timeframe. Because these resources are concentrated in a single geographic area and proximate to other baseload generation, it is important to consider the location of replacement generation. This is a departure from traditional resource planning. In this instance however, the location of new or replacement generation requires additional consideration due to the potential impact to the system of removing such large important assets.

In considering the replacement of key components of an existing system, such as Sherco Units 1 and 2, the analysis must take into account a number of additional considerations that cannot always be captured in economic modeling or analysis terms. These other considerations are both technical and policy-based and include the security and reliability of the combined operation of the generation fleet and the transmission system.

We therefore conducted both traditional "generic" and location-specific Strategist modeling to inform the Current Preferred Plan we propose. We provide an optimized capacity Expansion Plan that considered only generic capacity alternatives as Table 5 below.

Table 5: Generic Unit Expansion Plan (MW ICAP)

Current Preferred Plan - All Generic	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	-	200	-	200	100	100	200	100	100	-	400	-	-	1,400
Wind	-	-	-	-	800	-	-	400	-	-	400	200	-	-	-	-	1,800
CT	-	-	-	-	-	-	-	-	-	-	690	690	230	460	-	-	2,070
CC	-	-	-	-	-	-	-	-	-	-	-	-	778	-	-	-	778

These analyses resulted in the same conclusions in terms of the size and type of expansion resources and nearly identical in their timing. Both the site-specific and generic modeling shows a need for CT capacity in the 2025 timeframe and a CC addition in 2027.[11]

However, as part of the determination to cease coal operations at Sherco Units 1 and 2, we believe it is important and appropriate to also consider the impacts to the transmission system, the local community, state and federal policies, customer and community preferences and cost impacts. We have undertaken numerous studies to better understand these and other implications of our Current Preferred Plan. We believe our plan addresses these issues through our proposal to locate a CT in North Dakota by the end of 2025 and to locate a CC at the Sherco site in 2026 in order meet the capacity deficit resulting from ceasing coal operations at the second Unit.

Table 6 below outlines our capacity surplus/deficit position after applying the proposed resource additions of our Current Preferred Plan.

Table 6: Capacity Position with Current Preferred Plan Expansion Plan (MW UCAP)

Current Preferred Plan Proposed Additions	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Large Solar	0	0	0	0	0	209	261	314	418	471	523	523	732	732	732
Wind	0	0	0	0	0	118	178	178	178	266	266	266	266	266	266
North Dakota CT	0	0	0	0	0	0	0	0	0	219	219	219	219	219	219
Sherco CC	0	0	0	0	0	0	0	0	0	0	0	763	763	763	763
CT	0	0	0	0	0	0	0	0	0	439	1,097	1,316	1,535	1,535	1,755
Total Plan Additions	**0**	**0**	**0**	**0**	**0**	**328**	**439**	**491**	**596**	**1,365**	**2,105**	**3,087**	**3,516**	**3,516**	**3,735**
Revised Proposal Capacity Excess/ Deficit	**260**	**251**	**358**	**779**	**719**	**1,286**	**1,348**	**1,379**	**419**	**11**	**156**	**70**	**19**	**12**	**162**

As shown above, our resulting capacity position is a surplus through the planning period. In 2025 and beyond, our position reflects the expiration of significant capacity resource PPAs and peaking retirements we discussed above, resulting in our more narrow capacity position in the out-years of the planning period. Because

[11] The Department noted in its November 6, 2015 Comments that the Updated 2015 Plan we filed in our initial January 2015 filing and March 2015 Supplement did not include the addition of a CC resource prior to 2030. We note that at the time of those filings, we had not proposed to cease operation of any major generating units in the planning period like we now propose with Sherco Units 1 and 2. Ceasing coal operations of Sherco Units 1 and 2 results in the loss of nearly 1,400 MW of high-capacity-factor generation, which drives our need to add a CC resource prior to 2030. The model selects a natural gas CC unit in 2027 as a cost-effective resource addition to fill this gap. In addition to the favorable economics of adding a CC instead of a CT, at the time the second Sherco Unit ceases coal operation, we must also consider the technical system benefits the Sherco Units provide through their spinning mass to help maintain system reliability. We would not expect a simple-cycle CT to be online very often – nor would that be cost-effective as compared to a CC.

these changes will occur in the out-years, we can continue to monitor our position over time and through the course of upcoming resource planning cycles. Addressing any potential necessary resource additions to meet capacity needs in the mid to late 2020s will be analyzed in our next Resource Plan filing, which we expect to occur by 2018.

B. Locational Analysis

As we have discussed, Resource Plans typically do not analyze location-specific alternatives. However, we believe that our Current Preferred Plan – as well as state and federal policies – present unique challenges that are not easily addressed through a traditional resource planning framework. Sherco Units 1 and 2 are critical components of our energy supply and the Upper Midwest grid. In addition to the energy and capacity they provide to customers, the sheer mass and operating characteristics of these Units provide important system benefits that impact customer reliability. For these reasons, and because the maintenance of system reliability is critical to serving the public interest, a location-specific analysis is essential. With respect to the CT needed in 2025, our North Dakota regulators have stated a preference, and the Company has agreed, to have dispatchable generation located close to our largest load centers in North Dakota, which we discuss in part 3 below.

In order to examine various aspects of the technical and policy-based issues associated with Sherco Units 1 and 2, we undertook several studies to understand the impacts of ceasing coal operations at Sherco Units 1 and 2. The studies we conducted to examine the implications of potentially ceasing coal operations at Sherco Units 1 and 2 are as follows: (1) a MISO Attachment Y2 Study, which assessed grid implications if Units were no longer operating; (2) an Xcel Energy Transmission Reliability Study, which assessed grid implications of replacing all or a portion of the Units' capacity at other locations on the NSP System; (3) a Black Start Plan Analysis that assessed the implications associated with altering our system restoration path and would be necessary because the Units currently play an essential role in the event of a major system outage; and (4) a socioeconomic analysis conducted by the Leeds School of Business at the University of Colorado Boulder and the Labovitz School of Business and Economics at the University of Minnesota Duluth.

We discuss each of these location-specific resources below.

1. *On-Site Combined Cycle Unit at Sherco*

First, we are proposing to construct a 786 MW (ICAP) natural gas CC onsite at the current Sherco site. Because we are not replacing all of the MWs that result from ceasing coal operations at Units 1 and 2 with the CC unit, there will be additional interconnection injection capabilities at the site, which we are proposing to partially utilize by also constructing photovoltaic (PV) solar generation on existing property.[12]

As outlined in Attachment B, our updated modeling for this Supplement includes several options for a CC: (1) at the site of the current Sherco 1 and 2 Units, (2) at a generic brownfield site, and (3) at a generic greenfield site. We developed the option of onsite replacement to incorporate into our Strategist modeling an economic analysis of locating generation at the Sherco site. We believe there are significant benefits associated with siting the CC at the Sherco site, which we discuss below.

a. Benefits of Onsite Generation at Sherco

There are number of benefits to locating a replacement CC at the Sherco site. Importantly, our Strategist demonstrates that the addition of a CC unit onsite at Sherco is part of a least-cost capacity expansion plan. However, not all relevant factors are easily converted to an economic basis for inclusion in Strategist. For instance, there are benefits to using existing infrastructure and an existing brownfield site that do not easily reduce to economic terms, including the fact that the transmission grid has been studied, designed, engineered and operated for decades to provide a high degree of reliability and resiliency for customers by incorporating significant generation injection at the Sherco site. Similarly, it is important to consider that our host community of Becker, Minnesota and the greater Sherburne County area has come to depend on local employment opportunities, property taxes, and other economic benefits associated with the existing units. We discuss these factors below.

Use of Existing Infrastructure. As an existing brownfield generation site, the Sherco site offers a number of advantages over new greenfield sites, both in terms of operations and cost. For example, we can use our existing interconnection rights and existing substation and transmission outlet capacity once Units 1 and 2 cease

[12] We have identified two areas on the existing Sherco site for solar development. One location would be atop the closed and capped ash ponds 1 and 2 and the second would be on open land on the north side of the Mississippi River between the Sherco plant and the Monticello plant.

coal operations. The existing Sherco site also comprises sufficient available land to site a CC unit and is already permitted for a large industrial generating facility. Further, existing water and wastewater treatment facilities can support the proposed CC unit, and existing facility staff, administration, warehousing, and maintenance facilities can likewise be utilized. Finally, the site's water allocation is sufficient for cooling approximately 2,300 MW of generation (the current combined installed capacity of Sherco Units 1, 2 and 3), which means that once Units 1 and 2 cease coal operations, an allocation equivalent to approximately 1,400 MW will become available. Consequently, portions of the Unit 2 cooling system can be reused by the new CC facility, allowing the replacement CC at the Sherco site to be wet-cooled, improving both performance and cost.

The System is Designed to Reliably Operate with Significant Generation Injection at Sherco. From the technical studies conducted by MISO and the Company we concluded that we can avoid anticipated impacts on the electric transmission system and related costs by replacing generation at Sherco. In contrast, siting replacement thermal generation at other locations on the NSP System have disadvantages compared to siting a CC at Sherco, including a significant level of uncertainty with regard to final costs and performance. The *Xcel Energy Transmission Reliability Study* confirmed that the existing transmission system with significant generation injection at Sherco works well, and plays a significant role in providing reliable service for NSP System customers and other customers in our portion of the MISO region. It also concluded that there are transmission upgrade costs and other trade-offs associated with replacing Sherco Units 1 and 2 at an alternative location, such as increased energy losses the farther the replacement generation is located from the Twin Cities load center.

Unlike an onsite CC that will have injection capability and interconnection rights, replacement generation at other locations will be subject to the MISO generator interconnection process, and may incur additional network upgrade costs beyond those we have identified. The MISO interconnection queue has changed significantly since these technical studies were initiated in early 2015. Since March 2015, requests to add nearly 10,000 MW of wind have entered the queue in the Iowa, Minnesota, North Dakota, and South Dakota area.[13] Nearly 70 percent, or 7,000 MW have paid all required study deposits and achieved milestones, qualifying them to participate in MISO's upcoming interconnection studies. This significant

[13] MISO Generator Interconnection Queue is located at: https://www.misoenergy.org/Planning/GeneratorInterconnection/Pages/InterconnectionQueue.aspx.

number of projects that have entered MISO's interconnection queue creates uncertainty with respect to the identified transmission impacts and associated interconnection costs. Replacement generation at the Sherco site, as we have proposed, has the added benefit of not being impacted by this uncertainty.

Locating a CC at the Sherco Site Avoids Significant Transmission Costs. Our technical studies each identified costs associated with siting replacement generation at locations other than Sherco. We summarize the study results below and provide a full summary of the studies and our conclusions as Attachment D.

MISO Y2 Study. MISO concluded that retirement of Sherco Unit 1 and Sherco Unit 2 would result in violations of applicable planning criteria that would require transmission upgrades and the need for Units to be designated as System Support Resources (SSR). Assuming a future Attachment Y study would have similar results, MISO would require that the identified violations be mitigated to its satisfaction prior to retirement of Sherco Units 1 and 2, if replacement generation is not located at Sherco. Specifically, the MISO Y2 study identified significant thermal and voltage violations in the Twin Cities if Sherco Units 1 and 2 are retired. The voltage violations impact our Monticello Nuclear Plant's operation and Nuclear Regulatory Commission (NRC) requirements. Both the thermal and voltage violations would need to be addressed through transmission investment in the Sherco area, regardless of the location of any replacement generation at an alternative site before the units could cease operation. Additional transmission upgrades that may be necessary due to the location of replacement generation, were not within the scope of the MISO Y2 study, but were studied in the Xcel Energy Transmission Reliability Study we discuss below. We provide this study report as Attachment D1.

Xcel Energy Transmission Reliability Study. Our study, conducted in conjunction with Siemens Power Technologies International, involved a full thermal analysis, full voltage analysis, and transient stability analysis. As noted above, it confirmed that the existing transmission system with significant generation injection at Sherco works well, and that there are transmission upgrade costs and other trade-offs associated with replacing Sherco Units 1 and 2 at an alternative location. We provide these study reports as Attachments D2 and D3.

Black Start Plan Analysis. Our analysis of our current Black Start Plan examined impacts if our current Sherco Units 1 and 2 target units cease coal operations.[14] Our analysis concluded that our proposal to construct a natural gas CC unit at the Sherco site would provide for use of the current and most efficient restoration path. Altering the restoration path away from the Sherco site will require the addition of various equipment and/or facilities and results in a longer restoration period, which is of greatest concern in winter/cold months. We have included the approximate costs of altering our restoration path as part of the costs associated with siting the 2027 CC at alternative locations.

If replacement generation is not sited at Sherco, we must mitigate the reliability issues our technical studies identified. For example, the Monticello Plant cannot operate if its voltage is outside the permissible range. As discussed further in Attachment D, we have determined that the best option to address these issues is to convert Sherco Unit 1 or Unit 2 to a Synchronous Condenser (SC). Importantly, SCs provide not only the required continuous range of voltage support, but are also a rotating mass that helps hold the grid electrically together following a disturbance such as a major fault. These additional costs stem from transmission upgrades and the need for additional equipment onsite at Sherco and other locations on the NSP System. We refer to these costs as "leave-behind" costs, which are therefore appropriately added to the cost of any combined cycle generator at an alternative location. The total leave-behind costs are shown below in Table 7.

[14] A Black Start Plan specifies the process of restoring the grid to full operation without relying on the external transmission network following a full or partial black out. Black Start Plans are required by the North American Electric Reliability Corporation (NERC), developed in concert with neighboring utilities, and are subject to review and approval by MISO.

Table 7: Leave-Behind Costs – PVRR
($Millions – 2015)

Cost Components	PVRR
	[TRADE SECRET BEGINS…
Installation of Synchronous Condenser	
O&M for Synchronous Condenser	
Upgrade Brainerd - Riverton 115 kV Line	
Rebuild Helena - Scott County 345 kV Line	
Installation of Additional Capacitors	
New Blackstart Path	
	…TRADE SECRET END]
Total	**$150**

Retiring Sherco Units 1 and 2 would have negative impacts on employment, GDP, and disposable personal income in Sherburne County. We understand the Commission has previously expressed interest in understanding the socioeconomic impacts on the Becker area, so therefore commissioned a socioeconomic study. We summarize the study below and provide a full summary and the study itself as Attachments G and G1, respectively. This Study assessed impacts on employment, Gross Domestic Product (GDP), and disposable personal income on the locations impacted by a change in operating expenditures, capital expenditures, property taxes, and electricity rates resulting from Unit retirement and replacement at an alternative location. The scenarios analyzed in the Study, included various potential Unit retirement dates and a scenario that included the replacement of the two Sherco Units with one CC at the Sherco site and one CC located in Dakota County. The Study found that all early retirement scenarios, when compared to a baseline where the Units continued operations through the planning period, result in moderately slower growth in the Minnesota economy. The closure of the Units showed negative impacts on employment, GDP, and disposable personal income in Sherburne County. However, if the generation is replaced elsewhere in Minnesota, those impacts are partially offset by positive economic impacts in the replacement location – mitigating on an overall state-level, the negative impacts. While the Study did not model a scenario that directly reflects our Current Preferred Plan, our proposed 2023 and 2026 dates fall within the range of scenarios analyzed.

As we stated in our October 2, 2015 Reply, ceasing coal operations at Sherco Units 1 and 2 will impact our employees and their families, the City of Becker and surrounding area, and Liberty Paper, which relies on steam from the Units for its operations. Charting a path certain for these stakeholders particularly, will provide an 8-10 year transition period, and with our proposal to site replacement generation onsite, will promote economic development, and reaffirm our commitment to central Minnesota. We are committed to mitigating impacts on our employees by working closely with our International Brotherhood of Electrical Workers union local to successfully manage the transition. Finally, our proposed onsite CC will provide additional options to continue to supply steam to Liberty Paper, who is a valued Xcel Energy customer, an important employer in the Becker area, and a critical part of Minnesota's recycling industry.

b. Costs of Onsite CC

Generating Equipment. We developed the costs for the onsite CC generation based on the installation of a 2x1 CC wet-cooled facility in 2026, which would begin commercial operation prior to the second Sherco Unit ceasing coal operations. The summer-rated capacity of the CC facility would be approximately 763 MW UCAP (786 MW ICAP). We developed our initial capital cost estimates for the onsite Sherco CC by adjusting the cost of the generic CC used in the modeling throughout this proceeding for the site-specific benefits associated with utilizing existing infrastructure. Because of the site's available water allocation, the replacement CC at the Sherco site is to be wet-cooled, improving both performance and cost. We expect the initial capital cost of the generic CC to be approximately **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** higher than our proposed onsite CC at Sherco.[15]

Because we have not obtained formal estimates for the turbine equipment or performed detailed engineering, we have developed delta cost estimates in order to compare the unique attributes of locating a CC onsite and at alternative locations. The ultimate project pricing will vary based on the final design definition, equipment price negotiations, contractual commercial terms, and other factors.

[15] 2015 dollars on a PVRR basis. We use the same Fixed Operating and Maintenance (Fixed O&M) costs and on-going capital costs as the generic CC alternative.

Natural Gas Infrastructure. Our proposed CC unit at Sherco will be fueled entirely by natural gas. Even though the community of Becker enjoys the benefits of heating their homes and commercial businesses with natural gas from Xcel Energy, there is not currently adequate pressure and capacity with the existing natural gas infrastructure to serve a new CC unit.

Therefore we performed a high-level cost analysis of bringing new natural gas infrastructure to serve the proposed CC unit at Sherco, so as to estimate a gas demand charge, which we estimate to be approximately **[TRADE SECRET BEGINS…**
… TRADE SECRET ENDS] to the Sherco site. We based this estimate on our experience in designing, engineering, and constructing competitive natural gas infrastructure, which we do through the use of a competitive bidding process for each component or phase of the construction process. We also benchmarked the costs of some of our past significant, similar construction projects within the industry to ensure that our estimates are in-line with other contractors. We will leverage our knowledge, expertise, and competitive advantage to minimize costs for our customers. We note that we are also assessing opportunities arising from the new natural gas infrastructure that may afford numerous adjacent Minnesota communities along the proposed route greater access to a natural gas supply.

In determining the cost to construct the natural gas infrastructure, there are two primary aspects to consider: (1) the cost of the facilities from the source of supply to the new market (in this case, Sherco); and (2) the costs from the source of the supply, to ensure the new infrastructure has adequate pressure and capacity. We evaluated several alternatives to determine the best way to source the new supply to Sherco.

The associated capital cost estimates incorporated into our modeling are indicative. The cost estimates we provide for this analysis are based on current system constraints and associated capital construction project costs required to alleviate those constraints, which are subject to change. We believe however, they are reasonable and appropriate for planning purposes.

Transmission Infrastructure. As discussed above, because the new CC unit can use existing transmission interconnection rights, there will not be any associated network upgrade costs. Generators located at other locations would have to go through the MISO generator interconnection process in order to obtain interconnection rights, and may additionally incur transmission upgrade costs. We estimate onsite substation modifications to cost approximately **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**. We note that we are proposing a 786 MW CC unit, which is below the current 1,400 MW capacity and associated energy output of Sherco Units 1 and 2. We also intend to locate a portion of the proposed solar resource additions at the Sherco site.

We outline the cost deltas from a generic CC on a PVRR basis below.[16] This approach allows us to show the site-specific costs associated with locating a CC at the Sherco site and to compare the site-specific costs of onsite replacement to alternative site locations.

Table 8: Site-Specific Cost Comparison – Onsite CC Replacement ($Millions – 2015 dollars)

[TRADE SECRET BEGINS…

PVRR Delta from Generic Unit	
Site Specific PVRR Costs	
Transmission Facilities[17]	
Gas Demand Charge	
…TRADE SECRET ENDS]	
Total	***$155***

2. Alternatives to Retirement and Onsite Replacement

We considered several alternatives to our proposed partial replacement of the Sherco Units with an onsite CC generating unit. In addition to examining another brownfield site and a greenfield site, we explored alternatives such as all renewables and alternative resource such as Distributed Energy Resources, Demand Response, and grid efficiencies. We discuss the brownfield and greenfield alternatives below and the renewables and alternative resources in Attachments B and F, respectively.

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[16] All costs have been discounted to 2015 dollars. Actual costs will be influenced by the year in which they are incurred. Therefore, in order to compare these estimates with future expenditures, these estimates must be escalated.
[17] The substation modification costs noted above are included in the delta from the generic unit.

Our Current Preferred Plan does not propose to replace all of the Sherco Units 1 and 2 capacity with gas-fired generation. As explained in our October Reply, we are committed to reducing the CO_2 emissions of the NSP System and advancing the acquisition of significant levels of renewable generation. Thus, we plan to acquire significant amounts of wind and solar resources to help meet our future energy and capacity needs. Below we discuss alternatives to replacing the Sherco Units with an onsite CC, in conjunction with additional renewable generation.

a. Offsite Brownfield CC

The Offsite Brownfield CC alternative included in our updated modeling is based on representative costs associated with locating a CC at the existing Black Dog site in Burnsville, Minnesota. Black Dog coal-fired Units 3 and 4 were suspended in early 2015, and the coal and ash storage and handling areas are currently being remediated and closed. When this work is complete, there will be sufficient land area protected from the 100-year flood plain to construct a 2x1 CC facility and 345 kV switchyard. The Twin Cities 345 kV ring is nearby – approximately just one-half mile from the plant site – and could be used as the transmission outlet from the new facility, making this site an appropriate proxy for an off-site brownfield CC.

Current information indicates that a new 345 kV substation would be required to accommodate the installation of this CC Unit. However, as noted above, additional transmission upgrade and interconnection costs could be incurred through the MISO generator interconnection process. Gas costs for this facility are based on anticipated demand charges for use of the Northern Natural Gas (NNG) system. The site has significant water allocations and would be able to support a wet-cooled CC facility through conversion of the existing Black Dog facility from a once-through cooling system to a cooling tower system.

Similar to the onsite Sherco alternative, locating generation on a brownfield site results in savings related to transmission upgrades, gas infrastructure, and other existing infrastructure such as land, access to water supplies, and existing maintenance facilities and facility staff.[18] As we did for the onsite CC alternative, we have adjusted the generic CC cost to incorporate the advantages of a brownfield location. However, this analysis must include the costs to mitigate the loss of

[18] While the Brownfield site is located near existing transmission facilities, the availability of interconnection capacity is uncertain until the MISO interconnection process is complete.

generation at the Sherco site. Table 9 below summarizes the cost deltas from a Generic CC in the representative Offsite Brownfield CC alternative:

Table 9: Site-Specific Cost Comparison – Offsite Brownfield Alternative ($Millions – 2015 dollars)

	Brownfield Alternative	Sherco CC
	[TRADE SECRET BEGINS…	
PVRR Delta from Generic Unit		
Site Specific PVRR Costs		
Leave-Behind Costs		
345 kV Interconnection Facilities		
Annual Gas Demand Charge		
		…TRADE SECRET ENDS]
Total	***$221***	***$155***
PVRR Delta from Sherco Site	**$66**	

The Offsite Brownfield CC results in approximately $66 million in additional costs as compared to siting the CC at Sherco. In addition, locating the replacement CC offsite results in greater risk of additional transmission expense and reliability impacts, and does not consider the important economic benefits of replacing generation at the Sherco site, nor the potential of expanding access to natural gas supplies to residents of central Minnesota.

b. Offsite Greenfield CC

We also included an Offsite Greenfield CC alternative in our updated modeling. The Greenfield site is based on a location in Western Minnesota near existing transmission and interstate natural gas lines. Water resources are limited, and it is expected that such a facility would have to be dry-cooled to minimize water use. We have evaluated the costs for transmission interconnection and upgrades and natural gas infrastructure, and included those costs in our analysis. As noted above, additional transmission upgrade and interconnection costs could be incurred through the MISO generator interconnection process. Gas costs for this facility assume construction of new infrastructure. Table 10 below summarizes the costs included in the representative Offsite Greenfield alternative:

Table 10: Site-Specific Cost Comparison – Offsite Greenfield Alternative ($Millions – 2015 dollars)

	Greenfield Alternative	Sherco CC
	[TRADE SECRET BEGINS…	
PVRR Delta from Generic Unit		
Site Specific PVRR Costs		
Leave-Behind Costs		
345 kV Interconnection Facilities		
Annual Gas Demand Charge		
		…TRADE SECRET ENDS]
Total	***$172***	***$155***
PVRR Delta from Sherco Site	**$17**	

The Offsite Greenfield CC results in approximately $17 million in additional costs as compared to siting the CC at Sherco. The Offsite Greenfield alternative is a CC located along the Brookings 345 kV line, so will use available transmission outlet capability that could otherwise be used for renewables in the wind-rich western and southwestern areas of Minnesota, which may increase transmission upgrade costs for those types of facilities during the planning period. These costs are difficult to quantify, but could be significant. As with the offsite brownfield alternative, locating the replacement CC offsite results in greater risk of additional transmission expense and reliability impacts, and does not consider the important economic benefits of replacing generation at the Sherco site, nor the potential of expanding access to natural gas supplies to residents of central Minnesota.

c. Conclusion

The addition of a CC at the Sherco site is a critical part of our proposal to cease coal operations of Sherco Units 1 and 2 and ensure reliability at a reasonable cost to ratepayers. By locating a CC at Sherco, we eliminate the need to address the issues identified in the MISO Y2 Study, avoid the costs associated with locating the CC offsite, support economic development in the Becker area, and mitigate reliability risks and implications stemming from the shutdown of two of the largest baseload generating units in the Upper Midwest. Our Strategist analysis, transmission studies, and socioeconomic studies support this proposal, and we believe it best advances the interest of our customers, as well as the Becker economy and our employees.

3. *North Dakota Combustion Turbine*

a. Policy Considerations

Our regulators in North Dakota have stated that they believe it would be in the best interest of our customers to have cost-effective, dispatchable generation located in North Dakota and close to major load centers in that state. In an effort to balance the interests of the states that we serve and to maintain the benefits of an integrated system for all of our customers, the Company set out to find CT options that address the reliability concerns of the North Dakota commission, while preserving the Company's desire to develop cost-effective generation alternatives. To that end, we embarked on a review of possible generation sites located reasonably close to Company load centers in North Dakota that could also satisfy traditional resource planning criteria. We discuss the results of that review below.

b. Alternative Sites

In our review, we identified two potential areas where a CT could be located that satisfies the common desires of Minnesota and North Dakota commissions for a selection of a cost-competitive and reliable generation resource. The two locations include an area west of Fargo (Fargo CT) and a location in the south-central portion of North Dakota (South Central CT). These two sites appear to satisfy the traditional resource planning criteria, while also aligning policies regarding energy security, reliability, and energy policy objectives.

Recognizing that the Company is the largest utility in North Dakota, and that the Company does not yet have any dispatchable generation (either owned or in the form of a PPA) in that state, we decided to start the search for potential generation sites with a focus on North Dakota. While a formal project development and engineering estimate has yet to begin, it appears that both sites have adequate access to natural gas supplies and transmission injection capacity as well as available land and workforce.[19]

We also looked at alternative locations in Minnesota and Wisconsin. The potential site in Minnesota included the development of a second CT at our existing Black

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[19] While generators at both sites would be required to go through the MISO generation interconnection process, a CT has an advantage over a CC as it is a peaking resource and will only be studied on-peak where we believe significantly more transmission capacity exists in the locations considered for the alternative CTs.

Dog site. Consistent with the Black Dog 6 CT that was recently approved by the Minnesota and North Dakota commissions, the Black Dog 7 site takes advantage of an already owned brownfield location with access to transmission and an existing workforce.

While we also identified a possible site for a CT in Wisconsin, we did not perform any additional development work on that site at this time due to the need for more robust transmission studies. While all of the sites in Minnesota also appear to satisfy traditional resource planning criteria, they obviously do not address the concerns about the lack of dispatchable generation near the Company's North Dakota load.

Table 11 below contains a summary table of the key resource planning characteristics of the three locations investigated by the Company.

Table 11: Summary of CT Alternatives

	Fargo	South Central	Black Dog 7
Generator	Generic 230 MW Dual-Fuel CT[20]	Generic 230 MW Gas-Fired CT	Generic 230 MW Gas-Fired CT
Gas Supply	Lateral Gas Pipeline	Lateral Gas Pipeline	Demand Charges on NNG
Transmission	345 kV Interconnection Facilities	345 kV Interconnection Facilities and 230 kV Line Upgrades	345 kV Interconnection Facilities

Since both the Minnesota and North Dakota commissions have a keen interest in determining if the proposed CT alternatives are cost-effective and reliable when compared with other alternatives, we have performed an initial analysis of the three sites identified by the Company. While we have not obtained formal estimates on the turbine equipment or performed detailed engineering on the projects, as with the analysis of CC site alternatives above, we developed delta cost estimates from the generic CT unit used in the modeling. The deltas show the site-specific cost differences for each location based on the unique factors of the generator site, including transmission access, gas supply costs, and operation and maintenance costs. We summarize this cost comparison in Table 12 below.

[20] We are proposing oil back-up at the Fargo site to allow for the unit to have firm accreditation year-round, similar to the Company's Angus Anson Units 2 and 3 in South Dakota.

Table 12: Site-Specific Cost Comparison – CT Alternatives
($Millions – 2015 dollars)

	Fargo	South Central	Black Dog 7
	[TRADE SECRET BEGINS…		
PVRR Delta from Generic Unit			
Site-Specific PVRR Costs			
Transmission			
Annual Gas Demand Charge			
			…TRADE SECRET ENDS]
Total	***$79***	***$106***	***$85***
PVRR Delta from Fargo Site		**$27**	**$6**

This preliminary cost analysis shows that the Fargo CT site is cost competitive to the Black Dog 7 CT project, while the South Central North Dakota CT site is somewhat higher in cost.

4. *Conclusion*

The impact to our customers, reliability, the transmission system, the local community, and state and federal policies are all appropriately considered as part of the determination to cease coal operations at Sherco Units 1 and 2. We have undertaken numerous studies to better understand the implications of our Sherco proposal and believe our Current Preferred Plan addresses these issues in a cost-effective manner. For these reasons, we believe our location-specific expansion plan is in the public interest.

C. Ownership of New Resources

We propose to own the Sherco and North Dakota natural gas plants, along with a portion of the renewable generation additions contemplated by our Expansion Plan. Our ownership of these assets is a critical component of our vision, as it will result in a balanced generation portfolio that will minimize customer costs and mitigate risk of future cost increases. We discuss the specific benefits of ownership in greater detail below and explain how our customers will realize these benefits.

1. *Proposed CC at Sherco Site and CT in North Dakota*

By owning the CC that we propose to add at the Sherco site, we are able to use our existing site and interconnection rights, we will continue to employ current Sherco-based Xcel Energy employees, we will preserve options to continue to supply a large customer with steam, and we will avoid additional cost and risks associated with modifying our Black Start Plan. Our ownership of the CC allows the Company to secure these important benefits for our customers, and we believe it is in the public interest.

Ownership of a CT in North Dakota provides important options to be able to expand generation onsite in the future to serve our customers in the Red River Valley region. Expansion options could include a partnership with another utility or converting the facility to a CC. If a third-party owns the CT, these options may not be available or may be more expensive and difficult to implement. In addition, the North Dakota commission has expressed a preference for an ownership model to a PPA model. Thus, ownership best allows us to provide reliable service to our customers in the region.

2. *Proposed Renewable Resources*

An important and significant component of our proposed plan is the accelerated acquisition of renewable resources. Table 13 below, shows our proposed renewable resource additions during the planning period.

Table 13: Proposed Renewable Additions (MW ICAP)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	-	200	-	200	100	100	200	100	100	-	400	-	-	1,400
Wind	-	-	-	-	800	-	-	400	-	-	400	200	-	-	-	-	1,800

As discussed below, we propose that approximately half of the renewable additions be Company-owned resources, which we have assumed in the Strategist modeling supporting our Current Preferred Plan. A balance between PPA and Company-owned resources ensures that our customers obtain the benefits of each ownership structure, and that the cost and risks are appropriately balanced. Table 14 below shows the renewable additions that we propose to own.

Table 14: Proposed Owned Renewable Additions (MW ICAP)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	-	100	-	100	50	50	100	50	50	-	200	-	-	700
Wind	-	-	-	-	400	-	-	200	-	-	200	200	-	-	-	-	1,000

Table 15 below summarizes our current portfolio of wind resources, which contains approximately two-thirds purchased wind resources and one-third owned resources.[21]

Table 15: Current Wind Generation by Asset Type (MW)

Asset Type	Capacity Type	MW	Percent of Total
Owned	Nameplate	851.5	33%
PPA	Contracted*	1,759.9	67%

** Since we contract for a specific amount of energy, we do not maintain nameplate capacities in our records.*

Our solar portfolio, which primarily includes the Aurora project and the 187 MW resulting from our 2014 RFP is exclusively PPAs and third-party providers.

While we will also continue to acquire renewable resources through PPAs and third-party providers, concentrated efforts to improve the balance of our portfolio through expanded ownership of renewable resources is appropriate and necessary to minimize customer costs and balance risks. In this way, we believe our plan will capitalize on the strengths of each structure while ensuring that resources are acquired at reasonable costs for our customers.

Understanding the customer impacts of utility ownership versus purchased power is important to assessing the benefits of a balanced portfolio. While utility participation in competitive bidding may on its face be a means for such comparison, we have found that it is difficult to obtain an accurate assessment of the full economic and life-cycle costs and other benefits solely through this perspective. We believe a framework that allows the relative costs and benefits of our future acquisition of renewable resources to be assessed is a more reasonable and appropriate approach.

[21] Includes the most recently-approved Odell, Courtenay, Pleasant Valley, and Border Winds projects.

Given similar access to suppliers, sites, and transmission, we also believe it is reasonable to assume that the capital costs of renewable development will be very similar between a utility-owned project and third-party development; thus, customer impacts will stem from the respective cost recovery mechanisms of the projects rather than development costs. Key issues affecting customer costs include differences regarding contract versus asset life and balance sheet impacts. We discuss each of these issues below.

3. Contract vs. Asset Life

Asset life affects the comparative costs of utility-owned versus purchased wind energy. A PPA is for a specific term that is likely shorter than the useful life of the facility. After the expiration of a PPA, the Company must return to the marketplace to procure replacement renewable energy. The market price of this replacement renewable energy will be based on a number of factors, including:

- Costs for new wind and solar generating facilities,
- Costs of capital,
- Market prices for electricity,
- The value of embedded environmental attributes, including Renewable Energy Credits (RECs) and Emission Rate Credits (ERCs) under the CPP, and
- PTC and ITC status and values.

Under utility ownership, by contrast, the asset remains in the utility portfolio until it is retired. Customers benefit when the actual useful life of the asset exceeds a comparable PPA's term, as they will continue to receive the capacity and energy for a longer period of time, lowering lifecycle costs. While we have modeled a 25-year life for both utility-owned and PPA renewable resources, there is the potential that the 25-year PPAs may not be widely available and also that utility-owned assets will exceed a 25-year life.

Based on our 2013 Wind RFP and 2014 Solar RFP, wind projects typically have PPA terms of 15 to 20 years with an asset life of 25-30 years, and solar projects typically have PPA terms of 20 to 25 years with an asset life of 25-30 years. While utility-owned assets may require refurbishment to extend their useful life, we would expect such costs to be lower than the market price of replacement renewable energy that would be required when a PPA expires. Life extension options for utility assets have traditionally offered cost-savings benefits for customers.

The tradeoff for these long-term benefits is that relative to a PPA, utility-owned assets generally have higher costs in the early years when the rate base value is highest. For wind resources, direct pass-through to customers of the PTC will help offset this impact. Although there is no guarantee that ownership will provide significant present value savings compared to a PPA, it is certain that by using only PPAs to meet renewable resource needs, customers lose the opportunity for overall longer-term savings from the value of depreciating plant.

Figures 3 and 4 below illustrate the potential benefits provided by Company ownership of wind and solar resources. Customers could obtain significant benefits as shown by the shaded areas in the below figures.

Figure 3: Benefit Provided by Ownership
Illustrative 200 MW Wind Resource

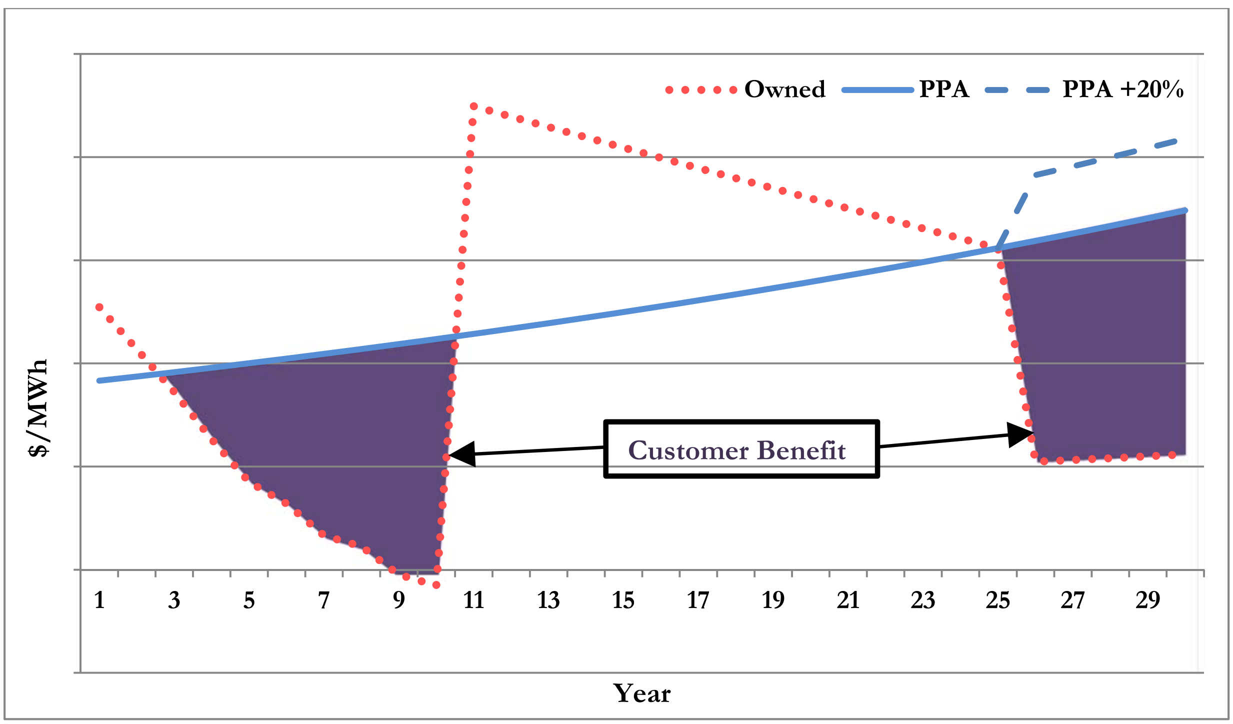
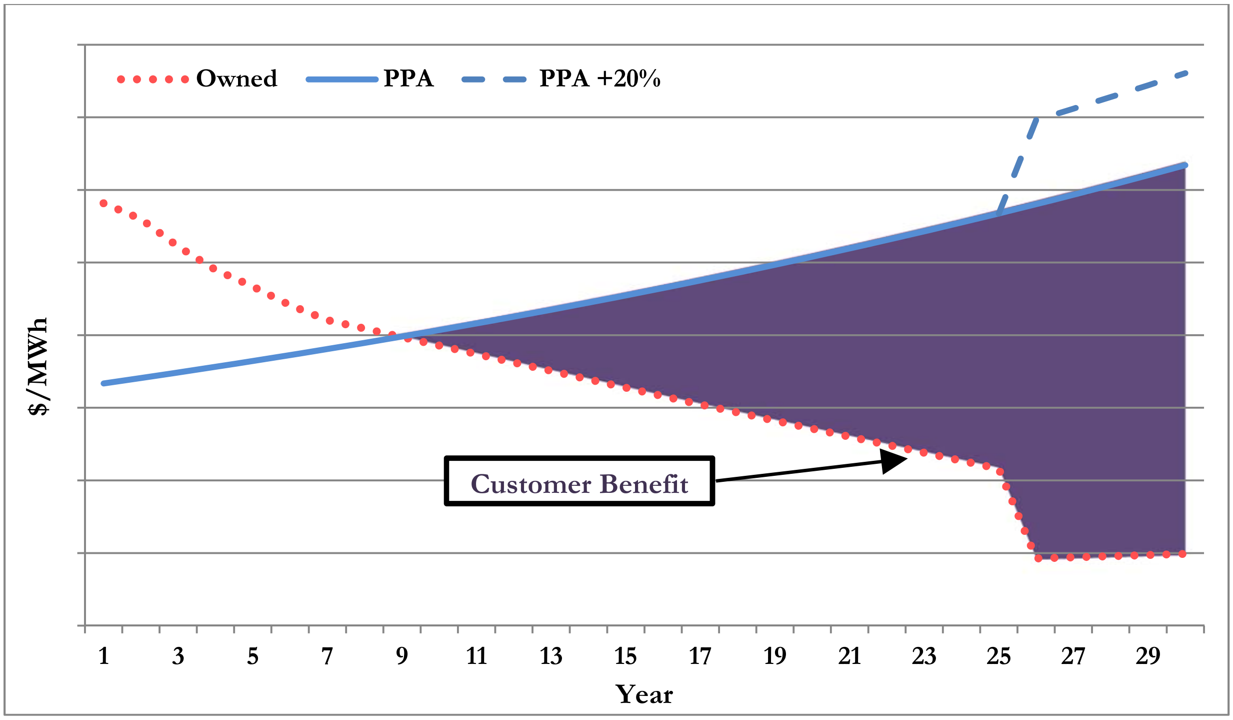


Figure 4: Benefit Provided by Ownership
Illustrative 50 MW Solar Resource



The cost per MWh for the PPA and utility-owned resources were derived from the wind and solar resources included in our modeling which assume a 25-year life. The utility-owned wind resource costs show additional reductions in the first 10 years due to the PTC while the PPA wind costs spread the benefits over the PPA term. The solar resources include the benefits of the ITC. These benefits are not achieved under a PPA structure, as the PPA must either be renegotiated or replaced when the contract term expires. In addition, ownership may help smooth rate impacts as the renewable resources procured in the near term will experience several years of depreciation prior to our projected procurement of significant additional resources in the mid-2020s.

4. *Balance Sheet Impacts*

Debt accounts for approximately half of the Company's total capital structure. The cost of debt is highly dependent on the credit profile of the utility, and higher-cost debt results in higher costs for customers. Generally speaking, companies with higher percentages of debt in their capital structure are considered riskier and pay higher rates for this debt, due to concerns that the company may be over-leveraged.

PPAs are obligations the utility must pay that are viewed as additional debt on the utility's balance sheets – affecting the credit profile of the utility, which in turn affects costs to customers. Credit rating agencies also consider off balance sheet obligations in their risk assessment to determine credit ratings. These agencies impute additional debt to a utility's balance sheets based on the size, type, and terms of PPAs, thus increasing the financial leverage and risk of a company and also its cost of debt.

Likewise, auditors scrutinize PPAs to evaluate the effects of imputed debt and the lease-like characteristics of PPAs to ensure fair representation of obligations and creditworthiness on financial statements. Imputed debt and lease accounting effects have the potential to add significant debt-like obligations to the balance sheet used to determine the credit rating for the Company. In contrast to a PPA, owned projects are financed through both equity and debt which allows us to maintain our capital structure.

These issues highlight some of the implications of PPAs. Imputed debt has the potential to raise costs for customers in one of two ways: (1) through higher debt costs, as already described; and (2) through additional equity costs, as the utility may require additional equity in its capital structure to compensate for the additional debt-like obligations associated with the PPAs. Because these impacts affect the overall capital structure and capital costs, the costs of financing other utility infrastructure requirements are higher than they otherwise would be. While wind and solar PPAs are viewed more favorably than more traditional PPAs due to their energy-based payment structure, they nonetheless have imputed debt implications for the utility that will, over time, raise costs for customers.

Finally, we believe there are additional factors to consider when determining an appropriate balance between owned and purchased assets:

Potential unknown valuable attributes. If and when new value is attached to attributes of renewable resources (such as renewable energy credits were in the past), ownership of resources ensures that customers benefit from those attributes. If the resource is purchased through a PPA, those attributes may not accrue to customers. In the Silent REC Docket, the Commission was presented with this issue.[22] Under a PPA structure, there is uncertainty and risk associated with the allocation of any new valuable attribute that was not anticipated by the PPA. If the resource is utility-

[22] *See* Docket No. E002/M-08-440.

owned, however, our Commissions will have increased control over how the value associated with any attribute is allocated.

Increased diversity in supply portfolio. Our proposed portfolio reflects an appropriate resource mix that achieves compliance with regulatory requirements, such as the CPP, and state policy objectives. Investors would be appropriately concerned if a utility's owned assets did not include the renewable assets required to achieve compliance. Thus, the financial health of the utility can be affected both by the aggregate mix of resources used to supply customers and the Company's mix of owned resources.

Complement to Xcel Energy's overall business plan. A key component of our overall business plan is environmental leadership. We believe that a balanced, clean energy portfolio is in the long-term best interests of our customers. Ownership of renewable resources is one means of demonstrating this commitment for our customers, regulators, and shareholders. We believe we must increase our investment in owned renewable resources to help maintain our financial health, minimize risks through a balanced portfolio, and reduce costs for our customers.

D. Proposed Acquisition Process

In this section, we describe our plan to acquire the replacement generation resources that will be necessary to address the capacity deficit created by our proposal to cease coal operations at Sherco Units 1 and 2.

Consistent with the Commission's January 6, 2016 Order, we will not submit a Sherco conversion plan proposal pursuant to Minn. Stat. § 216B.1692 (Emissions Reduction Statute) any earlier than one month following the Order in this Resource Plan proceeding. We expect that our proposal will take a similar approach to our 2002 Metro Emissions Reduction Project (MERP) petition under the Emissions Reduction Statute.[23] Following an overview and summary of the proposed projects, we will present further details including projected book life, capacity, capital cost, annualized emissions reductions, and proposed project schedule for the proposed thermal and renewable projects. We will address the benefits of our proposal, along with costs, customer impacts, and an analysis of alternatives. Our proposal will also contain a suggested procedural schedule, which we intend to develop in consultation with appropriate state agencies.

[23] Docket No. E002/M-02-633.

Also similar to our approach in 2002, we intend to submit a cost recovery petition within 60 days of our proposal. The Emissions Reduction Statute gives the Commission the authority to implement rate riders to recover the cost of qualifying projects if they appropriately achieve environmental benefits without unreasonable consumer costs. Our filings will provide the factual and analytical support necessary for the Commission to affirm the two key issues in the matter:

- Whether the selections in our Proposal are appropriate, given their environmental benefits and costs, and
- If so, whether our proposed rate mechanism is appropriate and consistent with the terms of the statute.

Following approval of the Sherco conversion plan and associated cost recovery filing we would proceed using a similar approach to our previous MERP conversion efforts. The Company would commence the project under an owner-managed multi-contract approach similar to the previous MERP, CapX2020 and other major projects we have successfully completed in the NSP regions over the past 13 years. We would establish an agreed upon scope, schedule, and budget with the Commission prior to proceeding and would expect to provide regular updates to the Commission on the status of the project through completion.

We would utilize a competitive request for proposal (RFP) process to purchase the major equipment and acquire specialized engineering design and construction resources. An RFP bidding process for the major components of the project ensures we obtain the most competitive pricing. As with the MERP projects, the Company's Engineering and Construction organization would provide overall project management and oversight with support from departments within the Company for environmental, purchasing, safety, and startup & commissioning. Maintaining direct control through project management and oversight of contracts for associated equipment, materials, and service contracts will reduce costs and ensure project quality and timeliness.

We have demonstrated through our successful large scale, multi-year MERP and CapX2020 initiatives, a transparent owner-managed approach that includes regular Commission updates and project costs that stem from competitively-bid contracts for all materials and services delivers on-time and on-budget projects that are in the public interest.

VI. CUSTOMER COST IMPACTS

As we have discussed, our Reference Case is a continuation of the plan we laid out in our 2010 Resource Plan. We now know that it would not achieve compliance with CPP requirements, nor is it consistent with our vision of being a leading provider of cost-effective clean energy. The Updated 2015 Plan that we proposed in January 2015 began to shift the Company to a significantly lower-carbon system; however, with the information currently available it is not certain that the Updated 2015 Plan will be sufficient to achieve CPP compliance under reasonable assumptions of the CO_2 reductions that could be required of the Company under Minnesota's CPP State Plan. Conversely, we are confident that our Current Preferred Plan will achieve CPP compliance, and also provide the reasonably-priced clean energy that our customers are asking for, appropriately balance state energy policy priorities, and optimize the system investments our customers have made to-date with new investments that will maintain reliability.

In this Section, we provide a long-term view of the cost impacts of our Current Preferred Plan. Additionally, at the request of the Commission and the Department at the December 2015 hearing regarding the procedural schedule for this proceeding, we discuss our view and provide illustrative concepts of a potential future market for CO_2 allowances.

A. Long-Term View

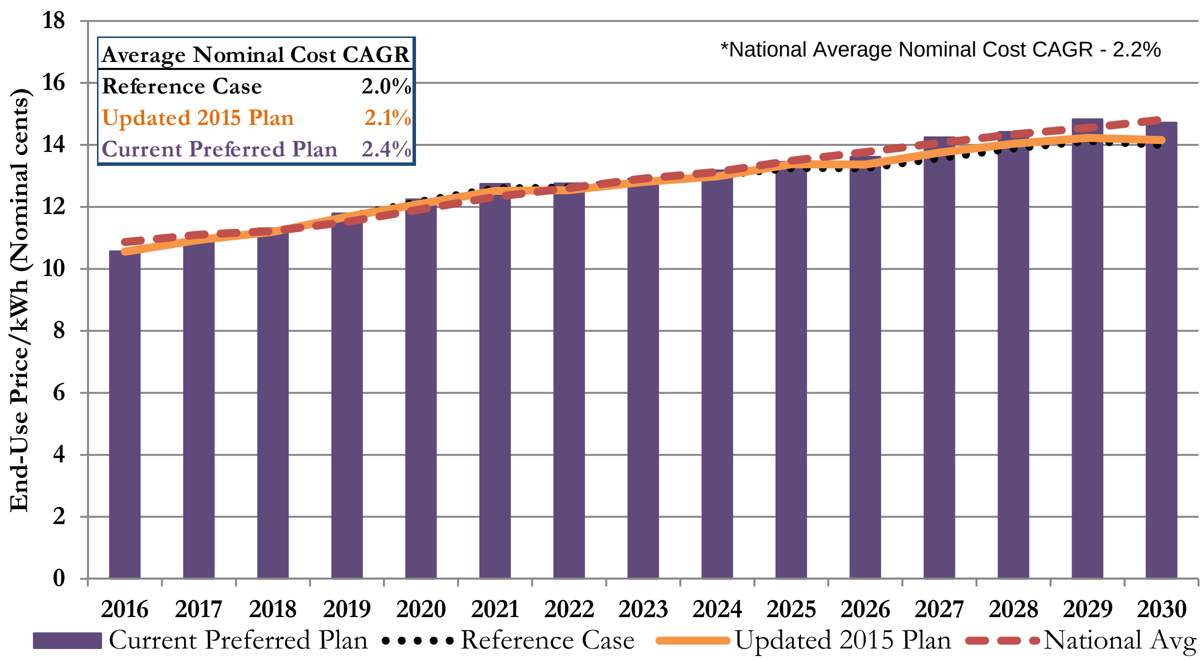
To show the cost impact of our proposal over the course of the planning period, we provide a Compound Average Growth Rate (CAGR) comparison of our Current Preferred Plan, Updated 2015 Plan, and Reference Case. We derived this long-term projection using a shorter-range financial forecast and a special purpose Strategist model, similar to how we projected the long-range cost of our plans in previous filings in this proceeding.[24]

Figure 5 below illustrates the cost differences between the Reference Plan, Updated 2015 Plan and our Current Preferred Plan, compared to the national average nominal cost CAGR. Specifically, the annual average cost delta between our Reference Case and our Current Preferred Plan is less than one-half of one percent. Our Current Preferred Plan also achieves significantly greater CO_2 emissions reductions and is the only one of the three plans that is virtually certain to achieve

[24] We describe this methodology in more detail in Attachment B.

CPP compliance. Moreover, Figure 5 shows that the cost impacts associated with our Current Preferred Plan are roughly consistent with the expected national average increase in electricity prices, and over the long-term closely mimic the rate of inflation.

Figure 5: Current Preferred Plan Average Nominal Cost Comparison (NSP System)



*National energy cost forecast from Energy Information Administration (EIA) Annual Energy Outlook 2015, Table Energy Supply, Disposition, Prices and Emissions. End use prices, all sector average.[25]

While this view of the estimated long-term plan costs is different than presented in previous filings, the relative values are consistent.

B. Potential Customer Benefits of CO_2 Allowance Proceeds

While our Current Preferred Plan is not primarily driven by the CPP, based on what we know now of the state implementation plan, we believe this plan not only achieves, but likely exceeds, the CO_2 emissions reductions that could be required of

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[25] The EIA's Annual Energy Outlook was published in April of 2015, and based on federal, state, and local laws and regulations in effect as of the end of October 2014. Therefore, the potential impacts of pending or proposed legislation, regulations, or standards such as the CPP would not be reflected in these projections.

the Company. As a result, the Current Preferred Plan may generate surplus reductions in the form of CO_2 allowances (if Minnesota's CPP state plan is mass-based) or Emission Rate Credits (if the plan is rate-based). Depending on the design of the state plan, the Company could monetize these surplus reductions on our customers' behalf to mitigate some of the cost impacts of transitioning to a significantly lower-carbon system.

We provide as Attachment H a preliminary analysis of the potential value of CO_2 allowances, in excess of compliance needs, under two hypothetical State Plan scenarios and assuming different CO_2 allowance prices. This analysis is preliminary and speculative because the size of the allowance budget allocated to the Company under the State Plan is not yet known; further, and CO_2 allowance prices in future markets can only be estimated. We describe in Attachment H the rationale we used for the CO_2 allowance prices used below, and provide details of the hypothetical State Plan scenarios labeled "Scenario 1" and "Scenario 2."

If we assume a constant CO_2 allowance price of $21.50 per ton (the midpoint of the Commission's regulatory cost range under Minn. Stat. §216H.06), and assume a "Scenario 1" State Plan that regulates existing units only, contains no allowance set-asides other than the Clean Energy Incentive Program, allocates allowances based on 2010-2012 generation at CPP-regulated units,[26] and does not limit the number of years of allowance allocation to a retired unit, the Current Preferred Plan would generate allowance revenues of about $540 million over 2022-2030 ($258 million in Net Present Value or NPV terms). At the same CO_2 allowance price, if we assume a "Scenario 2" State Plan that contains many allowance set-asides and only allocates allowances for two years after unit retirement, the Current Preferred Plan would generate allowance revenues for our customers of only $75 million over 2022-2030 ($33 million NPV). We have not reflected these speculative potential revenues in any of the cost estimates of our Current Preferred Plan, and provide them here as only a preliminary analysis.

Table 16 below shows the value at three different CO_2 allowance prices that correspond to the Commission's low, midpoint, and high regulatory cost values.

[26] We note that EPA leaves the allowance allocation decision to states, and that discussion of the most appropriate allocation basis (generation or emissions, and whether any allowance set-asides are appropriate) is ongoing as of this filing.

Table 16: Value of Potential CO_2 Allowance Sales Under Two State Plan Scenarios
(millions, undiscounted, over 2022 to 2030)

Allowance Price	State Plan Scenarios – 1 – Customer Value	State Plan Scenarios – 2 – Customer Value	Value Impact to Customers
$9/ton	$226	$31	($194)
$21.50/ton	$540	$75	($465)
$34/ton	$853	$119	($735)

The "Value Impact to Customers" column in this table represents the estimated CO_2 allowance value transferred from the Company's customers to other parties by a State Plan that sets aside significantly more allowances, and discounts the value of retiring coal units by allocating allowances for only a short time post-unit retirement.

Since all allowance values are assumed to accrue to the Company's customers, a "Scenario 1" State Plan would provide around $540 million to help mitigate the cost impacts of transitioning to a lower-carbon energy system. A "Scenario 2" State Plan would provide only $75 million, which is $465 million *less* value to mitigate customer cost impacts, shifting much of the value from our customers to other parties.

We believe that through our involvement in the MPCA's CPP State Plan development process, we can identify opportunities to further offset the cost impact of our proposal and achieve the greatest value for our customers. We also believe there are rate mechanisms, described in more detail below, which can provide predictable cost recovery and help to smooth cost impacts for our customers.

C. Near-Term Customer Rate Impacts

In compliance with the Commission's January 6, 2016 Order and in order to approximate the near-term impacts of plan implementation on customer rates and bills, we provide as Attachment E a detailed rate analysis of our Current Preferred Plan and Updated 2015 Plan. This includes a five-year detailed rate impact analysis with the estimated impacts by class per year.

We note the following factors could impact rates in 2016-2020:

- *Tax credit extension*: With the extension of the Production Tax Credit, the costs of 600 MW wind PPAs beginning in 2020 is reduced significantly from the Base Cost of Energy forecast (Docket No. E002/MR-15-827), which assumed those PPAs would not benefit from PTCs. Wind PPAs are recovered through the fuel clause, which is where the cost reduction would appear for customers.
- *Renewables ownership:* The addition of 200 MW of owned solar and 400 MW of owned wind would result in an increase in base rates or rider rates due to the ownership of 200 MW of solar and 400 MW of wind, presumably recovered in the RES Rider.
- *Ceasing coal operations at Sherco:* The ceasing of coal operations at Sherco Units 1 and 2 would result in increased depreciation expense.

Primarily due to the tax credit extension, both our estimated Updated 2015 Plan and our Current Preferred Plan forecasts show lower fuel costs than our 2016-2020 fuel forecast prepared at the time of the Base Cost of Fuel filing. For example in 2020, the ITC and PTC tax incentives would reduce fuel costs by $99 million in the Current Preferred Plan, while the Updated 2015 Plan results in a $66 million reduction.

VII. NUCLEAR RESOURCE UPDATE

In our October 2 Reply, we expressed our support for utilizing our carbon-free nuclear baseload resources through the existing plant licenses as a means of achieving our goal of a 60 percent reduction of CO_2 emissions from 2005 levels by 2030. At the same time, we explained that our projected capital spend for Prairie Island is outpacing the estimates included in our Changed Circumstance filing in 2012.

We noted specifically that our five-year capital expenditure forecast from 2016 through 2020 has increased by roughly $175 million above what was anticipated in 2012, and that our forecast for the thirteen-year period from 2021 through 2034 would likely need to increase by roughly $600 to $900 million. We also noted that our fixed operating and maintenance (Fixed O&M) costs are lower than previously modeled and that our decreased Fixed O&M forecast largely offsets the increase in our forecasted capital spend.

The Commission expressed understandable concern over our updated capital forecast during hearings in December 2015. We address those concerns here by providing additional information and analysis relating to our support for nuclear and to the costs associated with the continuing operation of Prairie Island. In particular, we provide modeling that takes into account our updated capital and Fixed O&M forecasts and demonstrates that Prairie Island has been, and continues to be, a cost-effective resource for our customers. We also discuss our updated capital expenditure forecasts for the periods from 2015-2020 and 2021-2034 at Prairie Island.

We believe the information provided in this section supports our continued operation of Prairie Island, including the investments we need to make to safely and reliably operate the plant over the next few years. We nevertheless recognize that our opinion is one of several that need to be considered in this process, that stakeholders would like to better understand the implications of our updated forecasts, and that there is some uncertainty at play when considering the costs to operate a two-unit nuclear plant for the remaining 19 years of its licensed life. Utilities, regulators, and stakeholders around the country are grappling with similar issues as they try to balance the increased regulatory pressure and costs associated with nuclear against emerging policies aimed at reducing CO_2 emissions.

We believe that any decision regarding the long-term future of Prairie Island should be made after a deliberate and thoughtful dialogue between the Company, our regulators, and our stakeholders. We further believe this dialogue should be informed by a longer-term, in-depth analysis of the cost-effectiveness of Prairie Island and the alternative paths that could be taken with respect to the plant. In fact, we have begun this work and share a preliminary analysis of one potential alternative later in this section. If the Commission and our stakeholders want to further explore this or other alternatives, we are committed to doing the additional work necessary to advance a fully informed and thoughtful decision-making process. We expect that a full analysis of the operations, economics, and potential alternatives for Prairie Island could be completed in the next 18 months, and we welcome the opportunity to cooperate with our regulators and our stakeholders on such a significant decision.

A. Relation to Supplemental Rate Case Testimony

Following our October 2 Reply, the Commission ordered the Company to file supplemental schedules and testimony in its pending electric rate case that describe and compare projected and actual Life Cycle Management costs (and, to the extent relevant, Extended Power Uprate costs) from 2008 through 2020 by generating unit and year, including the proposed 2016 test year, and the 2017 and 2018 plan years. As part of those descriptions and comparisons, the Company was ordered to include all changes and updates to projected costs from 2008 onward and to include all cites to relevant certificate of need, resource plan, and general rate case dockets. The Commission also ordered the Company to provide as part of those schedules and testimony a comparison of the relevant parts of the proposed 2016 test year, the 2017 plan year, and the 2018 plan year to the proposed five-year capital budget in the Company's pending Resource Plan proceeding.

In compliance with that Order, we are filing supplemental Direct Testimony in our pending rate case docket from Company Witnesses Christopher B. Clark (President), Timothy J. O'Connor (Senior Vice President and Chief Nuclear Officer), Scott L. Weatherby (Vice President for Nuclear Finance and Planning), and John J. Reed (Chief Executive Office at Concentric Energy Advisors). That testimony focuses on the period from 2016 through 2020, the additional $175 million of capital expenditure above what was anticipated in 2012 for that period, and why the capital projects underlying that forecast are necessary during those years and in our customers' best interest.

In this Resource Plan Supplement, by contrast, we address not only the next five years but also the latter portion of Prairie Island's licensed life and the additional $600 to $900 million in capital that we anticipate spending between 2021 and 2034. Because resource planning takes this longer view, we believe it is the appropriate forum to consider whether it is economic and prudent to operate Prairie Island through the end of its licensed life. We therefore welcome an in-depth discussion regarding the future of Prairie Island and, to that end, propose a process to continue that discussion after we have had additional time to study the impacts of continued operations, as well as potential alternatives.

B. Prairie Island's Past and Current Cost-Effectiveness

Our support for utilizing our nuclear baseload through the existing plant licenses is primarily driven by our conclusion that it is beneficial for our customers to do so. We recognize that the principal question in this regard is the plant's cost-effectiveness on a going-forward basis. We believe that it is also helpful, though, to consider the forecasts and modeling we presented in connection with our 2008 certificate of need and 2012 changed circumstance filings. These demonstrate that

Prairie Island has always been cost-effective, even when we account for our updated capital forecast. We therefore briefly address these earlier forecasts and models before turning to our prospective analysis.

1. *Past Forecasts & Modeling*

At the time we filed our certificate of need in 2008, we provided an estimate of capital costs running to the end of Prairie Island's licensed life in 2034 in an effort to measure the plant's cost-effectiveness compared to either a super critical pulverized coal unit or a natural gas CC unit. We provided this information in response to Minn. Stat. §216B.243, subd. 3b, which states that "[a]ny certificate of need for additional storage of spent nuclear fuel for a facility seeking a license extension shall address the impacts of continued operations over the period for which approval is sought."

Because we sought authorization for enough casks to operate Prairie Island until 2034, we provided our best judgment with respect to the "impacts of continued operations" until that time. Looking to historical capital expenditures, we estimated that our routine capital investment would average approximately $20 million annually ($10 million per unit) and that we would spend an additional $600 million on large capital investments from 2008 through 2034. Using these numbers, we concluded that continued operation of Prairie Island was cost-effective by a margin of $2,194 million in PVRR. We then updated our capital forecast for Prairie Island in our 2012 changed circumstance filing and included additional capital expenditures in that model.

For a number of reasons that are discussed below, our 2008 capital forecast has proven to be lower than the actual costs incurred to-date. Likewise, our 2012 forecast appears to be lower with respect to our updated forecast for the out-years of Prairie Island's licensed life. As an initial matter, however, it is important to contrast our 2008 capital expenditure forecast from one more typically associated with a certificate of need filing and from the Monticello prudence review. In the Monticello docket, for instance, we had already spent more than forecasted in our LCM/EPU certificate of need filing, and we sought recovery of those capital expenditures after the construction project was completed.

There is no construction project at issue here. Our 2008 filing related to dry-storage casks and provided a forecast related to the "impacts of continued operation" for a two-unit nuclear plant over a twenty-six-year period. It was the first time we provided such an estimate and the first time we forecasted capital expenditures for the out-years of an extended-life nuclear plant. And unlike Monticello, we are updating the Commission with respect to our increased capital forecast having not yet exceeded our 2008 forecast and not expecting that we will exceed the total cost (capital plus Fixed O&M) we forecasted in our 2008 filing.

That said, one reason for the higher-than-anticipated capital expenditures is that our Nuclear Regulatory Commission (NRC) mandated compliance expenses have increased substantially in recent years, both as a result of new NRC requirements following the Fukushima Daiichi incident, and as a result of increased oversight and regulation by the NRC generally. Additionally, our estimate of spending $10 million per unit annually for routine capital investment has proven to be insufficient, despite that having been a reasonable estimate in light of historical spending up to and including 2008. Our experience with routine capital investment over this period mirrors that of other utilities operating similar nuclear plants.

Although our capital expenditure forecasts have increased since 2008, our Fixed O&M forecasts have decreased in nearly equal measure. In 2008, we provided a conservative estimate of Fixed O&M costs in connection with our certificate of need filing, which was based on our historic spending up to that point. Since that time, however, we have observed significantly lower-than-forecasted Fixed O&M spend, which caused us to revisit that forecast in conjunction with our resource plan and to reconsider what future Fixed O&M growth will be over the next 19 years of Prairie Island's licensed life. Based on historical spending from 2008 to present, we now forecast spending more than $1 billion less in Fixed O&M at Prairie Island from 2015 through 2034. And if we look at total spend (capital plus Fixed O&M) in connection with Prairie Island, our current forecast results in PVRR that is $981 million less than our 2008 certificate of need forecast and $91 million less than our 2012 changed circumstance forecast. Thus, our revised Fixed O&M forecast not only offsets our revised capital expenditure forecast, it results in a projected total project cost that is substantially less than we anticipated in both 2008 and 2012.

Had we used our current capital expenditure projections in our 2008 model, it would have shown that Prairie Island remained a valuable, cost-effective resource by a margin of approximately $2.04 billion in PVRR. Likewise with our 2012 changed circumstance proceeding, Prairie Island would have remained a cost-effective resource by a margin of approximately $305 million in PVRR, using the model from that filing. Further, because our 2012 modeling assigned no cost to CO_2, the PVSC of Prairie Island under that analysis would have been substantially higher. As a result, our updated capital and Fixed O&M forecasts would not have changed our conclusions with respect to the continued operation of Prairie Island in either the 2008 certificate of need or 2012 changed circumstance proceedings.

2. Prairie Island's Current and Future Cost-Effectiveness

We now turn to the present-day cost-effectiveness of Prairie Island. For this analysis, we used our current Strategist modeling from this docket and considered a base case with the current forecast for ongoing capital and O&M expenditures compared with a scenario where Prairie Island is retired immediately. In a number of ways, this analysis is highly conservative. First, we have assumed that all of the capital and O&M expenditures for Prairie Island for 2016 through end of life can be avoided entirely, despite the fact that nuclear units continue to experience significant Fixed O&M costs during the various stages of decommissioning and despite the fact that the NRC would likely require a number of Fukushima-related and other mandated projects to be completed even following a shutdown.

Second we have not included any adjustments for accelerated depreciation of the existing asset, or changes to decommissioning costs or fund accruals, both of which we address in greater detail later in this section. Third, we have not included the costs of addressing transmission system impacts that would be caused by shutting down a significant baseload unit, as we have not yet studied these transmission effects in detail. Finally, we have assumed that replacement capacity could be installed "overnight" in 2016, and Strategist was allowed to optimize both the immediate replacements and balance of the expansion plan through the end of the study period. For a number of reasons discussed later in this section, it is simply not possible to immediately retire Prairie Island, or any nuclear plant. Major system transitions of this sort take years to study, plan, and execute, and industry experience teaches that unplanned shutdowns can be enormously expensive by comparison.

The results of this very conservative analysis are shown below in Table 17:

Table 17: Prairie Island Compared to a Natural Gas Combustion Turbine

Resource	PVSC	PVRR
Prairie Island	$52,519	$46,618
Combustion Turbine	$53,750	$46,824
Difference	$1,231	$206

Even our most conservative analysis, then, shows that "overnight" replacement of Prairie Island would result in $1.231 million of additional PVSC. We also evaluated the PVSC and PVRR associated with the capital expenditure and Fixed O&M forecasts over the near-term period from 2016-2020. Continued operations of Prairie Island through this period results in a PVSC savings of $456 million and PVRR savings of $177 million compared to the overnight replacement scenario.

To be sure, the PVRR of running Prairie Island results in a closer call. In this way, the social cost of carbon plays a role in driving our support for continuing to operate Prairie Island through its licensed life, just as it does our decision to cease coal operations at Sherco Units 1 and 2 in the 2020s. We further recognize that changes to certain modeling assumptions, such as lower gas forecasts, could cause the PVRR numbers to suggest – under this limited analysis – that retiring Prairie Island in the near term might result in lower PVRR. It is important to keep in mind, however, this is a theoretical analysis intended to provide a preliminary look at Prairie Island's baseline economics, that it cannot substitute for an in-depth study that accounts for actual retirement and replacement costs, and that there are significant benefits to our nuclear fleet that are not captured by this, or any, Strategist model.

3. Operational & Policy Concerns

We believe that continued operation of our nuclear fleet is also the best path forward from both a policy and reliability perspective. Nuclear comprises more than half of our carbon-free generation and – at the same time – provides our system with a baseload energy resource that ensures critical system reliability. In this way, it is a keystone of the carbon-reduction goals set forth in our Current Updated 2015 Plan. Renewable technology such as wind and solar cannot fulfil this role at a reasonable cost today. As a result, any near-term replacement of our nuclear plants would involve the addition of more natural gas to our fleet, meaning the closure of Prairie Island would have twin effects of heightening our customers' exposure to gas price volatility and significantly increasing our CO_2 emissions. We do not believe this is in the best interest of our Company, our customers, or the states we serve.

We recognize, however, that battery technology is evolving, that renewable costs have decreased in recent years, and that reliable renewable baseload energy may be on the horizon. With that in mind, we see our nuclear units as critical to meeting our carbon-reduction and reliability goals in the near-term (including our compliance with the CPP) and also as a bridge that can facilitate a transition to even greater renewable generation in the longer-term as battery technology improves and costs decline. At the same time, our nuclear fleet is an integral part of our diversified generation portfolio and provides an important hedge to gas price volatility.

Finally, combining the cessation of coal operations of Sherco Units 1 and 2 along with the shutdown of Prairie Island all in the 2020s would present enormous challenges and costs with respect to replacement generation, transmission, and system reliability. The continued operation of our nuclear fleet as a bridge resource will allow for a careful and focused transition away from coal generation in the 2020s before addressing the future of other baseload units.

C. Forecasted Investments

1. Forecasted Investments from 2016-2020

In total, we anticipate investing approximately $490 million in capital at Prairie Island from 2016 through 2020. This is roughly $175 million more than we forecasted as part of our 2012 changed circumstance filing. There are a few key drivers of our increased capital spend during this period. First, $84 million of this increase is due to regulatory mandates from the NRC. As described in our previous two rate cases, these NRC Fukushima, fire safety, physical security, and cyber security requirements did not exist or were not fully known between 2008 and 2012.

More than half of the remaining $90 million is a result of our decision to defer certain projects from the rough timeframes anticipated in our 2008 and 2012 forecasts. In fact, we invested $51 million less from 2008-2015 than we forecasted in our 2012 changed circumstance filing. The remaining capital expenditures during this period simply reflect our inability to perfectly forecast costs in a certificate of need proceeding broadly focused on the remaining life of a plant, as well as increasing costs of nuclear construction and life-cycle maintenance across the industry.

As detailed in Mr. O'Connor's Supplemental Direct Testimony in our pending rate case, the major capital investments forecasted for 2016-2018 include reactor coolant pump replacements, heater drain tank pump speed controls, motor rewinds/replacements, cooling tower replacements, and the main electrical generator replacement for Prairie Island Unit 1. In his Supplemental Direct Testimony, Mr. O'Connor describes each of these projects and explains why they are necessary to safely and reliably operate the plant, even if Prairie Island were not to operate until the end of its licensed life.
Department of Commerce Information Request No. 74 in our currently pending electric rate case requested that we provide an estimate of the necessary retirement dates for Prairie Island Units 1 and 2 under the assumption that substantial (over $40 million per year for the site) new capital expenditures would not occur starting in 2016. Our forecasted capital expenditures for the combination of mandated compliance projects and dry fuel storage alone total $38.9 million in 2016, $36.1 million in 2017, and 34.8 million in 2018. These expenditures are necessary to operate the plant within the NRC's mandates and would leave very little additional capital within the $40 million annual budget to complete basic and necessary LCM projects during these years. Given this, and the fact that any single outage could require more than the remaining amount of budgeted capital to resume operations, it is impossible to predict how long Prairie Island could operate under these budget constraints.

2. *Forecasted Investments from 2021-2034*

In our October 2 Reply, we explained that our forecast for the fifteen-year period of 2021 through 2034 would likely need to increase by roughly $600 to $900 million. We revised our forecast following a project-by-project analysis of anticipated capital investments at Prairie Island from 2015 through 2034, and we believe that it is responsible to anticipate and plan for all of the projects underlying our forecast. In other words, our updated forecast reflects our best judgment regarding these costs, which we presented to the Commission in October so that it can undertake a thorough assessment of our Current Preferred Plan. That said, it is not possible to accurately predict not only which projects will be necessary over a 19-year period, but also what those projects will cost. It is likewise not possible to predict what regulatory mandates will arise in the future, and what compliance with those unknown mandates might cost. Given this uncertainty, we understand certain stakeholders' desire to explore and maintain future optionality with respect to Prairie Island, and we address those concerns below.

D. Future Optionality at Prairie Island

As already discussed, we believe that Prairie Island continues to benefit our customers by producing cost-effective, carbon-free baseload energy that is a keystone to our carbon-reduction goals and a bridge to additional renewable development in the future. We recognize, however, that it is impossible to perfectly forecast costs for the remaining 19 years of Prairie Island's licensed life and that certain of our stakeholders may want to explore alternatives based on that uncertainty. To that end, we have begun to identify and analyze one potential alternative for the plant around the 2025 timeframe. We recognize that other alternatives exist. We present this preliminary analysis as an example of the considerations and analyses that would go into an in-depth discussion of alternatives, and we welcome further dialogue regarding this or other alternatives.

Before proceeding with any in-depth discussion of alternatives for Prairie Island, we would need to conduct a detailed study of its effect on our transmission system, as we did in connection with our proposal to cease coal operations of Sherco Units 1 and 2. This would include a MISO Y2 Study, our own reliability study, and a black start study – just as we are providing in connection with our Current Preferred Plan. And as we did for Sherco, we would need to conduct impact studies relating to our employees at Prairie Island and the community around Red Wing, Minnesota. Finally, the technical studies completed in connection with our Sherco proposal may need to be reconsidered, as the study models assumed that Prairie Island would continue to operate.

If the Commission and our stakeholders wish to have a longer-term discussion concerning the future of Prairie Island, we are committed to completing this work, which we expect would take approximately 18 months. At that point, we would welcome input from stakeholders and the Commission, and we believe that a decision could be made with respect to Prairie Island's future sometime in 2018. If a decision was reached to pursue an early retirement for Prairie Island, we would need an additional seven years to plan for the shutdown and decommissioning, including the construction of replacement generation and any transmission projects that would be needed to maintain system stability. This planning period is critical, as recent industry experience teaches that hastily planned (or unplanned) shutdowns can be extraordinarily expensive as compared to shutdowns that are preceded by several years of planning. Company witness Mr. John Reed discusses the importance of advanced planning for nuclear retirements in his Supplemental Direct

Testimony, which is being filed in our pending rate case contemporaneously with this Supplement. The seven-year timeline is also similar to the one we have proposed in connection with Sherco Units 1 and 2, and would result in a shutdown of Prairie Island around 2025.

To be clear, we do not currently foresee an economically prudent time to retire Prairie Island prior to the end of its licensed life. That said, we believe that an off-ramp in the 2025 time period would result in certain financial benefits as compared to an earlier retirement. Net plant balance is set to peak in 2018 at $1.127 billion. A retirement in that time period would result in substantially increased stranded costs, in addition to the costs otherwise associated with early retirement. During the early 2020s, however, net plant balance begins to decrease and, by 2025, would be within approximately $125 million of today's value of $917 million. That additional $125 million of net plant would itself be more than offset by the additional 10 years of investment growth in our decommissioning fund, which has a current market value of approximately $725 million and earns a return of approximately 5-6 percent (or between $36 million and $43 million) annually.

Additionally, if a decision were made around 2018 to retire Prairie Island in the mid-2020s, we could reduce our capital expenditures during the intervening years, as we normally anticipate lower capital spend in the years leading up to a plant's planned retirement. While we have not yet studied this capital adjustment in-depth, we estimate that our capital expenditures could be reduced such that net plant in 2025 would be significantly less than today's value of $917 million—provided we have several years to plan for the retirement. The strategy of reduced capital expenditures in the 2020s would come with a risk of a modest capacity derate at Prairie Island beginning around 2022 due to decreased capital investment, but we see this as a reasonable risk if the Commission and our stakeholders wish to pursue an early retirement.

The growth of our decommissioning fund is a significant factor that should be taken into account when considering alternatives to operating Prairie Island through its licensed life. Table 18 below compares the approximate amounts of customer contributions versus investment growth that would be needed to fully fund decommissioning at Prairie Island for three examples of potential retirement years:

Table 18: Decommissioning Funding Broken Into Customer Contributions and Investment Growth

	2020	2025	2034
Customer Contributions	$518 million (58.67%)	$374.5 million (40.87%)	$10 million (0.64%)
Investment Growth	$319 million (41.33%)	$541.8 million (59.13%)	$1.552 billion (99.36%)

In short, the longer our decommissioning fund enjoys market growth, the less our customers will be required to pay to fund decommissioning at Prairie Island. This, in combination with the decreasing trend in forecasted net plant balance over the early 2020s, suggests that a retirement significantly before 2025 would involve substantially higher decommissioning and stranded costs.

As already discussed, we have conducted some preliminary modeling around the replacement of Prairie Island with a natural gas CT plant in 2025. Doing so would result in an increase of $929,614 million in PVSC and $601,257 million in PVRR. This analysis incorporates our current best judgment as to the costs of building replacement generation, the depreciation associated with Prairie Island, and the acceleration of decommissioning costs at Prairie Island – including most significantly, the elimination more than a dozen years of investment growth. Our PVSC model also incorporates the regulatory cost of emitting additional CO_2, which we have valued at $21.50 per metric ton beginning in 2019.

It is important to note that we have not conducted an in-depth replacement study with respect to Prairie Island. That analysis would include many of the technical studies that have already been completed for Sherco and the inclusion of specific costs related to transmission remediation and decommissioning that we are not currently in a position to forecast. We view this high-level analysis as buttressing our earlier cost-effectiveness modeling and as supporting the continued operation of the plant, at the very least through the next few years as we further study alternative scenarios.

E. Next Steps

There is much work to be done if the Commission wishes to pursue an in-depth discussion concerning the future of Prairie Island. As already discussed, we would need to complete several technical and impact studies, as we did in connection with our Sherco proposal. We may also need to reevaluate the technical studies completed in connection with our Sherco proposal, in which we assumed the continued operation of Prairie Island on our system. We believe this analysis is critical to making a fully informed judgment on this significant planning issue, and we are committed to doing this work over the next 18 months if the Commission wishes to further explore alternatives to operating Prairie Island through its current licensed life.

Prairie Island remains cost-effective, and our near-term investments are necessary to continue operating the plant today. Additionally, the bulk or our anticipated capital investments will occur in the out-years of Prairie Island's licensed life. As a result, there is time to engage in a thoughtful process, and we welcome this opportunity to dialogue with our stakeholders in hopes of charting a path that is best for our customers and the states we serve.

VIII. ACTION PLANS

A. Five Year Action Plan (2016-2020)

Our Five Year Action Plan discusses near-term actions by resource type, which is primarily focused on wind and solar resource additions.

Wind. The remaining 400 MW of the 750 MW of wind generation resulting from our 2013 RFP is expected to achieve commercial operation in 2016, which includes the 200 MW Courtenay project for which the Company took over ownership in 2015. In light of the recent PTC extension, we plan to develop and finalize our acquisition plan later in 2016 for securing an additional 800 MW of PTC wind by 2019. Currently, in order to obtain the full benefit of the PTC, wind projects must secure a "safe harbor" designation by the end of 2016 by incurring at least 5 percent of the project costs. Construction must be completed by the end of 2018. The PTC is reduced in subsequent years for projects meeting these milestones. We believe it is in the best interest of our customers to obtain the full PTC value; it may therefore be necessary to bring a wind acquisition proposal before the Commission in the latter half of this year for approval on an accelerated schedule.

Solar. The 187 MW of utility-scale solar generation resulting from our 2014 RFP, and the 100 MW Aurora Solar project resulting from the 2012 CAP proceeding are expected to achieve commercial operation in 2016. In light of the recent federal 30 percent ITC extension, we plan to develop and finalize an acquisition plan later in

2016 to secure an additional 400 MW of 30 percent-ITC eligible utility-scale solar resources by 2020. There are similar safe-harbor provisions for the ITC as there are for the PTC for wind, however we have a longer runway. We note that we may adjust the amount of utility-scale solar resources we would seek based on the amount of small solar resources added to our system. The amounts indicated in our Expansion Plan (Table 2) are based on the updated small solar forecast we discuss in Attachment B to this Supplement.

Hydro. We will continue to evaluate the potential and value of hydro resource options including the potential for hydro resources from Manitoba Hydro beyond the current contracts that expire in the mid-2020s.

Natural Gas/Oil Peaking. We will continue to analyze older CTs on the NSP System to avoid impact of increased forced outages due to a major equipment failure and associated unexpected loss of capacity.

Coal. After this Resource Plan proceeding concludes, we will develop and submit a proposal that seeks to implement our proposal to cease operation of Sherco Unit 2 in 2023 and Sherco Unit 1 in 2026, and construct replacement generation resources needed as a result of these changes

Nuclear. Continue to utilize our cost-effective nuclear resources to achieve carbon-reduction goals and maintain reliability. Continue to dialogue with our regulators and stakeholders regarding the future of Prairie Island. If the Commission wishes to further explore alternatives to operating Prairie Island through its current license, complete the economic, technical, socioeconomic studies necessary to advance that discussion.

North Dakota. If the North Dakota commission takes action to approve our proposed Negotiated Agreement, we expect to begin working with Commission staff in 2016 toward developing a Resource Treatment Framework that would likely be filed with the Commission sometime in 2017. We believe additional discussions with all of our state Commissions will be necessary during the five-year action planning period to address divergent energy policies and changes in cost allocations that may result.

B. Long Term Plan Action Plan (2021-2030)

Proposed actions during the 2021-2030 period:

- Complete preparations for ceasing coal operation of Sherco Unit 2 in 2023 and Sherco 1 in 2026.
- Complete preparations to add our proposed natural gas CC at the Sherco site in 2026, achieving commercial operation prior to ceasing coal operations at Sherco Unit 1.
- Complete the natural gas infrastructure to supply the proposed Sherco CC.
- Complete preparations to add the proposed natural gas CT in North Dakota by the end of 2025.
- Effectively manage planned retirement of older CTs.
- Evaluate and determine the merits of extending or renewing expiring wind, thermal and hydro generation PPAs.
- Actively work to identify and act on opportunities to implement cost-effective and reliable distributed generation, electric storage units and other commercial ready technologies that are responsive to customer needs and comply with applicable requirements.

Minn. Stat. § 216H.02, subd. 1 requires that we provide an update on our progress toward the goal of achieving 80 percent CO_2 reduction by 2050. We expect our Current Preferred Plan to achieve at least at 35 percent CO_2 reduction from 2005 levels by 2020 and nearly 60 percent by 2030 – positioning us well to help Minnesota achieve its objective to reduce CO_2 by 80 percent by 2050. We note that our Monticello and Prairie Island nuclear facilities are essential to achieving the reductions we propose in our Current Preferred Plan and the 2030 CPP objectives. We discuss our nuclear units and their role on the NSP System more in depth in Section VII of this Supplement.

Our Current Proposed Plan achieves a 60 percent reduction in CO_2 emissions by 2030 milestone by adding 3,200 MW of new renewables and ceasing coal operations at Sherco Units 1 and 2 during the 2016-2030 planning period. Renewable additions begin with an 800 MW addition of competitively-priced PTC wind additions by 2020 and an additional 1,000 MW of non-PTC wind by 2030. Solar additions include adding 400 MW of competitively priced utility-scale ITC solar by 2020 and additional 1,000 MW by 2030. This adds to the 287 MW of utility-scale solar going into service in 2016. We note that we now expect small-scale solar resources to potentially reach 1,100 MW by 2030, which we discuss in Attachment B.

IX. PUBLIC INTEREST ANALYSIS

Based on our detailed analysis, we conclude that the Current Preferred Plan is in the public interest. It puts the Company on a path to transform its fleet in a planful, coordinated manner that ensures we will meet our obligations under the CPP and the most stringent of our state renewable energy and carbon reduction requirements, while effectively managing costs and preserving flexibility on behalf of our customers. It provides our customers, employees, and our communities with certainty, while also maintaining a balanced diversity of energy sources, and investment opportunities that benefit our state economies and communities. Finally, it promotes an orderly, gradual transition of our generation fleet and thus avoids a scenario where the Company may have to retire and replace five baseload generating facilities in the early 2030s.

Minnesota Commission rules (Minn. R. 7843.0500, subp. 3) identify the factors that the Commission is to consider when determining if the Resource Plan selected is in the public interest. More specifically, these rules require that resource options and resource plans are to be evaluated on their ability to:

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

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

A. Reliability

Our Current Preferred Plan is designed to maintain the adequacy and reliability of the NSP System and will allow the Company to continue to provide safe and reliable service to its customers. Our plan promotes an orderly, gradual transition of our generation fleet and thus avoids a scenario where the Company may have to retire and replace five baseload generating facilities in the early 2030s.

B. Impact to Customers' Bills

We developed our Current Preferred Plan with impacts to customers in mind. Given the regulatory and other constraints of the planning landscape, we sought to achieve additional flexibility and achievement of policy goals at a reasonable additional cost. For an incremental increase of less than one-half of one percent over the planning period compared to business as usual, we achieve nearly 60 percent reduction in our CO_2 emissions from 2005 levels, near certain CPP compliance, and assured reliability for our customers.

C. Socioeconomic and Environmental Effects

Our Current Preferred Plan will benefit our states by advancing both federal and state energy policies and by being nearly certain to comply with the final Clean Power Plan rules. It will also benefit our communities by allowing adequate time to transition our workforce and promoting economic development during this fleet transition. For these reasons, we believe that our Current Preferred Plan charts the right path forward for our Company and stakeholders.

D. Flexibility to Respond to Change

Our Current Preferred Plan was developed to position the Company well in the current planning landscape. Obtaining strategic flexibility is a key component of doing so. This flexibility enhances our ability to respond to changes in the financial, social, and technological factors affecting our operations during the planning period – and preserves optionality for us to respond to these factors beyond the planning period.

E. Limiting Risks

Much like the flexibility to respond to change, the strategic flexibility inherent in our Current Preferred Plan limits the risk of adverse effects on the Company and our customers from financial, social, and technological factors beyond our control. Key to limiting such risk is our planful and coordinated fleet transition that ensures we will meet our obligations under the CPP and the most stringent of our state renewable energy objectives and carbon reduction requirements.

We envision an energy future that includes a dramatic reduction in carbon emissions so that, by 2030, our energy mix will be 63 percent carbon-free. Taking action to transition our fleet now mitigates the costs and risks of retiring a significant proportion of our baseload generation in the same time period along with environmental regulatory risks to the economic viability of our older coal units, and provides certainty to our customers and stakeholders throughout the planning period. Our proposal to achieve this vision will benefit our customers, communities, and the states we serve. Our customers will benefit from our cost-effective transition to the cleaner energy future they want, while preserving the reliable and safe service they expect, which we can accomplish for just a fraction of a percent more in incremental cost over earlier plans. Our Current Preferred Plan represents the best option to meet customers' needs in light of the planning landscape and presents the best path forward for the Company, our customers, and the energy future of the Upper Midwest area. For these reasons, we believe our Current Preferred Plan is in the public interest, and we respectfully request the Commission's approval for planning purposes.