July 26, 2019 **PUBLIC DOCUMENT**

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

RE: **Public Supplemental Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. IP6949, E002/PA-18-702

Dear Mr. Wolf:

Attached are the **PUBLIC** supplemental comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

Petition for Approval of the Acquisition of the Mankato Energy Center.

The Petition was filed on November 27, 2018 by:

Aakash H. Chandarana
Regional Vice President, Rates and Regulatory Affairs
Northern States Power Company
414 Nicollet Mall
Minneapolis, MN 55401

Overall, the Department recommends that the Minnesota Public Utilities Commission (Commission) **reject the petition**. However, the Department recommends conditions, should the Commission determine that the proposal is in the public interest. The attached comments do not address the site permit transfer request. The Department's team of Nancy Campbell and Steve Rakow is available to answer any questions the Commission may have.

Sincerely,

/s/ STEVE RAKOW
Analyst Coordinator

/s/ NANCY CAMPBELL
Analyst Coordinator

SR/NC/ar
Attachment

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Analysts Assigned: Nancy Campbell, Steve Rakow

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Before the Minnesota Public Utilities Commission

PUBLIC Supplemental Comments of the Minnesota Department of Commerce, Division of Energy Resources

Docket No. IP6949, E002/PA-18-702

I. INTRODUCTION

For ease of reference, the Department recaps the procedural history identified in our March 5, 2019 comments, updated as appropriate.

On November 27, 2018, Northern States Power Company, doing business as Xcel Energy (Xcel, NSPM, or the Company) filed the Company's *Petition for Approval of the Acquisition of the Mankato Energy Center* (Petition) pursuant to Minnesota Statutes § 216B.50. Since 2006, Xcel has had a 20-year purchased power agreement (PPA) to purchase power from the first Mankato Energy Center (MEC I), a 375-MW one-on-one natural gas combined cycle facility.

The Minnesota Public Utilities Commission (Commission) approved Xcel's second 20-year PPA, this time for power from the Mankato Energy Center expansion project (MEC II). The Commission approved this PPA in 2014, in a resource acquisition process stemming from the Company's 2010 integrated resource plan (IRP).[1] MEC II expands the existing MEC I facility by 345 MW via the addition of a new combustion turbine and heat recovery steam generator resulting in a two-on-one natural gas combined cycle facility. Total capacity under these two PPAs is 720 MW.

In October 2016 Calpine Corporation, the original owner and developer of the MEC facilities, sold the MEC I facility and MEC II expansion rights to Southern Power Company[2] (Southern).

On June 4, 2019, MEC II reached commercial operation, thus beginning the timing for the second 20-year PPA.

The Company requests that the Commission:

- determine that the proposal to acquire the existing MEC I facility is prudent and in the public interest under Minnesota Statutes § 216B.50;
- approve a fuel clause adjustment (FCA) variance under Minnesota Rules 7829.3200 allowing the Company to recover the difference between the 2019 revenue requirement resulting from the transaction and the revenues already in base rates for the capacity portions of the current MEC I and MEC II PPAs;

[1] Resource plan was Docket No. E002/RP-10-825; resource acquisition was Docket No. E002/CN-12-1240.

[2] Southern Power Company is a wholly-owned affiliate Southern Company.

- approve the transfer of the site permits for MEC I and MEC II under Minnesota Rule 7850.5000;
- issue a notice setting a schedule for comments and reply comments from interested parties on the Petition;
- establish a procedural schedule such that the Commission may issue a written order as close as practicable to June 2019 so Xcel may proceed with the transaction as contemplated by the agreement with Southern; and
- vary its rules, consistent with past practice, with respect to certain filing requirements referenced in Minnesota Rules 7825.1800.

On December 20, 2018 the Commission issued its *Notice of Comment Period* indicating that the following topics are open for comment:

1. Is the purchase proposal prudent and in the public interest?
2. What are all the assumptions/inputs used to develop the cost/benefit analysis? Are those assumptions/inputs consistent with Xcel's stated goals to be carbon-free by 2050? Are those assumptions/inputs reasonable?
3. Should Xcel be allowed to recover the difference between the 2019 revenue requirement resulting from the transaction and the revenues already in base rates for the capacity portions of the MEC I and MEC II PPAs?
4. If the transaction is approved, how should cost recovery be effected?
5. If the transaction is approved, will it require any rule variances and, if so, which rules should be varied?
6. If the transaction is approved, how will it impact the 2019 Capital True-Up filing?
7. If the transaction is approved, how will it impact Xcel's capital structure?
8. If the transaction is approved, how do the MEC I and MEC II useful lives fit with Xcel's stated goal to be carbon-free by 2050?
9. If Xcel becomes carbon-free by 2050, should ratepayers be liable for any resulting MEC I and MEC II related stranded costs?
10. Should approval be subject to any conditions and, if so, what should those conditions be?
11. What action should the Commission take regarding the request to transfer the site permit in this docket?
12. Are there other issues or concerns related to this matter?

Between February 7, 2019 and March 5, 2019 comments were filed by the following parties:

- Southern Power Company (Southern), on behalf of Mankato Energy Center, LLC and Mankato Energy Center II, LLC;
- Greater Mankato Growth, Inc.;
- IBEW Local Union 949;

- Laborers District Council of Minnesota and North Dakota (LIUNA);
- The Institute for Local Self-Reliance and Cooperative Energy Futures;
- Various members of the public:
  - Jacob Herbers;
  - Mallory Mitchell;
  - Debbie Meister; and
  - Anthony Varriano;
- the city of Mankato;
- the city of Minneapolis;
- Sierra Club;
- Office of the Attorney General—Residential Utilities and Antitrust Division (OAG);
- Xcel Large Industrials; and
- Minnesota Department of Commerce, Division of Energy Resources (Department).

On March 28, 2019 over 800 members of the public filed comment letters opposing Xcel's proposed purchase, citing concerns about costs and the environment.

On March 29, 2019 Xcel and Southern filed reply comments.

Also on March 29, 2019 the Citizens Utility Board of Minnesota (CUB) requested time to respond to Xcel's reply comments and indicated that CUB would submit its comments by April 5, 2019.

On April 3, 2019 the Commission issued a *Notice of Supplemental Comments* (Notice), indicating that supplemental comments were due April 30, 2019. The Notice indicated that the issue at hand is "Should the Commission approve the purchase of the Mankato Energy Center and approve transfer of its site permit?"

On April 29, 2019, at the request of the Department, the Commission issued a notice indicating that supplemental comments were due May 21, 2019.

On May 17, 2019, at the request of Xcel, the Commission issued a notice indicating that supplemental comments were due June 11, 2019.

On May 20, 2019 Xcel filed a *Settlement Agreement* regarding the Petition and the Company's upcoming 2019 IRP filing. Signatories to the *Settlement Agreement* include:

- the Company;
- LIUNA;
- Clean Grid Alliance;

- Center for Energy and Environment;
- Minnesota Center for Environmental Advocacy;
- Union of Concerned Scientists;
- Fresh Energy; and
- Sierra Club.

On May 20, 2019, Clean Grid Alliance, Fresh Energy, Minnesota Center for Environmental Advocacy, the Union of Concerned Scientists, and the Center for Energy and Environment filed supplemental comments in support of the *Settlement Agreement*. Also, Sierra Club filed a request to withdraw from the record the comments Sierra Club filed on March 5, 2019.

On May 21, 2019, Commission Staff sent several information requests to Xcel.

On May 22, 2019, the Citizens Utility Board of Minnesota and Carol Overland filed objections to the request by Sierra Club to withdraw from the record the March 5, 2019 comments.

On June 6, 2019, the OAG requested a two-week extension to file comments, to June 25, 2019, noting the need to assess Xcel's responses to Commission Staff. In addition, Commission Staff sent more information requests.

On June 12, 2019 the city of Minneapolis filed supplemental comments concluding that the MEC acquisition is not prudent. In addition, Commission Staff sent more information requests.

On June 19, 2019, Xcel filed a request for a two-week extension to file supplemental comments, to July 9, which Commission Staff granted on June 20.

On June 24, 2019, the Institute for Local Self-Reliance and Cooperative Energy Futures filed comments agreeing that Sierra Club's request to withdraw from the record the March 5, 2019 comments should not be granted, along with identifying concerns with Xcel's proposal, concluding that the proposal is imprudent, and recommending that, if the Commission approves the proposal, sufficient consumer protections should be in place.

Also on June 24, 2019, Advanced Energy Management Alliance filed comments noting concerns that the decision was taking place outside of an integrated resource plan and did not consider demand response and other resources as alternatives to the proposal.

On July 3, 2019, Xcel received another extension to filing supplemental comments, to July 26, 2019.

Below are the Department's supplemental comments regarding the issues raised by Xcel's reply comments, additional data provided by the Company, and the Notice.

II. DEPARTMENT ANALYSIS

A. APPLICABLE STATUTES

As discussed below, these are first comments in which the Department determined that Xcel provided resource planning analysis that was sufficiently valid to allow for analysis of the reasonableness of the models. Thus, the Department notes that statutes in addition to those reference in the March 9, 2019 comments must be considered. Specifically, regarding renewable resources, in Docket No. E015/AI-17-568 the Commission's September 19, 2017 *Order Referring Gas Plant for Contested Case Proceedings, and Notice and Order for Hearings* at point five stated that "The renewable resource requirements set forth in Minn. Stat. § 216B.2422, and Minn. Stat. § 216B.243, subd. 3a will apply to consideration of Minnesota Power's proposed gas plant." In addition, the Commission's January 24, 2019 *Order Approving Affiliated-interest Agreements with Conditions* (NTEC Order) stated that "Because the NTEC [Nemadji Trail Energy Center] purchase involves resource-planning and resource-acquisition considerations, the Commission's determination of whether the affiliated-interest agreements are "reasonable and consistent with the public interest" is guided by relevant factors from Minnesota's resource-planning and certificate-of-need statutes, Minn. Stat. §§ 216B.2422 and .243."

As indicated in the Department's March 5, 2019 comments one of the governing statutes for Xcel's proposed transaction is Minnesota Statutes § 216B.50, which states in part "If the Commission finds that the proposed action is consistent with the public interest, it shall give its consent and approval…" One of the criteria in this proceeding is the same as the criterion relied upon by the Commission to apply the renewable preference consideration in the NTEC proceeding and, in addition, this proceeding clearly involves resource planning and resource acquisition aspects; thus, the Department concludes that the considerations of Minnesota Statutes § 216B.2422 apply here as well.

Minnesota Statutes § 216B.2422, subd. 4 states:

> The Commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the Commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest. When making the public interest determination, the commission must consider:

1) whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02, the renewable energy standard under section 216B.1691, or the solar energy standard under section 216B.1691, subdivision 2f;
2) impacts on local and regional grid reliability;
3) utility and ratepayer impacts resulting from the intermittent nature of renewable energy facilities, including but not limited to the costs of purchasing wholesale electricity in the market and the costs of providing ancillary services; and
4) utility and ratepayer impacts resulting from reduced exposure to fuel price volatility, changes in transmission costs, portfolio diversification, and environmental compliance costs.

C. XCEL'S UNREASONABLE RESOURCE PLANNING APPROACH

1. Summary

The Department's March 5, 2019 comments largely concluded that Xcel had not demonstrated that its proposal was reasonable.[3] As to Xcel's modeling regarding need, since the proposed amount of intermediate capacity was greater than the amount approved in Xcel's prior IRP,[4] that IRP analysis couldn't be used to assess whether Xcel's proposal was reasonable. Still, the Department attempted to use the database from the last IRP, but Xcel's assumptions about key inputs[5] were outside of the bounds used in the IRP, so that approach was not feasible.[6]

> Thus, the Department attempted to use Xcel's proposed database in this proceeding to assess the reasonableness of the Company's proposal. However, the Department identified a number of fundamental flaws with Xcel's initial modeling. For example, as discussed further below, Xcel made unrealistic assumptions about how their resources would be used, which artificially inflated the value of MEC, and undervalued resources such as energy conservation.

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[3] The Department did recommend that the Commission approve a variance to Minnesota Rules 7825.1800, subp. B to allow Xcel to not provide the information set forth in Minnesota Rules 7825.1400, items (A) through (J).
[4] Docket No. E002/RP-15-21; capacity amounts were particularly higher after 2026.
[5] The key inputs were the demand forecast, energy forecast, Sherco coal prices, and natural gas prices for MEC I and Riverside.
[6] In addition, Xcel retired and added resources to its system since the last IRP was approved.

Xcel's initial modeling flaws were serious. However, rather than recommending denial of Xcel's petition, the Department recommended that the Commission "take no action on the Company's requests to approve the acquisition of Southern's MEC I and MEC II property, under Minnesota Statutes § 216B.50, as Xcel has not shown its proposal to be reasonable." The expectation was that Xcel would remedy those modeling issues in reply comments.

However, as discussed below, Xcel did not remedy these issues in reply comments. Instead, Xcel's second set of modeling was also flawed. Xcel provided another attempt to model its system appropriately, but that approach also failed. The Department gave Xcel yet another opportunity to demonstrate the reasonableness of its proposal. As indicated below, even in this fourth opportunity to make its case for acquiring MEC, Xcel's modeling assumptions continue to be invalid and inappropriately inflate the value of MEC.

2. Xcel's Initial Model—Spot Market Pricing

a. Overview

Regarding spot market pricing, the Company's reply comments did not adequately address the modeling concerns about how Xcel disaggregated the monthly average energy prices to create its monthly price curves. As discussed further below, the Department continues to conclude that Xcel's market price shapes represent a contingency that it is a significant departure from past and present market relationships, which should not be used as the basis to approve Xcel's proposal since basic analysis of publicly available Midcontinent Independent System Operator, Inc. (MISO) data indicates that no such relationship exists at this time.

b. MISO Energy Market Background

Basic information about the wholesale energy market operated by the MISO is helpful to understand Xcel's modeling flaws. MISO states that it "ensures reliable, least-cost delivery of electricity across all or parts of 15 U.S. states and one Canadian province."[7] MISO also ensures that resources needed to serve load across its system are dispatched in the most economically efficient manner; in this role, MISO uses prices across its system, called locational marginal prices (LMPs).

In MISO's energy market the LMP consists of three elements, the cost of energy, the cost of congestion, and the cost of line losses. While the cost of congestion and the cost of line losses are site-specific, the cost of energy is the same everywhere in MISO. Most of the time the largest component of the LMP is the cost of energy. As structured by MISO, the cost of energy is determined by the last unit dispatched to meet load; the marginal unit.

[7] Source: https://www.misoenergy.org/about/.

Conceptually, in MISO's operations generating units are stacked in cost order with the units having the lowest variable cost per MWh at the bottom of the stack and are dispatched first. The units with the highest variable cost per MWh are at the top of the stack and are dispatched last, only if needed to serve load. While there are always exceptions, generally speaking wind units would be at the bottom of the generating stack as they have low or even negative variable costs. The remaining units in the dispatch order (arranged roughly in expected cost order) would be nuclear, coal, natural gas, and then oil-fueled units.

c. Xcel's Flawed Assumptions about Renewable Energy Driving MISO's Energy Prices

Given this understanding of MISO's operations, Xcel's assumptions about how their resources would be used in the MISO market are not realistic or supportable, either in the Company's initial or subsequent modeling. For example, Xcel assumed in their initial modeling that peaking units would be overused, in an uneconomic manner. However, since MISO dispatches resources in an economic manner, Xcel's assumption is not valid. Further, lower cost options should be available to Strategist to reduce the uneconomic generation from the peaking units.

Moreover, as the Department pointed out in our Comments, Xcel's initial assumptions about how intermediate units would be used artificially inflated the value of MEC, while artificially undervaluing resources such as energy conservation:

> The more efficient intermediate units have capacity factors in the range of 50 to 75 percent from 2027 to the end of the run in 2057. Typically, when capacity factors for intermediate units exceed 40 to 50 percent on a consistent basis it is also an indication that additional energy-producing units will be economic.
>
> These high capacity factors represent a problem because Strategist is an economic model. When units operate in an uneconomic manner the model will use whatever tools are available to mitigate the uneconomic operations. In this case, the only tools available to Strategist are increased generation from existing units. Thus, all existing, dispatchable units—including MEC—will be perceived by the model as having benefits in that they can produce more energy, mitigating uneconomic operations of units higher in the dispatch order. However, in the future such benefits are unlikely to be realized because a full range of potential mitigation measures—addition of new supply units, additional conservation, and so forth—will be tested.

> Thus, here Xcel's Strategist base case perceived a benefit to running an intermediate unit at a 70 percent capacity factor because that result avoids operating a more expensive peaking unit. However, in reality the intermediate unit will not operate at such a high capacity factor because other, lower cost solutions to the excessive use of peaking units will be found. Thus, the benefits to high use of intermediate units such as MEC—to avoid operation of more expensive peaking units—are merely an artifact of Xcel's modeling process. [footnote omitted][8]

Xcel's invalid assumptions about the use of their resources in the MISO energy market continued in the Company's most recent models. The Department pointed out in our initial comments (starting on page 22, "Table 7 database—with Spot Market on") that significant problems with Xcel's analysis stemmed from:

1) the fact that Xcel's assumptions about the amount of energy bought and sold in the MISO spot market was a dominating factor as to whether the purchase of MEC I and MEC II was reasonable,
2) Xcel's assumption as to when MISO's energy prices would be high and low were not reasonable or supportable (e.g. that MISO's LMP energy prices would be highest in the spring rather than summer, and that LMPs would be *lowest* during peak hours), and
3) Xcel allowing only these unreasonable assumptions about MISO's LMPs to be considered in the analysis.

Assumptions about the spot market should not have such a significant effect on the question of whether acquisition of a resource is reasonable, in part because utilities should not assume that retail ratepayers would have to pay for a resource that is expected to be used to sell material amounts of power into the MISO energy market rather than being largely used to serve retail load. Further, when the assumptions about the pattern of prices in the MISO energy market do not make sense, concerns about the influence of the spot market on the decision to acquire a resource are exacerbated. Thus, the Department's initial comments stated that, given:

> - the significant role played by selling energy into the spot market;
> - the curious pricing structure used by Xcel; and
> - the lack of contingencies or alternative pricing structures;
>
> the Department recommends that the Commission not make any decisions based upon use of Xcel's Strategist model where the spot market is in use. In essence, the Department concludes that the structure of the inputs does not appear to be a reasonable forecast

[8] Department's March 5, 2019 comments, pages 21-22.

> of the future and the Department is not aware that alternative pricing structures were explored by the Company via contingency analyses.

Since these observations pointed to inappropriate modeling, the Department fully expected Xcel to remedy these concerns in their reply comments. However, the Company's reply comments instead defended Xcel's approach. Specifically, Xcel explained that it receives forecasts of monthly average on-peak and off-peak LMPs at the Minnesota hub from other entities. The Department agreed that Xcel's average monthly prices appeared to be reasonable but had significant concerns with Xcel's assumed disaggregation of the prices to create the hourly prices in the price curves for each month.

At issue here is Xcel's method for creating the hourly price curves within the months. Xcel explained its method as follows:

> We then use that market data to create an hourly shape for each month based on the amount of thermal units generation dispatched on our system. The methodology results in lower hourly LMPs during times when significant amounts of renewable energy is on the system and higher hourly LMPs when lower amounts of renewable energy is available on our system.

This statement demonstrates that Xcel's method assumes that renewable output directly impacts market prices. In other words, Xcel assumes that the LMPs can largely be determined by the amount of renewable power that is produced in each hour of the month. However, Xcel's market price shapes represent a significant departure from past and present market relationships. There may be a potential future where LMPs exhibit a strong, inverse correlation with renewable energy output. However, basic analysis of publicly available MISO data indicates that no such relationship exists at this time.

Moreover, the Department would expect the amount of wind generation to be inversely correlated with the amount of natural gas and coal generation because more wind generation at the bottom of the resource stack will displace natural gas and coal units further up the dispatch stack. Since the LMP is determined by the last unit dispatched, the amount of natural gas and coal generation should be directly correlated with LMPs since they often are the last units dispatched and the more natural gas generation on line, the more expensive the last unit and thus the higher the LMP.

From the dispatch stack it is clear that that wind units should be setting the LMP for relatively few hours in a year. Thus, the expectation is that wind generation would be poorly (inversely) correlated with LMPs because there is an intervening unit between wind output and the LMP. More wind generation causes lower cost units to be on the margin, and those lower cost units result in reduced LMPs hence the inverse correlation. However, most often the LMP would be set by coal and natural gas units and those units should exhibit a stronger, direct correlation. As a result, LMPs should not largely be determined by the amount of renewable power that is produced in each hour of the month.

To assess the validity of Xcel's analytical technique of using wind generation to drive spot market pricing, the Department analyzed MISO's data. The variables of interest are the hourly Minnesota hub LMPs and the hourly wind generation in MISO-north.[9] The results of the correlation coefficient calculations[10] for the last four years (on a monthly basis) are summarized as follows:

- 2015: strongest monthly correlation -0.51, weakest monthly correlation -0.13, 2 months stronger than -0.50 (October and November).
- 2016: strongest monthly correlation -0.51, weakest monthly correlation -0.13, 1 month stronger than -0.50 (December).
- 2017: strongest monthly correlation -0.51, weakest monthly correlation -0.28, 1 month stronger than -0.50 (November).
- 2018: strongest monthly correlation -0.48, weakest monthly correlation -0.13, no months stronger than -0.50.

Since the correlation coefficients are not close to 1.0, they indicate that there is not a significant relationship between the amount of wind generation in MISO-north and Minnesota hub LMPs. Also, there is no clear trend in the correlation coefficients over time. Based upon the discussion of the MISO dispatch routine above, this result is expected. Thus, Xcel's market pricing assumptions are not borne out by the data and there is no trend that might indicate that Xcel's assumptions will be valid in the future.

That leaves two questions to be answered:

1. Is the amount of wind generation correlated to coal and gas generation as expected?
2. Is the amount of coal and gas generation correlated with LMPs as expected?

In this case wind generation in MISO-north and gas generation in MISO-north tend to exhibit a strong, inverse correlation (wind and natural gas generation move in opposite directions),

[9] The underlying data is from MISO's real-time market and not the day-ahead market.

[10] A correlation coefficient is a statistical calculation that shows the degree of relationship between two variables. The calculation results in a number between −1 and +1. Simply put, a positive value indicates that the two variables tend to move in the same direction, a direct relationship. A negative value indicates that the two variables tend to move in the opposite direction, an inverse relationship. The closer the correlation coefficient is to −1 or +1 the stronger the (direct or inverse) relationship. The closer the correlation coefficient is to zero, the weaker the (direct or inverse) relationship.

especially in non-summer months.[11] Similarly, wind generation in MISO-north and coal generation in MISO-north also tend to exhibit a strong, inverse correlation in non-summer months.[12] Thus, the correlation coefficients indicate that the Department's understanding of MISO's dispatch is correct.

Finally, the Department notes that the levels of coal generation in MISO north and natural gas generation in MISO north are directly correlated with Minnesota hub LMPs. As an example, the correlation coefficients between coal and LMPs are summarized as follows:

- 2015: strongest monthly correlation 0.75, weakest monthly correlation 0.36, 9 months stronger than 0.50.
- 2016: strongest monthly correlation 0.70, weakest monthly correlation 0.38, 10 months stronger than 0.50.
- 2017: strongest monthly correlation 0.65, weakest monthly correlation 0.42, 7 months stronger than 0.50.
- 2018: strongest monthly correlation 0.60, weakest monthly correlation 0.32, 5 months stronger than 0.50.

Overall, the correlation coefficients show that, in the recent past, increased wind generation displaces coal and gas generation and changes in coal and gas generation impact LMPs. Note that the relationship between coal generation and LMPs was weaker the last two years. Thus, it is possible that renewable generation may reach levels where wind output directly impacts LMPs rather than impacting generation from dispatchable (coal and gas) resources which in turn determine the LMPs. However, at this time it is not reasonable to assume that the hourly LMPs can be determined each month by the amount of wind energy generation.

d. Summary of MISO Market Pricing

In summary, MISO's data indicate that wind generation does not directly impact LMPs as Xcel assumes. Instead wind generation displaces other, dispatchable generation. Those other generation types (coal and natural gas) then set the LMPs. Because wind impacts LMPs only indirectly—through changes in coal and gas generation—it is not reasonable to assume that changes in wind output significantly impact LMPs, at least not at this time or with the available data. Therefore, given Xcel's failure to provide reasonable spot market pricing inputs, the recommendation from the Department's Comments still applies:

[11] The wind-gas correlation coefficient was stronger than -0.50 as follows 2015: 8 months, 2016: 9 months, 2017: 6 months, and 2018: 10 months.
[12] The wind-coal correlation coefficient was stronger than -0.50 as follows 2015: 9 months, 2016: 10 months, 2017: 10 months, and 2018: 8 months.

Overall, given:

a. the significant role played by selling energy into the spot market;
b. the curious pricing structure used by Xcel; and
c. the lack of contingencies or alternative pricing structures;

The Department continues to recommend that the Commission not make any decisions based upon use of Xcel's Strategist model where the spot market is in use.

3. Review of Modeling in Reply Comments

a. Overview

The Department attempted to use Strategist to review Xcel's modeling efforts in the Company's reply comments. The Department uses the following general process when reviewing Strategist modeling:

1. obtain from the company a base case file, and the commands necessary to recreate the various scenarios explored by the Company;
2. re-run the company's base case file to make sure the outputs match and that the Department is working with the correct file;
3. review the company's base case's inputs and outputs for reasonableness;
4. create a new Department base case, to include any changes needed to the company's base case;
5. run scenarios of interest on the new base case to explore various risks and alternative futures;
6. assess the results of the scenarios and establish a new preferred case; and
7. run scenarios of interest on the new preferred case to test the robustness of the Department's preferred case.

The Department's overall goal in reviewing utility modeling efforts is to determine if the proposed plan—or in this case, resource acquisition—results in a reliable, low cost, low environmental impact system that reasonably manages risk. In this case the continuing time restrictions due to Xcel's initial request for a speedy decision and subsequent short time extensions prevented the Department from attempting to establish a new base case and running separate scenarios.

b. Xcel's Strategist Process

When reviewing modeling performed by Xcel a complication arises from the fact that the Company's usual practice is to download all Strategist outputs into an Excel spreadsheet and then re-calculate the cost of the scenario. Verification of Xcel's complex process requires obtaining the Excel files into which the Company downloaded the Strategist data, comparing

Xcel's Excel files to the values in the Petition to ensure that the correct Excel files have been obtained, then comparing Xcel's Excel files to Xcel's Strategist files to ensure that the correct Strategist files have been obtained. Thus Xcel:

- runs Strategist;
- downloads the outputs into an Excel spreadsheet;
- re-calculates the cost of the scenario; and
- puts the re-calculated cost into the Company's Petition.

This process is cumbersome and is not followed by any other utility. The complexity of Xcel's process requires the Department to re-run Strategist and compare the Department's Strategist outputs to Xcel's Strategist outputs. Then the Department must compare the Department's Strategist outputs to the outputs in Xcel's Excel files. Finally, the Department must compare the costs calculated in Xcel's Excel files to those in the Company's petition. While the Department does not necessarily object to this process, it requires significant time for verification, creates significant complications and leaves the Company in a position where the large number of steps increases the probability of mistakes. As discussed below, it appears that errors occurred in this case.

c. Department Review

Along with the reply comments, Xcel provided the Department with the Strategist base case file, the files used to adjust the base case for contingencies, and the Excel spreadsheet files used by the Company to process the Strategist results. In response to Department Information Request Nos. 12 to 17, Xcel provided a guide on how to use the Company's files to obtain the results shown in Tables 4 to 9 of the Company's reply comments.

As explained above the Department's first step is to re-run the Company's base case file to make sure the outputs match. In this case, the Department ran numerous scenarios in an attempt to match as many of the cases analyzed by the Company as possible. The original goal was to limit the time required by relying strictly on the Company's analysis. However, in this case the Department was almost able to match the Company's results for only one scenario—the base case. In the base case the results matched for the expansion plan, total variable costs, total emissions costs, and fixed costs except for the fixed costs associated with the Monticello and Prairie Island generating units. The fact that the expansion plan and variable costs matched is key as that fact indicated that, most likely, the differences between the Department's and Xcel's runs were confined to fixed costs. This outcome is important because matching everything except fixed costs means that the number of potential expansion plans Strategist analyzes for the Department is likely correct.

While in normal circumstances, the Department would have worked with Xcel to identify the issues causing the widespread difference in results, doing so was unnecessary in this case because Xcel's overall resource planning approach embodied in reply comments contains a fundamental flaw.

One thing that stood out immediately from the Department's work was the length of time necessary for Strategist to complete a run. While normally a Strategist run can be completed in 20 minutes or less, runs on Xcel's Strategist files were taking one to three days, with the three-day length being a common result. At that rate, matching the approximately 150 results in the Company's reply comments would take the Department about two months, if everything went correctly the first time.[13] Such circumstances were not acceptable since the analysis could not be completed in a timely manner.

Nor was it possible for the Department to develop its own base case, since that process would take several months at a minimum. This process, again due to the time required, would not be acceptable. Thus, the Department concluded that there was no acceptable path to analyze the Company's Strategist database.

However, the Department investigated why Strategist was taking so long to arrive at a solution and discovered the reason to be that the Company's inputs required far too many potential plans to be analyzed by Strategist. Such circumstances are concerning since it leads to Strategist inappropriately discarding possible reasonable solutions.

Conceptually, the process used by Strategist regarding creating, analyzing, and saving expansion plans[14] is as follows. First, Strategist takes the expansion plans saved at the end of the prior year, checks to see if any expansion units are allowed to be added in the current year given the inputs provided by the modeler,[15] and creates as many potential plans as the expansion units make possible. Second, the potential plans are then run through certain screening criteria set by the modeler, such as minimum and maximum: reserve margins, emergency energy, and so forth.[16] Third, the potential plans that meet the screening criteria are run through the model's dispatch routine and total costs are calculated for each surviving potential plan. Fourth, if the number of surviving potential plans exceeds the limit of the model's database (here equal to 2,500 plans[17]) the potential plans are ranked based upon cost and all plans in excess of the database limit are dropped and not considered further.

[13] In the Department's experience things rarely go correctly the first time.
[14] Note that in Strategist an expansion plan is referred to as a "state."
[15] For example, the modeler might make a wind unit available in 2020, but not in 2021. So, the wind unit creates a potential expansion plan in 2020, but not in 2021.
[16] Emergency energy represents energy requirements not met by the model inputs (the utility's system and the spot market) even though the utility's system was able to meet minimum capacity requirements.
[17] The Company's version of Strategist can retain 2,500 plans at the end of any one year. Other values are possible depending on user preferences as Strategist's vendor tailors the size of the database to the user's request.

Omitting potentially viable plans that are cost effective when all years are considered is not appropriate. Moreover, the earlier in an expansion plan that a potential plan is omitted, the more potential solutions that are arbitrarily excluded from consideration.

Even in the case where the Department was reasonably sure that the files were correct—the base case[18]—the Company exceeded the maximum number of plans for the first time in 2030 and exceeded the 2,500 plan limit in most years thereafter.[19] In one year (2035) the number of potential plans exceeded 800,000. Even allowing for plans to be discarded by Strategist after using the screening criteria, it is clear that Strategist was required to discard a half-million or more potentially reasonable plans based upon the arbitrary criteria that such plans had too high a cost in 2035 (Xcel runs Strategist through 2057). The same conclusion can be reached in other years. Strategist reported exclusion of in excess of 100,000 potential plans in 2035, 2041, 2046, 2048, 2049, and 2054.

Thus, the issue in reply comments was Xcel forcing Strategist to evaluate too many plans. Given that this issue is not new and is well known to Xcel, it is troubling that the Company chose to use this approach in their reply comments.

d. Fundamental Planning Flaw

Behind this problem is Xcel's failure to use a valid resource planning process. In this case, Xcel did not employ a reasonable process for reviewing potential expansion units to determine if they should be entered into Strategist. Such a process is a vital step in IRPs where new resources may be needed and Strategist will be used. For two examples of screening analysis, Xcel can refer to the qualitative review of potential alternatives employed by Otter Tail Power Company (OTP); see Docket No. E017/RP-16-386 at Appendix D of OTP's IRP petition and the quantitative review employed by ALLETE, Inc., doing business as Minnesota Power (MP); see Docket No. E015/RP-15-690 at Appendix K of MP's IRP petition.

The fact that Xcel did not recognize the need to employ a formal screening process prior to using Strategist does not mean that a screening analysis did not take place at all. It only means that Xcel employed a tool—here Strategist—that is utterly unequipped to perform that function in a reasonable manner.

This failure in screening potential expansion units evidently led Xcel to include numerous alternatives that serve the same function. For example, in 2030 Xcel made available at least three different expansion units (different technologies) that serve the same peaking function.

[18] Represented in Company's reply comments, Table 4 at row 1, column 1, page 24, with continuation of the PPAs, and market sales off.
[19] The Department does not know for certain the number of excess plans as the information Strategist reported that was referenced by the Department reports the number of potential plans and the number of saved plans, but does not include the number of plans that passed the screening criteria (were feasible).

Choosing a specific technology to meet a need for peaking resources is not the function of a resource plan. Instead, the resource plan only determines the size, type, and timing of the need. Selecting the best overall technology is the function of the resource acquisition process, which occurs at a later date.

Xcel's failure to recognize the need for a screening analysis was compounded by the Company's inability to use the superfluous designation in Strategist appropriately.[20] Rather than target the use of the superfluous designation to years and units in which it might significantly impact the overall IRP results, Xcel gave every wind unit and every solar unit a superfluous designation. This completely unnecessary approach to use of the superfluous designation creates a large increase in the number of potential plans Strategist must consider.

Finally, Xcel's failures to employ proper resource planning techniques was further compounded by the Company's failure to use the modeling technique of multiple runs to a significant extent: one set of runs with a unit forced into the expansion plan and a second set of runs not allowed in the expansion plan. This technique limits the number of potential plans the model must consider and can provide the IRP with more detailed data. For example, this approach allows the modeler to see exactly how much more expensive a particular expansion unit is. When an expansion unit is offered as an option the only information that results is whether the expansion unit was or was not least cost. A further potential benefit to the run with and without technique is that it can be quicker to do two runs with a unit allowed/not allowed than one run with an option.

Thus, the process Xcel used here resulted in far too many potential plans for Strategist to consider. This process error, forcing Strategist to perform the task of screening alternatives, is a task the model is not suited for since the model uses an arbitrary criterion for sorting out potential plans and reducing them to the allowed number.

Finally, the Department notes that in the Company's 2015 IRP, the Company held a series of workshops. At the April 8, 2015 meeting—held in the Commission's small hearing room—Xcel gave a presentation on Strategist modeling. Attachment 1 to these comments provides selected pages from Xcel's presentation, which demonstrate that Xcel was aware of at least some of the issues above. Pages 22 to 24 of the presentation outline the importance the Company placed (at least in 2015) on limiting the number of options considered to constrain the problem presented to Strategist to a manageable level. Apparently Xcel no longer believes it is necessary to constrain the problem to the level that Strategist can handle and instead believes it is reasonable to discard potentially superior solutions. Xcel's failure to limit the

[20] Briefly, the superfluous designation allows a potential expansion unit to be considered based upon energy needs rather than only being considered when capacity is needed. That is, normally an expansion unit is only tested when a capacity deficit is present. A superfluous means the unit will be added (create a new potential expansion plan) in all circumstances. The superfluous designation can be helpful in some circumstances but greatly increases the number of potential expansion plans.

number of alternatives evaluated in Strategist renders invalid the results provided in the Company's reply comments for the reasons discussed above.

e. Summary of Reply Comment Modeling

In summary, given the arbitrary nature of the results of Xcel's resource planning process, the Department recommends that the Commission give no weight to results produced by the resource planning processes and Strategist data used by the Company in reply comments.

4. Xcel's First Supplemental Modeling

a. Overview

The Company's Response to Department Informal Information Request No. 1 provided a third set of modeling results where Xcel attempted to provide an adequate resource planning background for the MEC acquisition. The modeling results included a Strategist base case file, macros that adjust the Strategist base case file to analyze contingencies, and Excel files that contain the outputs from Strategist runs using the Strategist base case and macro files provided by Xcel.

The Company provided files that created the following eight scenarios:

- MEC remains under the existing PPAs;[21]
- Xcel purchases MEC and operates the units until 2046 and 2054;[22]
- Xcel purchases MEC and retires MEC in 2050;
- Xcel purchases MEC and retires MEC in 2040;
- MEC remains under the existing PPAs and existing coal units retire early;
- Xcel purchases MEC, operates MEC until 2046 and 2054, and retires existing coal units early;
- Xcel purchases MEC, retires MEC in 2050, and existing coal units retire early; and
- Xcel purchases MEC, retires MEC in 2040, and retires existing coal units early.

[21] The MEC I PPA expires in 2026, the MEC II PPA expires in 2039.
[22] In this scenario MEC operates as 2x1 combined cycle unit into 2046 and as a 1x1 combined cycle unit into 2054.

Xcel ran each of the eight scenarios 13 times to analyze the following contingencies:

- Xcel Base Conditions—High Externalities, High Costs of Complying with CO_2 Regulations (High Regulatory Costs);[23]
- Change: No Externalities, No Regulatory Costs, No Capacity Market Revenue/Cost;
- Change: No Externalities, No Regulatory Costs;
- Change: Low Externalities, Low Regulatory Costs;
- Change: Mid Externalities, Mid Regulatory Costs;
- Change: Low Externalities, No Regulatory Costs;
- Change: High Externalities, No Regulatory Costs;
- Change: Low Natural Gas/Spot Market prices;
- Change: High Natural Gas/Spot Market prices;
- Change: Low Energy and Demand Requirements;
- Change: High Energy and Demand Requirements;
- Change: High MEC Operation and Maintenance (O&M)/Capital Costs; and
- Change: Low MEC O&M/Capital Costs.

Xcel ran the suite of 104 runs once with the spot market available and again with the spot market turned off.

b. Department Review

The Department encountered significant errors by Xcel in each step of the analysis.

First, the Department briefly reviewed Xcel's assumed Strategist spot market pricing inputs in the Company's response to the Department's Informal Information Request No. 1. Unfortunately, Xcel did not correct the errors discussed above and instead used the same flawed inputs that were present in the database Xcel used for the Petition. (For example, Xcel's initial modeling resulted in uneconomic dispatch of Xcel's generation facilities by Strategist.) Thus, again, Xcel's assumptions are not valid. As a result, the Department did not consider any of the Company's Strategist analysis with the spot market available. Thus, the remaining review in this section focuses on scenarios with the spot market unavailable.

Second, the Department again ran numerous scenarios in an attempt to match as many of the cases analyzed by the Company as possible. As before, the goal was to limit the time required by relying on the Company's analysis. Once again, the Department was *almost* able to match the Company's results for the base case. The Department ran Strategist using the input files

[23] Note that Xcel assumes that changes in both natural gas prices and the Commission's CO_2 internal cost value have a subsidiary impact on the spot market price based upon assumptions regarding heat rate and fuel of the marginal unit in MISO. This is a common approach in Strategist modeling; however, for simplicity this list does not note this subsidiary change.

provided by Xcel and then compared the Department's Strategist outputs to Xcel's Strategist outputs as documented in the Excel files provided by the Company. For the base case the results matched for the expansion plan, total variable costs, total emissions costs, and fixed costs except for Xcel's fixed costs associated with a capital spending project referred to in Strategist as "SYNC." The cost of the SYNC project was different in the outputs provided by Xcel and the outputs the Department obtained from using the inputs provided by Xcel.

While the Department did not check all runs for a difference in the SYNC capital spending project, every check showed a difference due to Xcel's mysterious SYNC capital spending project. As noted above, most often the Department does not consider a difference in fixed costs, on its own, to be a significant issue. While clearly it would be preferable for the costs to be the same, a fixed cost difference is typically not significant because examining the differences between two Strategist runs with the fixed costs (even if the costs are wrong) will net to zero.

By contrast, fixed costs are significant if they change between two scenarios, for example, due to comparing a run with a standard retirement date to a run with an early retirement date. The input in question was not changed in the commands that create the various contingencies. Thus, the base case (*.FSV) file provided by Xcel was different from the file Xcel actually used to create the outputs; that is, the files Xcel provided did not adequately support its analysis.

Third, four of the eight scenarios involved examination of the impact of early coal unit retirement:

- MEC remains under the existing PPAs and existing coal units retire early;
- Xcel purchases MEC and retires existing coal units early;
- Xcel purchases MEC, retires MEC in 2050 and retires existing coal units early; and
- Xcel purchases MEC, retires MEC in 2040 and retires existing coal units early.

In every case examining early coal unit retirement (4 scenarios, 13 contingencies each) the Department's run encountered an error related to the changes Xcel made to inputs regarding two capital spending projects, which Xcel called "NUKE_LBC" and "COAL_LBC."[24] Further, the error prevented Strategist from including these capital spending costs in the overall costs to be analyzed, even though the inputs indicate that Xcel intended for the capital spending costs to be included, since Xcel set up a transfer process in the inputs for these runs.[25] Finally, when the

[24] Again, Xcel did not adequately describe these proposed capital projects so the Department could not assess whether Xcel's inclusion of these variables was reasonable.
[25] As discussed above, Xcel's practice is to download Strategist results into an Excel spreadsheet and recalculate the costs for reporting in petitions. Note that this process could create significant inconsistencies between the

Department attempted to download the Strategist results into Excel spreadsheets for recalculation and comparison to Xcel's Excel files, the errors prevented the data from being downloaded. In summary, all 52 runs involving early coal retirement failed due to errors in Xcel's underlying files implementing early retirement.[26]

Fourth, one scenario involved Xcel purchasing MEC but then shutting down the facility in 2040. The Department was unable to match the Company's results in all 13 runs. The difference appears to be attributable to different units that Xcel added in the expansion plan, beginning in 2032, 2035, or 2041 depending on the specific contingency in question.[27] Thus, none of Xcel's analysis of purchasing MEC and shutting the facilities down in 2040 can be verified.

Fifth, one scenario involved Xcel purchasing MEC but then shutting down the facility in 2050. Again, the Department was unable to match the Company's results in all 13 runs. The difference appears to be attributable to different units Xcel added in the expansion plan, beginning in 2032, 2035, or 2048 depending on the specific contingency in question.[28] Thus, none of Xcel's analysis of purchasing MEC and shutting the facilities down in 2050 can be verified.

Thus, in six of Xcel's eight scenarios the Department's efforts to use Xcel's inputs to obtain Xcel's outputs failed in all 13 contingencies. These failures indicate widespread problems on the part of Xcel as to identifying the inputs the Company used to create a given set of outputs. In essence, Xcel evidently has some combination of lack of organization and lack of adequate controls over access to the files.[29]

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costs that Xcel reports in petitions and the costs actually minimized by Strategist. However, since the Department was unable to satisfactorily match the Company's results due to inconsistencies in the underlying files, the Department did not pursue the potential for the Company's Strategist-to-Excel process to create even further inconsistencies.

[26] The files containing the errors are labeled:

- _Control_Mankato Own_EC_HRE.INP;
- _Control_Mankato Own_EC2040_HRE.INP;
- _Control_Mankato Own_EC2050_HRE.INP; and
- _Control_Mankato PPA_EC_HRE.INP.

[27] The files likely to contain errors for this set of runs are labeled:

- _Control_Mankato Own_2040_HRE.INP;
- SENS_FD_MKTOFF_LOWLOAD.INP; and
- SENS_FE_MKTOFF_HIGHLOAD.INP.

[28] The files likely to contain errors for this set of runs are labeled:

- _Control_Mankato Own_2050_HRE.INP;
- SENS_FD_MKTOFF_LOWLOAD.INP; and
- SENS_FE_MKTOFF_HIGHLOAD.INP.

[29] In previous IRP proceedings this lack of reasonable organization was not an issue as the Department only needed to match the base case and then performed the Department's own modeling starting with the base case file. In the current proceeding, given Xcel's assertions that Commission decisions were needed quickly, such analysis was not possible.

Sixth, one scenario involves Xcel purchasing MEC and operating the unit to the end of the expected life (2054). When running the inputs for this scenario the Department matched Xcel's outputs—except for a small difference likely attributable to the SYNC project discussed above—in all contingencies except two: low load and high load. The difference in the two load contingencies is attributable to a difference in units added in the expansion plan starting in 2032 and 2035 respectively. It is unclear why this difference occurred or how this difference influenced the results.

Seventh, one scenario involved Xcel continuing the PPAs with MEC. When running the inputs for this scenario the Department matched Xcel's outputs—except for a small difference likely attributable to the SYNC project discussed above—in all contingencies except four: low load, high load, low MEC costs, and high MEC costs. The difference for the load contingencies is attributable to a difference in units added in the expansion plan starting in 2034 (low load) and 2032 (high load) as discussed just above.

The difference for the MEC cost contingencies is attributable to a difference in the overall cost of capital spending projects. The Department identified a capital project labeled "74 - 0" as the ultimate source of the difference in both instances (Low MEC Costs and High MEC Costs). It is not clear why capital costs would matter in a scenario where Xcel continues with the PPAs because capital costs would be the responsibility of the owner (currently Southern). However, that is what the files provided by the Company indicate.

The Department notes that the widespread discrepancy in inputs used by Xcel versus the inputs provided to the Department was part of a larger pattern throughout this proceeding: the Company has been unable to provide sets of files where the inputs Xcel provided to the Department created the outputs provided to the Department.[30] In other words, Xcel has been unable to "show its work" accurately.

In summary, the Department concludes that, while a handful of the Company's modeling results, as provided in response to Department Informal Information Request No. 1, might be accurate the overall data control on the part of Xcel is so poor that there is no reason to conclude that the inputs and outputs agree only because they both contain the same mistake. Therefore, the Department did not proceed to the remaining steps in the analytical process.

Overall, the Department concludes that Xcel's response to Department Informal Information Request No. 1 failed to demonstrate that conditions have changed significantly since the Company's most recent IRP (Docket No. E002/RP-15-21). The Minnesota Legislature already determined that the need for intermediate capacity and energy identified by the Commission in

[30] If the Company desires to address this inconsistency issue it should consider steps such as limiting access to Strategist files by Xcel personnel, putting all files required by a run or set of runs in a single folder, eliminating the recalculation of costs in the Excel files, and reporting in the Petition the values reported by Strategist for present value of revenue requirements (PVRR) and present value of societal costs (PVSC).

that IRP would be met by a new combined cycle unit to be located at the Sherburne County Generating Station (Sherco) site.

Specifically, Minnesota Law 2017, Chapter 5 states, in part:

> Notwithstanding Minnesota Statutes, section 216B.243 and Minnesota Statutes, chapter 216E, a public utility may, at its sole discretion, construct, own, and operate a natural gas combined cycle electric generation plant as the utility proposed to the Public Utilities Commission in docket number E-002/RP-15-21, or as revised by the utility and approved by the Public Utilities Commission in the latest resource plan filed after the effective date of this section, provided that the plant is located on property in Sherburne County, Minnesota, already owned by the public utility, and will be constructed after January 1, 2018.

Not being located in Sherburne County, or on property already owned by Xcel,[31] the MEC units do not qualify under the above provision and Xcel has not demonstrated a need for further intermediate capacity. Since the above provision is in Minnesota law, approving Xcel's proposed MEC purchase would unreasonably expose Xcel's ratepayers to paying for both MEC and the natural gas combined cycle electric generation plant units at Sherco, which Xcel may, "at its sole discretion, construct, own, and operate."

c. Summary of First Supplemental Modeling

In summary, given Xcel's inability to provide input and output files that are consistent with each other, the Department concludes that Xcel did not adequately support its own analysis in the Company's response to Department Informal Information Request No. 1. Thus, the Department recommends that the Commission give no weight to results in the Company's response to this information request.

5. Second Supplemental Modeling

a. Overview

The Department gave Xcel yet another opportunity to demonstrate that its proposal was reasonable. The Company's Response to Department Informal Information Request No. 2 provided the Department a fourth set of modeling results attempting to provide an adequate resource planning background for the proposed MEC acquisition. This time Xcel included a Strategist base case file, macros that adjust the Strategist base case file to analyze

[31] Further, MEC I was constructed long before January 1, 2018.

contingencies, macros that demonstrated exactly how Xcel ran Strategist, and Excel files that contained the outputs from Strategist runs using the Strategist base case and macros.
The files the Company provided appeared to create the same eight scenarios as in Department Informal Information Request No. 1. Once again, each of the eight scenarios was modified to analyze the same 13 contingencies. As before, Xcel ran the suite of 104 runs (8 scenarios times 13 contingencies) once with the spot market turned off and again with the spot market available.

b. Department Review

i. Initial Analytical Steps

Again, Xcel's analysis contained numerous material flaws. The following describes issues the Department encountered in reviewing Xcel's analysis.

First, the Department again briefly reviewed Strategist's spot market pricing inputs. It appeared that the same flawed inputs that were present in the database used for the Petition were also used in the database used for the 2nd set of supplemental files. Therefore, the Department did not consider any of the Company's Strategist analysis where the spot market was turned on. The remaining review in this section focuses on the scenarios with the spot market off.

Second, the Department again ran numerous scenarios to try to match as many of the cases analyzed by the Company as possible, to try to rely on the Company's analysis. The process was the same as before; the Department ran Strategist using the input files provided by Xcel and then compared the Department's Strategist outputs to Xcel's Strategist outputs as documented in the Excel files provided by the Company. In this case comparing annual total costs from the Department's run to the annual total costs from the Company's run as documented in the Excel spreadsheets yielded the same results, except for rounding differences. Thus, the Department was able to verify the Company's results for each of the Company's 104 markets-off runs.

Third, the Department briefly reviewed Xcel's Excel spreadsheets to determine if they correctly presented Xcel's Strategist's results. To start the Department compared the difference between our Strategist's outputs of Societal Costs and Total Resource Cost[32] to the Externality Cost calculated by Xcel[33] and included in the Company's reported societal costs. The two were the same, which is a step in the right direction.

[32] For Xcel's reference, these are reported in the tab "Proview" in the Excel spreadsheets.
[33] For Xcel's reference, this is calculated in the tab "System Cost" and then carried over to the tab "PVRR Results" in the Excel spreadsheets.

The Department then attempted to compare our Strategist's Total Resource Cost to the same number calculated by the Company. In this case, the Company's calculated costs[34] differed from our Strategist's Total Resource costs.[35] The difference first appears in the year 2027 and appears to be related to the Sherco CC unit that is added in 2027. However, since the difference is the same in each run (is a fixed cost), the error cannot impact the difference between scenarios. Since the goal is to compare the differences between scenarios, the effects due to the Sherco CC unit should have no effect here.

While not a fatal flaw, this error is yet another example of the problems with the Company's process for handling Strategist. The Company fails to design Strategist so that the total cost number reported by Strategist includes all costs, which[36] means that Xcel must recalculate the total cost of a scenario in the Excel spreadsheets. Xcel then creates further, needless complications by discounting the cost numbers to a different year than Strategist does. While the Department understands the value in having Strategist results downloaded into a file accessible to a broader audience, there is no need for creating the potential for additional errors that is present in Xcel's process. All that should be done is to download and present the Strategist results in an easily understood format. Until Xcel designs a process for appropriately running Strategist and downloading the results the Company should expect to continue to have these problems.

In summary, while the Company's Excel spreadsheet for handling Strategist outputs contains an error, in this case the error is not fatal on its own; it merely calls into question Xcel's ability to represent the Strategist results. Considering the issues present (in term of data control) in the Company's response to Department Informal Information Request No. 1 this conclusion is not surprising.

ii. Main Analytical Steps

1. Background

Overall, in economic terms, Xcel's proposed transaction of owning MEC rather than continuing to purchase power from the existing PPAs would increase costs for ratepayers. The proposal would create additional revenue requirements due to the capital costs (the purchase price) incurred by the Company and associated costs of depreciation, overall rate of return and property taxes. Also, there would be revenue requirements due to the variable costs incurred

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[34] For Xcel's reference, these are the categories Fixed O&M / Capacity Payments; Energy Costs / VOM / Fuel; Emission Costs; and DSM (as calculated in the tab "System Cost").
[35] For Xcel's reference, these are reported in the tab "Proview" and the Company's calculated internal costs equals Strategist's Total Resource Costs minus Fixed Charges.
[36] Technically, under Xcel's Strategist inputs the revenue requirements for capital projects (from the CER) are not transferred into the overall system cost numbers.

when MEC generates electricity. Conceptually, for the proposed transaction to be economic, there must be sufficient savings from fixed and variable cost reductions due to the changed ownership to offset the increased revenue requirements due to Company's ownership of MEC.

2. Capacity Spot Market

Regarding fixed costs, the proposed transaction would provide additional accredited capacity to Xcel's system. However, in MISO capacity has little value at this time, particularly in Zone 1 where Minnesota is located. The MISO market prices for capacity have been low for many years and thus is appropriate for acquiring small amounts of capacity for short-term periods. Moreover, there are numerous options for acquiring long-term capacity if and when it is needed in large quantities.

Xcel's Strategist database contains an annual capacity market, similar to MISO's annual Planning Reserve Auction (PRA). Strategist uses Xcel's capacity market and the associated market price to estimate purchases and sales of small amounts of capacity each year. Through this process Strategist attaches a value to the accredited capacity surplus/shortage. In addition, the annual capacity market ensures that scenarios with MEC purchased and those with MEC remaining under a PPA will have equal reliability as both approaches will have the same level of reserves.[37]

The data indicates that Xcel priced capacity market sales and purchases at the cost of a combustion turbine rather than an estimate of the PRA price. Thus, Xcel's price estimate is too high. However, the result on the overall decision to purchase MEC in question will be small due to 1) the relatively low quantities that Xcel allows to be involved, and 2) the fact that in some years Xcel purchases capacity and in other years Xcel sells capacity. With the spot capacity market dismissed as unimportant, in Strategist the main capacity benefit for MEC would be offsetting other long term capacity purchases/builds. The costs avoided by not having to construct other units would be considered by Strategist through the process of selecting the expansion plan.

Figure 1 shows the difference in capacity between a scenario where MEC remains under a PPA and a scenario where MEC is purchased by Xcel.

[37] This fact is true after the first few years when Xcel has more surplus capacity than the market allows to be sold.

FIGURE 1: Capacity Impact of MEC Purchase[38]

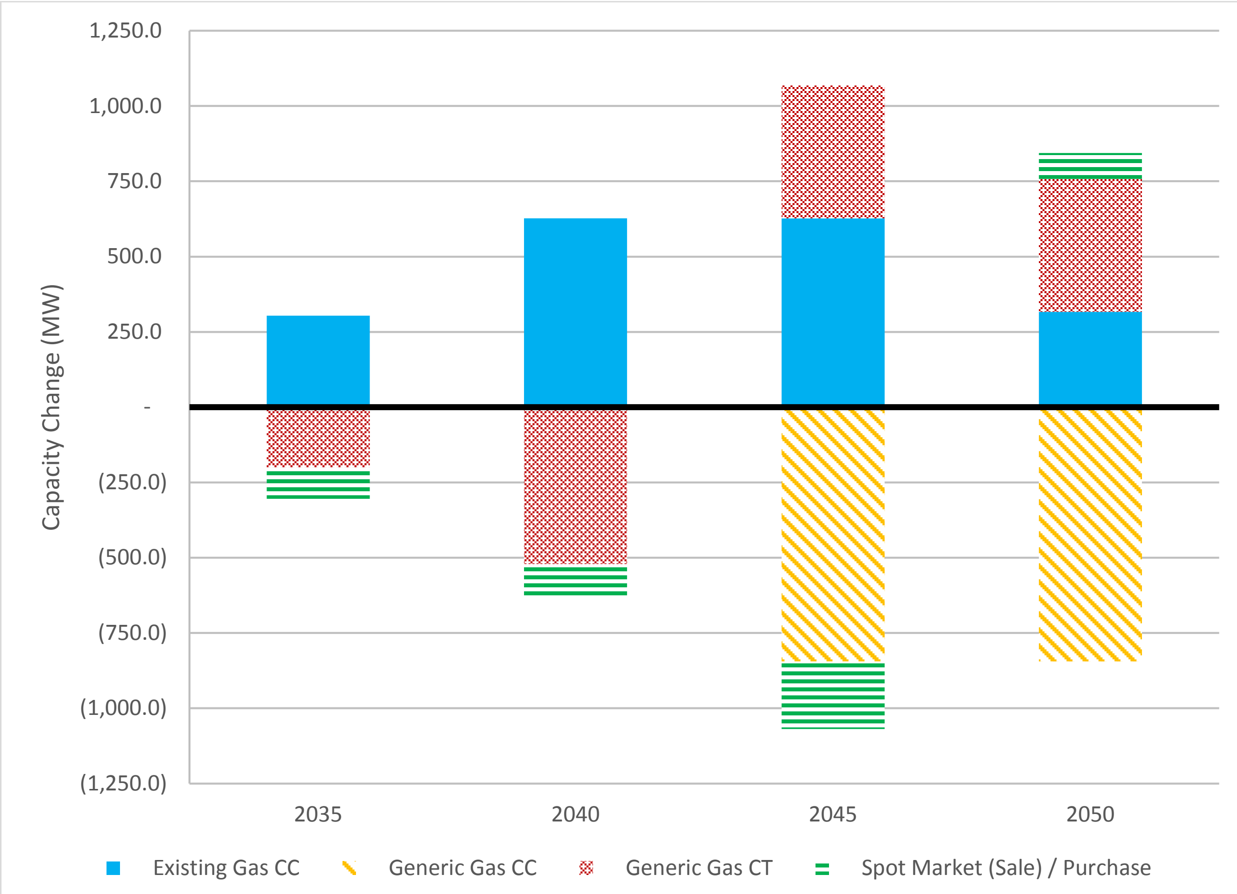

Figure 1 shows new long-term capacity additions and spot market purchases above the zero point and avoided long-term capacity additions and spot market sales below the zero point. Thus, in 2035 and 2040 Xcel's proposed MEC purchase would increase existing CC capacity (MEC would be in Xcel's supply portfolio for more years than under the PPA), while avoiding a small amount of annual capacity market sales, and the acquisition new CT capacity. In 2045 and 2050 the proposed transaction would still increase existing CC capacity (MEC again), require the purchase of more CT capacity, avoid/enable some annual capacity market sales in 2045/2050, and avoid the purchase of a CC unit.

Note that there are no differences in renewable capacity (wind and solar) only because Xcel's standard modeling practice is to lock in the renewable expansion plan. That is, Xcel's modeling prohibited renewable resources from competing with MEC. In reality it is likely that changes in the renewable expansion plan would happen as well. This modeling practice is discussed further below.

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[38] For reference, the scenarios are "MANKATO_OWN_HRE_MIDCO2_FN" and "MANKATO_BASE_HRE_MIDCO2_FN."

The most interesting information shown by Figure 1 is the mismatch in the early years between Xcel's proposal (the CC capacity above the line) and what Strategist would do in absence of the purchase (the peaking capacity below the line). This information indicates that, from a capacity perspective Xcel's proposal would result in higher capacity costs in the early years but, most likely, lower capacity costs in the later years when a new CC unit would be constructed (in the PPA scenario).

In summary, the difference in capacity costs (between MEC PPA and MEC purchased) is unlikely to create substantial savings. Thus, the savings necessary to offset the increased new fixed costs will have to come from reductions in variable costs.

3. MEC Revenue Requirements

The next step in the Department's Strategist review was to ensure that Xcel properly calculated the revenue requirements associated with the capital costs of the MEC purchase in Strategist. The Department compared the revenue requirements for the MEC purchase as calculated by Strategist to the revenue requirements calculated by the Company in the Petition's Attachment G; the two revenue requirement results were the same. Since the Company's MEC project revenue requirements were calculated accurately in Strategist, the next step was to determine if the variable cost savings claimed by the Company (through the Strategist analysis) were reasonable.

4. Renewable Units

Variable cost savings would have to come from changes in how the Company's generating fleet is dispatched. More specifically, the energy drawn from the proposed Xcel-owned MEC must either 1) be cheaper than energy otherwise drawn from the MEC PPA; 2) offset energy from other, higher cost units that were not offset under the MEC PPA; or 3) a combination of the two. The reductions in variable costs must offset the increased capital-related revenue requirements to justify the purchase. Thus, the remainder of the Department's analysis focused on the Company's dispatch of resources because it is dispatch of units that creates variable costs.

The lowest variable costs units are wind and solar, which essentially have zero variable costs. Further, in Strategist wind and solar units are modeled as non-dispatchable. That is, they produce energy according to an hourly production profile provided by the modeler, which has no relation to anything else. Xcel provides each unit its own profile, except for expansion units, which all share a common profile.

The fact that wind and solar operate according to an hourly profile and not variable costs essentially means that these units are considered first in Strategist's dispatch. To spot check these units the Department reviewed the production profiles for the wind and solar generic expansion units. The review considered the distribution of energy production by month, by day of the week, and off-peak versus on-peak. The result of the review was that nothing stood out as unusual.

In this case Xcel followed the Company's standard modeling technique of locking in the renewable expansion plan and not allowing more renewable units to be added; only the natural gas-fueled units are available as expansion options. Thus, Xcel did not allow renewable resources to be considered as an alternative in the expansion plan. The Department did not perform a full analysis of renewable (or any other) alternatives due to time considerations; the Department only evaluated the Company's analysis.

In comments the Department concluded that the high renewable energy scenarios in Xcel's Petition were preferable because they resolved technical issues present in the later years of Xcel's modeling. However, the Department did not address the renewable preference statutes because the analysis did not reach the stage where such considerations could be considered.

Since Xcel's analysis locks in the same renewable expansion plan in all scenarios, it is not possible to determine whether the proposed transaction would result in the same amount or fewer renewable resources being economic and in the public interest. Thus, Xcel did not demonstrate that a renewable energy facility is not in the public interest. That is, Xcel did not make the showing required by Minnesota Statutes § 216B.2422, subd. 4, which states in part:

> The commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest.

5. Nuclear Units

The next units in the dispatch order would be Xcel's existing nuclear units. Figures 2 to 4 below show the capacity annual factors for Xcel's nuclear units divided into three periods, based on history and the results of Xcel's modeling assumptions:

- historical data for 2008 to 2017, drawn from the Company's annual reports to the Department under Minnesota Rules 7610;
- Strategist outputs for 2018 to 2026, before the proposed transaction takes effect; and
- Strategist outputs for 2027 to 2034, after the proposed transaction takes effect through the end of the current license life of the last nuclear unit.[39]

[39] The Strategist outputs used were drawn from a scenario modeling Xcel's system assuming high renewable energy, continuation of MEC under the PPAs, and use of the mid-point of the Commission's externality costs and internal CO_2 cost values. However, the data source is not particularly important since nuclear unit output should not change across scenarios as the units are not dispatchable.

Note that the capacity factors for the last year are excluded from Figures 2 to 4 because Strategist calculates the annual capacity assuming that the unit is available for the full year and the Department determined to not adjust the Strategist outputs.

Figure 2: Monticello Capacity Factors

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TRADE SECRET DATA HAS BEEN EXCISED

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Figure 3: Prairie Island Unit 1 Capacity Factors

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TRADE SECRET DATA HAS BEEN EXCISED

]

Figure 4: Prairie Island Unit 2 Capacity Factors

[

TRADE SECRET DATA HAS BEEN EXCISED

]

Figures 2 to 4 all show that the capacity factors modeled in Strategist for each nuclear unit continually decline from 2023 through the end of the current license life. More importantly, the average capacity factor for Xcel's nuclear fleet from 2027 on (again, excluding the last year) averages only 69.2 percent. By contrast, from 2008 to 2017 Xcel's nuclear units averaged an annual capacity factor of 84.9 percent.[40]

Xcel's assumptions of such ahistorical, low capacity factors post-2026 create a potential bias in Strategist in favor of the proposed transaction because, when a nuclear unit is forced to reduce output, other higher cost units must increase production to replace the lost energy. Then, when the added capacity due to the proposed transaction is modeled, MEC will be able to offset that higher cost generation. Further, Xcel did not allow renewable resources options that

[40] This information is calculated from the Company's annual filings under Minnesota Rules 7610.

might provide that power, so the MEC purchase is one of a few units[41] allowed to offset the lost energy.

6. Coal Units

After the nuclear units, typically the next cheapest units in the dispatch order would be Xcel's coal units. Figures 5 and 6 below show the capacity annual factors for the coal units remaining in 2027 divided into the same three periods as above, based on history and the results of Xcel's modeling assumptions:

- historical data for 2008 to 2017, drawn from the Company's annual reports to the Department under Minnesota Rules 7610;[42]
- Strategist outputs for 2018 to 2026, before the proposed transaction takes effect; and
- Strategist outputs for 2027 to 2034, to be consistent with the nuclear data.[43]

Note that both coal units are assumed to be in-service past 2034 (except for scenarios analyzing early coal retirement) but the time frame for the data presented here is consistent with the nuclear data and provides a reasonable picture of Xcel's modeling.

[41] Depending on circumstances, the Company's coal units and other CC units might also offset the missing energy.
[42] Note that for Sherco 3 in 2008 Xcel reported energy generated but not a capacity factor. Therefore, the Department calculated a capacity factor and used that number in the analysis.
[43] As before, the Strategist outputs used were drawn from a scenario modeling Xcel's system assuming high renewable energy, continuation of MEC under the PPAs, and use of the mid-point of the Commission's externality costs and internal CO_2 cost values.

Figure 5: Allen S. King Capacity Factors

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TRADE SECRET DATA HAS BEEN EXCISED

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Figure 6: Sherburne County Unit 3 Capacity Factors

[

TRADE SECRET DATA HAS BEEN EXCISED]

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Figures 5 and 6 both show that the capacity factors modeled in Strategist for each coal unit are substantially lower in Strategist than in the recent past. More importantly, the average capacity factor for Xcel's coal fleet from 2027 through 2040 (again, excluding the last year of operation) averages only 25.6 percent. By contrast, from 2008 to 2017 Xcel's coal units averaged an annual capacity factor of 60.0 percent.[44] Moreover, the reported historical average capacity factor for the past decade is somewhat low because it includes 3 years (22 months, spanning 2011 to 2013) where Sherburne County Unit 3 had abnormally low capacity factors due to a catastrophic failure and an extended forced outage.

As with the nuclear units, Xcel's assumptions of such ahistorical, low capacity factors post-2026 and failure to consider renewable power as an option create a potential bias in Strategist in favor of the proposed transaction.

[44] Again, this information is calculated from the Company's annual filings under Minnesota Rules 7610.

7. Xcel's Forecast

Above the Department concluded that demand did not play a significant role in the economics of the proposed transaction. Instead, the economics of the proposed transaction are being driven by energy-related considerations. Therefore, as part of the overall analysis, the Department briefly reviewed Xcel's energy forecast net of conservation. This information reflects Xcel's forecast of energy that must be supplied by the Company's resources. The resulting mid-point (base) forecast and the low forecast are shown in Figure 7.

Figure 7: Net Energy Forecast

[

TRADE SRECRET DATA HAS BEEN EXCISED

]

The base forecast net of conservation shows a slow, steady decline in energy use through 2026; the decline averages about -0.2 each year. However, curiously, starting in 2027 when additional capacity and energy under the proposed transaction becomes available, the forecast suddenly changes direction and energy use grows steadily and remarkably; the growth averages about 0.5 percent per year. While the Department did not attempt a full forecast review in the time allowed, the base forecast does not appear to be reasonable and creates yet another bias in Strategist in favor of the proposed transaction. This bias occurs for the same reasons as discussed in the sections on nuclear and coal units. The only difference being instead of supply being decreased demand has been increased. The impact is identical in either case; an assumed greater need for energy. In essence, the more energy that must be supplied, the more value adding an energy-producing resource will have.

Therefore, the Department recommends that, setting aside other objections, the Commission should attach little consideration to contingencies using the base forecast and attach somewhat greater consideration to contingencies using the low forecast, since the low forecast contingency exhibits a more reasonable long term trend. Unfortunately, as will be discussed below, there appear to be significant problems in Xcel's modeling of the low forecast contingency.

8. System CO_2 Emissions

As part of the overall analysis, the Department compared the total CO_2 emissions from Xcel's system over the full period modeled by the Company (2018 to 2057). The emissions were taken from the scenarios including the mid-point of the Commission's externality and CO_2 internal cost values.[45] The analysis concluded that the scenario modeling Xcel's proposed transaction resulted in about 0.45 percent (1.4 million tons) more CO_2 emissions than the scenario where the MEC units remain under the current PPAs. Considering the uncertainty inherent in analysis covering 40 years and the Department's concerns with Xcel's modeling, the Department does not have confidence in Xcel's CO_2 emissions numbers and, in any event, the difference is relatively small. However, these are the results provided by the Company, which do not show its own proposal in a favorable light.

9. Xcel's Cost Analysis

Given the numerous issues the Department discovered in Xcel's modeling inputs, the Department places little value on the results of the Company's modeling. However, if for some reason the Commission concludes that the Company's proposal is reasonable, the results of Xcel's cost analysis as provided in the response to Department Informal Information Request No. 2 are summarized in Attachment 2. Page 1 of Attachment 2 shows the results of Xcel's Strategist analysis assuming that Xcel's coal and nuclear units operate until the current retirement date with the ahistorical capacity factors discussed above. Page 2 of Attachment 2 shows the results of Strategist analysis assuming Xcel's nuclear units operate until their current retirement dates, but the coal units retire early (again using Xcel's unsupported assumptions of capacity factors).

[45] For reference, the scenarios are MANKATO_BASE_HRE_MIDCO2_FN and MANKATO_OWN_HRE_MIDCO2_FN.

In an attempt to provide a more complete record, the Department recalculated Xcel's revenue requirements from the purchase price as documented in the Petition's Attachment G assuming that the $96.194 million acquisition adjustment was removed.[46] Two-thirds of the adjustment was removed from the payment in 2019 labeled "MEC Existing" and one-third from the payment in 2019 labeled "MEC Expansion." This recalculation decreased the present value of the revenue requirements (PVRR) by $105.192 million. The $105.192 million PVRR was calculated in the same manner that Strategist calculates present value and thus can be used to adjust the numbers in Attachment 2 if desired.

Even if Xcel's analysis were valid, the results of the Company's analysis are inadequate to support its own proposal. Referring to Page 1 of Attachment 2 in these comments, under the Department's preferred conditions—column: Mid Externality, Mid CO_2 Costs—the cost difference between the proposed transaction and continued PPAs is within the margin of error if MEC operates to the end of its assumed life (row: MEC Own) or if MEC retires a few years early (row: MEC Own_2050). If MEC retires significantly early (row: MEC Own_2040) then the proposed transaction is not cost effective.

Further, Xcel's modeling shows that any time no or low CO_2 costs are used[47] the proposed transaction is not cost effective. The only time the transaction is clearly cost effective is when both the Commission's high externality and high CO_2 costs are used. Even then, MEC would have to operate to about 2050 to show clear benefits.

Consideration of variations in the demand and energy forecast[48] in Xcel's Strategist inputs appear to reveal a significant problem in how Xcel models use Strategist. The cost differences for the low forecast contingency are significantly different than the cost differences for any other contingency. One potential explanation is that Xcel's modeling practice of locking in units significantly limited the ability of Strategist to adapt to different forecast levels. However, the Department did not attempt to identify the source of the problem due to the limited time available.

Therefore, even if the other issues identified by the Department above are determined to be of no concern, the Department would recommend that the Commission not rely upon the results of Xcel's contingencies that explore forecast variations. Considering the problematic nature of Xcel's base forecast, the inability of the Company to adequately model changes in forecast is an important issue.

Referring to page 2 of Attachment 2, Xcel did not model the recently announced plan to re-license the Monticello unit and operate it for an additional decade as part of the early coal retirement package. As with Xcel's nuclear unit modeling, coal unit modeling, and base

[46] See below for a discussion of the acquisition adjustment.
[47] See columns "Low Externality, Low CO2 Costs" through "High Externality, No CO2 Costs."
[48] See columns "Low Forecast" and "High Forecast."

forecast, this omission would create a bias in Strategist in favor of the proposed transaction. When Monticello is retired earlier than Xcel's current plan to seek an extension of Monticello's license, that earlier retirement causes other, higher cost units to increase production to replace the lost energy. Then, when the added capacity due to the proposed transaction is modeled, MEC is seen as offsetting higher cost generation, particularly since Xcel prohibited renewable resources from providing the energy.

However, ignoring these flaws, including Xcel's failure to allow renewable resources to compete with the MEC purchase, and taking the Company's analysis at face value, if MEC retires significantly early (row: MEC Own_2040), Xcel's own analysis indicates that the proposed transaction would be clearly cost effective only if the Commission's CO_2 cost value is modeled at the mid-point or high levels. When MEC is assumed to operate to 2050 or beyond (row MEC Own_2050 and row MEC Own), Xcel's analysis indicates that the proposed transaction would be cost effective under all contingencies except high natural gas prices.

The importance of using the high end of the Commission's externality and CO_2 cost values highlights the importance of the Company's modeling technique. Again, as discussed above Xcel does not allow Strategist to select additional renewable options. Instead, Strategist is required to follow a particular renewable expansion plan. Therefore, as the Commission's externality and CO_2 cost values increase from none, to low value, to the mid-point, and then to the high value, and given Xcel's assumptions about the low capacity factors of its nuclear facilities, the only option available to Strategist to adapt to the higher costs by reducing emissions is to increase reliance on natural gas combined cycle units such as MEC. Thus, the Company's modeling technique introduces yet another bias in the Strategist analysis towards the proposed transaction.

Finally, while it is not relevant here since such decisions will be made in Xcel's IRP proceeding, Xcel's own analysis under the Department's preferred conditions (column: Mid Externality, Mid CO2 Cost) shows that *early retirement of the coal units is a lower cost option regardless of whether MEC continues under the PPAs or the Commission approves the proposed transaction*.[49]

In other words, Xcel's own analysis shows its proposal is not necessary to shut down the coal units since they should shut down early in any case to reduce costs. Thus, there is no reason to force ratepayers to pay for Xcel's MEC ownership in order to shut down coal facilities early. The Department expects that decisions regarding Xcel's coal facilities will be made in the Company's concurrent IRP.

c. Department's Modeling Conclusions

[49] Compare the total cost listed on page 1 of Attachment 2 to the total cost on page 2 of Attachment 2.

Due to the numerous flaws in Xcel's Strategist inputs and modeling technique, the Department considers all four rounds of the Company's modeling analysis to be of no value. For example, Xcel used unreasonable assumptions to inflate MEC's value artificially, with biases such as:

- Using unrealistically low capacity factors for existing nuclear and coal facilities, thus inappropriately making it appear that Xcel needs more energy resources;
- Forecasting high (ahistorical) demands for energy, again making it appear that Xcel needs more energy resources; and
- Prohibiting renewable resources from competing with the MEC purchase.

Therefore, the Department concludes that Xcel failed to meet its burden to demonstrate that there is a need for additional intermediate capacity beyond that identified in the Company's most recent resource plan.

In addition, by failing to allow renewable resources to compete with the MEC purchase, Xcel did not meet the renewable preference in Minnesota Statutes §216B.2422, subd. 4.

Moreover, even if Xcel's analysis were valid, Xcel's own modeling showed that:

- the MEC purchase is not needed for early coal retirements;
- Xcel's system would emit about 1.4 million tons *more* CO_2 with the purchase than without;
- the MEC purchase is clearly cost effective *only if* MEC is operated far into the future, even beyond 2050; thus
- early retirement of MEC, to meet CO_2 reduction goals for example, would make the MEC purchase an even more costly option for Xcel's ratepayers.

In sum, overall, Xcel failed to demonstrate that its proposal is consistent with the public interest as required by Minnesota Statutes § 216B.50. Therefore, the Department recommends that the Commission reject the Petition.

B. REVIEW OF COST RECOVERY AND ACCOUNTING ISSUES

Overall, the Department concludes that because Xcel has failed to show that MEC I & MEC II are needed for resource planning purposes (as discussed in more detail in the below section) all cost recovery and accounting issues should be denied. However, since the Commission may disagree with the Department, the Department addresses costs recovery and accounting issues in this section.

1. *2019 Revenue Requirement True-Up*

The Department recommended the following on page 6 of our March 5, 2019 Initial Comments regarding Xcel's proposal to charge its ratepayers $10.62 million for 2019 (assuming approval by September 1, 2019) for what Xcel calls "Revenue Requirement Under-Recovery After Purchase." In other words, this surcharge would be a 2019 Revenue Requirement True-Up, in addition to the costs that are built into Xcel's base rates:

> - a true-up or rider recovery of capacity/capital costs and O&M costs of a gas facility is not allowed by Minnesota law;
> - a similar true-up was not allowed for Minnesota Power in Docket Nos. E015/AI-17-568 and E015/RP-15-690;
> - Xcel is subject to a rate case settlement through 2019; and
> - a waiver to allow capacity/capital costs and O&M costs through the FCA is not appropriate since these are not FCA-eligible costs per Minnesota Rule and Xcel will have an opportunity to request cost recovery in its upcoming rate case.
>
> Thus, the Department recommends that the Commission deny Xcel's request for the rate recovery true-up for 2019 revenue requirements.

Xcel provided the following arguments on pages 14-15 of its Reply Comments, to address the Department's recommendation to deny the $10.62 million surcharge in the proposed 2019 Revenue Requirement True-Up:

> While both the rate case paradigm and our settlement generally require the Company to weather changes to our cost of service during the course of our [multi-year rate plan] MYRP and until filing our next rate case, there are exceptions to this general rule. Passage of the [tax cuts and job act] TCJA represents one such exception, and the Commission recently ordered the Company to refund $136 million in 2018 TCJA savings to customers.
>
> We believe our MEC proposal represents another reasonable exception. We did not anticipate Southern deciding to put MEC up for sale when we entered into our MYRP Settlement. We therefore did not factor the costs associated with taking ownership of MEC into any part of our cost of service or the terms of the settlement. When we learned that Southern did intend to sell MEC, we carefully evaluated a potential transaction and concluded that it was likely to result in customers benefits on both a PVRR and PVSC basis, as well as the various other benefits discussed earlier in these

> comments. We therefore believe the transaction is squarely in the public interest and will benefit our customers, stakeholders, and the state.
>
> We are requesting an FCA variance in order to remain financially whole and to not suffer a penalty as a result of bringing this transaction forward for Commission review. The Department's recommendation, if adopted by the Commission, would dissuade the Company (and other utilities) from seeking out or responding to beneficial transactions in between rate cases. We do not think the public interest is best served by limiting our ability to pursue such opportunities in lockstep with our rate case filing schedule, nor is it served by the Company trying to forecast the number and type of such opportunities that might arise for purposes of forecasting a test year. We therefore reaffirm our request for an FCA variance to recover the difference between the 2019 revenue requirement resulting from the transaction and the revenues already in base rates for the capacity portions of the current MEC I and MEC II PPAs.

Xcel has not provided any information that would cause the Department to recommend approval of Xcel's proposed $10.62 million surcharge to its customers for 2019. Utilities are generally not entitled to recover costs outside of a rate case except under extraordinary circumstances and only for costs that are specifically set out in statute.

Further, Xcel did not provide any information to support why capacity/capital costs and O&M costs (i.e. non-fuel costs) should be allowed recovery through the FCA (thereby ignoring Minnesota Rules). Xcel's only comment was that not allowing Xcel to recovery these non-fuel costs through the FCA means they believe they won't remain financially whole. The Department notes that Xcel has not provided information to show that overall – for all costs and revenues (not just costs of MEC I and II), Xcel would not be financially whole for 2019. Finally, the Department opposed a similar proposal by Minnesota Power as discussed in our comments;[50] likewise, the Department opposes Xcel's request.

Finally, the Department notes that Xcel chose to file a multi-year rate case in 2015 and remains subject to the rates and approved settlement in that proceeding. In the Department's view, the settlement would not allow additional recovery of costs for MEC I and II (difference between PPA and Xcel ownership recovery) at least for the remaining months in 2019.

Xcel believes that MEC I and II should be subject to an exception like the TCJA (Tax Cuts and Jobs Act). The Department disagrees, as the TCJA is a factor that affected all utilities, is due to

[50] Department's March 5, 2019 Comments, pages 5-6.

circumstances that are clearly beyond utilities' control and is not simply a matter of moving from charging ratepayers for the costs of power in a PPA to charging them for costs of an optional ownership of a gas plant. That is, the purchase of MEC I and II is at the discretion of the Company.

Thus, the Department continues to recommend that the Commission deny Xcel's request for the rate recovery true-up for 2019 revenue requirements.

2. Transaction Costs

The Department recommended the following on page 10 of our March 5, 2019 Initial Comments regarding Xcel's request to charge its ratepayers $450,000 in Transaction Costs:

> - Xcel was unable to show these types of transaction costs were not already included in base rates;
> - the Commission's January 23, 2018 decision in the Benson docket denied recovery of legal costs in addition to the amounts charged to ratepayers in 2017 and 2018 base rates; and
> - Xcel's five-year hold-harmless commitment for wholesale customers should also apply to the Company's Minnesota retail customers.
>
> Thus, the Department recommends that the Commission deny cost recovery from retail ratepayers for the $450,000 in transaction costs.

Xcel provided the following arguments on page 15 of its Reply Comments, to address the Department's recommendation regarding the Transaction Costs:

> Finally, the Department has recommended that the Commission disallow recovery of our transaction costs, which amount to $450,000. Again, we believe this recommendation serves only to penalize the Company for having brought this transaction forward and to potentially dissuade utilities from seeking out opportunities to benefit customers in between rate cases.
>
> The budget for our 2016 test year in our rate case was developed in mid-2015—well before we commenced discussion regarding the acquisition of MEC. We therefore did not account for the transaction or the associated legal fees when developing the 2016 test-year budget. Moreover, our rate case test-year budget included a total of $3,985,759.86 in legal fees and, of that total,

> only $5,000 was budgeted for outside legal services for the acquisition of assets like MEC.
>
> Because the transaction costs for the MEC acquisition were not factored into our base rates, we believe it is reasonable and appropriate for the Company to request and recover the costs that are necessary to bring this transaction forward for Commission approval. Again, we believe the Department's recommendation would serve to dissuade the Company and other utilities from pursuing beneficial transaction in between rate cases when the costs of those transactions have not already been factored in the Company's most recent test year.

As discussed above, utilities are generally not entitled to recover costs outside of a rate case except under extraordinary circumstances and only for costs that are specifically set out in statute. As noted in our initial comments, the standard for review is for Xcel to show that a representative amount of legal costs are not already being charged to customers in Xcel's base rates, which Xcel has not shown.

Xcel attempted to say that only $5,000 of their $4 million legal budget labeled "Other" relates to the current MEC I and II transaction.[51] However, such an assertion is without a basis; rates are set based on a typical (or representative) level of annual expenses and not on the basis of costs for any specific project. Utilities get to charge customers for the representative expenses, regardless of whether or not the utility prudently incurs such costs in any particular year. In exchange, utilities do not later get to surcharge customers for expenses of any specific project. Such an approach would unreasonably double-charge ratepayers.

The Department also noted in its Initial Comments that, in the Commission's January 23, 2018 *Order Approving Petitions, Approving Cost Recovery Proposal, and Granting Variances*, regarding the termination of Xcel's power purchase agreement with Benson Power, LLC (Docket No. E002/M-17-530), the Commission did not allow recovery of legal expenses since they were already built into base rates. Xcel did not address this concern in its Reply Comments.

In our initial comments the Department noted that Xcel committed to the Federal Energy Regulatory Commission (FERC) to hold wholesale customers harmless for five years due to the proposed acquisition of MEC I and II.[52] The Department recommended that the five-year hold-

[51] In addition to the $4 million that Xcel charges to ratepayers for legal costs, Xcel also charges nearly $3.5 million for Administrative and General (A&G) "outside services." Xcel did not address why it did not consider any of the $3.362 million in generic "A&G Outside Services," which was not tied a specific transaction, to apply to the proposed project.

[52] Department's March 5, 2019 Comments, pages 9-10.

harmless commitment also apply to the Company's Minnesota retail customers. The Company did not address this concern in their Reply Comments.

Thus, the Department recommends that the Commission deny cost recovery from retail ratepayers for the $450,000 in transaction costs.

3. *Net Book Value for MEC I and II*

The Department recommended the following on page 11 of our March 5, 2019 Initial Comments regarding Net Book Value for MEC I and II:

> The Department is concerned that MEC I was already placed in service and continues to operate under its PPA to Xcel, so **[TRADE SECRET DATA HAS BEEN EXCISED]** Thus, the Department recommends that the **[TRADE SECRET DATA HAS BEEN EXCISED]** should be recorded and reflected in the NBV, thereby reducing Xcel's estimated $541 million NBV by the same amount.
>
> Additionally, the Department notes that Xcel should be required to record and reflect additional depreciation expense of approximately **[TRADE SECRET DATA HAS BEEN EXCISED]** for the period between the June 1, 2019 purchase date and the inclusion of MEC in base rates, which is likely to be as of January 1, 2020, thereby reducing Xcel's estimated $541 million NBV by the same amount.

Xcel provided the following arguments on page 12 in footnote 5 of its Reply Comments, to address the Department's recommendation regarding the Net Book Value for MEC I and II:

> FERC rules also require the Company to recognize acquisition date accumulated depreciation of MEC consistent with Southern Power's financial statement. And since the transaction was executed, Southern Power—in conformity with GAAP—has classified the plant as "held for sale" and ceased depreciation since that date. We believe this accounting treatment is appropriate and therefore have reflected the same in our calculations of net plant, in conformity with FERC rules.

The Department notes that Xcel failed to address the Department's concern of how MEC I, a plant that is currently in-service and operating under an existing and continuing PPA that continues to charge Xcel's ratepayers for depreciation expense, can be reclassified *by Xcel for proposed ratemaking purposes* as "plant held for sale" and therefore cease recording depreciation while continuing to operate at the same time. The Department does not agree that this approach is in conformity with GAAP (Generally Accepted Accounting Principles) and Xcel has not provided any citation to support the Company's incorrect conclusion. In the Department's view, this proposal looks like an attempt to overstate the net book value of the MEC facilities and double-charge ratepayers for the same costs.

The Department does not see how Xcel and Southern Company can arbitrarily stop recording depreciation expense for the MEC asset that is clearly in use and being used to provide service under an existing PPA.

As a result, the Department continues to recommend the net book value of the MEC facilities be adjusted as noted in our Initial Comments:

> The Department is concerned that MEC I was already placed in service and continues to operate under its PPA to Xcel, so **[TRADE SECRET DATA HAS BEEN EXCISED]** Thus, the Department recommends that the **[TRADE SECRET DATA HAS BEEN EXCISED]** should be recorded and reflected in the NBV, thereby reducing Xcel's estimated $541 million NBV by the same amount.
>
> Additionally, the Department notes that Xcel should be required to record and reflect additional depreciation expense of approximately **[TRADE SECRET DATA HAS BEEN EXCISED]** for the period between the June 1, 2019 purchase date and the inclusion of MEC in base rates, which is likely to be as of January 1, 2020, thereby reducing Xcel's estimated $541 million NBV by the same amount.

4. *Acquisition Adjustment*

The Department recommended the following on pages 14-15 of our March 5, 2019 Initial Comments regarding the Acquisition Adjustment:

> Based on our review to date, the Department recommends that the $96.194 million acquisition adjustment be denied. The Department provides the following to support this recommendation:
>
> - MEC is an asset that is already devoted to public service and is used and useful under an existing PPA;
> - For purposes of FERC and Minnesota ratemaking – use of the net book value is appropriate for setting rates;
> - Xcel did not do a competitive bid process; and

> - Allowing approval of an acquisition adjustment must meet a heavy burden to justify cost recovery – which we don't believe Xcel has fully met as further discussed in the next section – Comparison of PPA and Revenue Requirement Ownership.

Xcel provided the following arguments on pages 12-14 of its Reply Comments, to address the Department's recommendation regarding the Acquisition Adjustment:

- First, Xcel argued that the Company cannot move forward with the transaction if $96 million of the proposed purchase price (acquisition adjustment) is deemed unrecoverable. Xcel states that "the transaction would not be financially viable, and we would need to exercise our right to exit the agreement under to the conditions precedent for regulatory approvals."

- Second, Xcel disagreed with the Department's recommendation on the acquisition adjustment for what the Company calls policy reasons. Xcel states:

  > While the Department is correct to point out that FERC accounting rules require the Company to record the plant's net book value separately from the remainder of the purchase price (*i.e.,* the "acquisition adjustment"), those rules do not preclude the Company from recovering the total amount of its investment. Xcel notes that market conditions change over time and fuel and energy prices shift with changing market conditions and so too does the value of generating plants like MEC. This is particularly true when large systemic changes in market conditions occur, such as the passage of the TCJA in 2018, which effectively increased the value of plants that had long-term PPAs in place with pricing that was based on a 35% corporate tax environment. There is little reason, then, to assume that fair market value for a plant should be tied to net book value, and little reason to disincentivize the Company from seeking out beneficial transactions simply because the asset in question is already in service. The Company notes that the net book value reflects the original cost to construct a plant—not what a plant might be valued at in today's market.[53]

- Third, Xcel stated that "[i]f the Commission determines that the transaction is in the public interest … the ultimate rates that incorporate the purchase price must, by definition, be just and reasonable." Thus, Xcel states: "the Commission

[53] Xcel's Reply Comments, page 12.

> should focus its analysis on whether the transaction as a whole is in the public interest and not on an adjustment that prevents the Company from moving forward with the purchase."[54]

The Department responds as follows. First, Xcel's statement in its Reply Comments that the purchase of MEC I and II is not financially viable if the $96 million acquisition is not approved is actually a helpful clarification. It means that, without the full $96 million acquisition adjustment (no middle ground), no purchase will occur. As described in depth above, despite having four opportunities to show that its proposal was reasonable, Xcel failed to do so. Thus, based on the facts in this case, Xcel did not meet its "heavy" burden required to show clear benefits that exceed the $96 million acquisition adjustment.

Second, even if Xcel had met that burden, as discussed in the Department's Initial Comments, Xcel was unable to justify charging ratepayers for the acquisition adjustment.[55]

Third, Xcel seems to believe that the standard for rate recovery for MEC I and II is fair market value; the Department disagrees. The FERC Uniform System of Accounts as adopted by Minnesota and Minnesota ratemaking operate under a system of cost-based regulated rates (not market-based rates). In this case MEC I and II are cost-based assets that were providing energy/capacity under a PPA agreement and were generation plants already devoted to public service.

Moreover, Xcel's response noted above identifies what Xcel is attempting to do: retain for its shareholders the value of the reduction in federal income taxes from 35 percent to 21 percent. This objective is reflected in Xcel's reference to "the passage of the TCJA in 2018, which effectively increased the value of plants that had long-term PPAs in place with pricing that was based on a 35% corporate tax environment." Given the facts in this case, Xcel has not demonstrated that it is reasonable to charge its ratepayers for the high costs of the $96 million acquisition adjustment, for the following reasons. Xcel:

- did not support need for resource planning purposes;
- did not provide any relevant cases that support rate recovery of an acquisition adjustment;
- did not perform a competitive bid to support the market price; and
- did not provide a clear showing of benefits that exceed additional costs and risk of moving from a PPA to an ownership method (as discussed in the next section).

[54] *Id*. at 14.
[55] A full discussion can be found in the Department's March 5, 2019 comments on pages 11-14.

In addition, as discussed above, Xcel's ownership proposal would increase its customers' rates almost immediately due to its $10.62 million "true-up" proposal, $450,000 for "transaction costs" and Xcel would charge its ratepayers twice for the same depreciation costs for 2019.

Thus, based on our review to date, even if the Commission approves Xcel's proposal despite the facts in this proceeding, the Department recommends that the Commission deny the $96.194 million Acquisition Adjustment. The Department provides the following to support this recommendation:

- MEC is an asset that is already devoted to public service and is used and useful under an existing PPA;
- For purposes of FERC and Minnesota ratemaking – use of the net book value is appropriate for setting rates;
- Allowing approval of an acquisition adjustment must meet a heavy burden to justify cost recovery – which Xcel did not fully meet as further discussed in the next section – Comparison of PPA and Revenue Requirement Ownership.
- Xcel has not shown a need for resource planning purposes;
- Xcel did not provide any relevant cases to support rate recovery of an acquisition adjustment; and
- Xcel did not use a competitive bid process to support its market price.

5. *Comparison of Purchase Power Agreement & Revenue Requirement Ownership*

The Department recommended the following on page 17 of our March 5, 2019 Initial Comments regarding the Comparison of Purchase Power Agreement and Revenue Requirement Ownership:

> The Department concludes that the present value revenue requirement amounts assuming ownership versus continuing with the PPAs over the life of the MEC plants are similar.
>
> However, there are some significant cost risks that would be shifted to Xcel and its ratepayers should the plant purchase be approved, including:
>
> - decommissioning would become the responsibility of Xcel and its ratepayers;
> - plant outages and equipment failures would become the responsibility of Xcel and its ratepayers;

> - risk of higher property taxes would be shifted to Xcel and its ratepayers; and
> - risk of higher O&M expenses would be shifted to Xcel and its ratepayers.
>
> As a result, the Department does not believe Xcel has shown clear benefits of ownership.

Xcel provided the following arguments on pages 9-10 of its Reply Comments, to address the Department's recommendation regarding the Comparison of Purchase Power Agreement and Revenue Requirement Ownership:

- First, Xcel disagreed that the benefits associated with ownership versus the PPAs are similar. Xcel stated that its updated Strategist modeling demonstrates that Xcel expects customers to enjoy well more than $100 million in benefits on a present value of revenue requirements basis.

- Second, Xcel stated its belief that:

> …two of the identified risks—related to stranded assets and property tax expenses—have already been sufficiently mitigated. With respect to property taxes, we have undertaken substantial efforts to ensure that they will qualify for the same property tax exemptions that applied to Southern's ownership of MEC. Moreover, we have experience applying for, and receiving, the same exemption at other sites. We therefore do not see any significant risk associated with our ability to receive favorable property tax treatment.
>
> With respect to the risk of stranded assets, Xcel believes our updated Strategist modeling should address many of these concerns by demonstrating that the transaction is cost effective even if we retire the plants earlier than stated in our initial Petition.[56]

- Third, with respect to the remaining two risks—operating and decommissioning costs, Xcel stated its belief that the estimates of O&M and decommissioning costs used in their modeling "are reasonable and in line with both industry standards and the Company's experience in operating similar combined cycle plants." Specifically, Xcel stated that:

[56] Xcel's reply comments, page 10.

> …the Company worked to ensure that estimates of O&M and ongoing capital at the facility were in line with our experience operating the High Bridge and Riverside plants on our system. We also validated fixed costs (plant gas, electricity, fixed labor, tax, insurance, etc.) and variable costs (chemicals, consumables, water) using diligence information provided by Southern Power related to its ownership of Mankato. In short, we believe our cost projections are consistent not only with our own experience in the industry and operating similar plants but also with Southern Power's own experience in operating MEC itself. [57]

The Department responds as follows. Regarding Xcel's first argument, as discussed at length above, Xcel's modeling is inadequate to demonstrate that the MEC purchase is in the public interest, for either Xcel's customers or the public as a whole.

Regarding Xcel's second argument, as noted on pages 16-17 of our initial comments regarding the comparison of ownership compared to PPA method that Xcel's proposal would shift risks to Xcel's customers, and Xcel's reply comments do not address that risk adequately. Xcel's statements about its beliefs that they "do not see any significant risk" is certainly not the same as Xcel committing to charge its ratepayers no more than is charged under the PPA. In fact, Xcel proposes to charge ratepayers more than the amounts under the PPA, as discussed above.

Moreover, Xcel's statement that "the transaction is cost effective even if we retire the plants earlier" is not valid, as discussed above. In addition, there are material concerns regarding the potential of stranded assets. As noted in Xcel's response to Office of Attorney General – Residential Utility and Antitrust Division, Information Request No. 103, the net book value of the MEC I and II plants as of the end of 2040 is **[TRADE SECRET DATA HAS BEEN EXCISED]**. The Department notes this is a material amount of plant that could result in stranded costs for Xcel and its ratepayers, if MEC I and II are retired early.

As to Xcel's third argument, while we appreciate Xcel indicating that their O&M costs and decommissioning costs are consistent with industry standards, Xcel's recent rate cases, depreciation studies and decommission studies have shown material cost increases to both Xcel's O&M and decommissioning costs.[58] Thus, pointing to industry standards is not helpful, when such costs could be avoided simply by continuing with the existing PPAs.

Additionally, as shown on page 16 of the Department's initial comments, Xcel's table called "Incremental Revenue Requirements Impact High Renewables" estimates variable operating and maintenance (VOM) *savings* of $32 million, despite the upward trend in Xcel's VOM

---

[57] *Id*.
[58] For example, the Department notes that Xcel asked for a 3.85 percent increase in Energy Supply Operating and Maintenance Expenses, however, the Department recommended a 2.5 percent increase (see Campbell Direct pages 35 to 39 in Docket No. E002/GR15-826) that was included in the Settlement revenue requirements as shown on DLV-9 second errata.

costs. Xcel hasn't shown how such level of savings in VOM expense would be gained by having Xcel operate MEC I and II rather than Southern Company.

Finally, the Department notes that the return on equity Xcel assumes for the MEC purchase, as shown in Xcel's Initial Petition Attachment G, Revenue Requirements is excessive. In addition, if Xcel owns MEC, the ROE would be subject to change over time, exposing ratepayers to risks of paying higher returns on the same asset.

Overall, for all of these reasons, the Department concludes that a PPA methodology better protects ratepayers from risks by keeping costs fixed during the contract period and by not requiring ratepayers to pay for stranded costs of the plant that occur after the contract period of the PPA, decommissioning costs, plant outages or failures, higher O&M expenses or higher returns on equity for the same asset. Thus, in addition to the Strategist analysis above, the Department does not recommend approval of the purchase of MEC I and II; instead, the existing PPAs should remain in place.

C. RESPONSE TO COMMISSION NOTICE

The Notice indicates that the issue at hand is "Should the Commission approve the purchase of the Mankato Energy Center and approve transfer of its site permit?" Based upon the analysis provided above, the Department recommends that the Commission not approve Xcel's proposed purchase of MEC. As noted elsewhere, these comments do not address the site permit transfer request.

III. DEPARTMENT RECOMMENDATION

As indicated in the Department's comments, the Department recommends that the Commission approve a variance to Minnesota Rules 7825.1800, subp. B to allow Xcel not to provide the information set forth in Minnesota Rules 7825.1400, items (A) through (J).

The Department recommends that the Commission reject the Company's requests to approve the acquisition of Southern's MEC I and MEC II property, under Minnesota Statutes § 216B.50, as Xcel has not shown its proposal to be in the public interest and failed to demonstrate that a renewable energy facility is not in the public interest.

Specifically, as described above, the numerous flaws in Xcel's Strategist inputs and modeling technique render all four rounds of the Company's analysis to be of no **value**. For example, Xcel used unreasonable assumptions to inflate MEC's value artificially, with biases such as:

- Using unrealistically low capacity factors for existing nuclear and coal facilities, thus inappropriately making it appear that Xcel needs more energy resources;
- Forecasting high (ahistorical) demands for energy, again making it appear that Xcel needs more energy resources; and
- Prohibiting renewable resources from competing with the MEC purchase.

Therefore, Xcel failed to meet its burden to demonstrate that there is a need for additional intermediate capacity beyond that identified in the Company's most recent resource plan.

In addition, by failing to allow renewable resources to compete with the MEC purchase, Xcel did not meet the renewable preference in Minnesota Statutes §216B.2422, subd. 4.

Moreover, even if Xcel's analysis were valid, Xcel's own modeling showed that:

- the MEC purchase is not needed for future early coal retirements;
- Xcel's system would emit about 1.4 million tons more CO_2 with the purchase than without;
- the MEC purchase is clearly cost effective *only if* MEC is operated far into the future, even beyond 2050; thus
- early retirement of MEC, to meet CO_2 reduction goals for example, would make the MEC purchase an even more costly option for Xcel's ratepayers.

Thus, overall, Xcel failed to demonstrate that the proposed action is consistent with the public interest as required by Minnesota Statutes § 216B.50.

In addition, a PPA methodology better protects ratepayers from cost increases by keeping costs fixed during the contract period and not requiring ratepayers to pay for stranded costs of the plant that occur after the contract period of the PPA. Thus, the Department does not recommend approval of the purchase of MEC I and II.

Thus, overall, Xcel has not shown need or any net benefits to ratepayers for Xcel's proposed MEC purchase. However, if the Commission decides that the MEC purchase may nonetheless be in the public interest, the following conditions could at least improve Xcel's proposal:

- **Approve only up to 50% or $48.087 million of Xcel's proposed $96.194 million acquisition adjustment** – while there are concerns about allowing any recovery of an acquisition adjustment, reducing this price premium may result in overall net benefits for ratepayers.[59] Reducing the price premium would also significantly reduce possible stranded costs if there is an early 2040 retirement.

  Based on the assessment of the acquisition adjustment in our initial comments, the Department notes the following regarding the amount of the price premium (up to 50%) that the Commission may wish to allow Xcel to charge to its ratepayers:

[59] Due to abnormalities in Xcel's modeling, the Department cannot confirm that there would be net benefits; however, it is more likely that there would be net benefits.

- MEC is an asset that is already devoted to public service and is used and useful under an existing PPA; thus, requiring Xcel's ratepayers to pay more for an asset that already serves them is difficult to support, unless there are benefits of the acquisition that are commensurate with the price premium,
- For purposes of FERC and Minnesota ratemaking – use of the net book value is appropriate for setting rates;
- Xcel did not use a competitive bid process; and
- Allowing approval of an acquisition adjustment must meet a heavy burden to justify cost recovery. While the Department cannot confirm that Xcel has met this burden, if the Commission determines that Xcel has made such a showing, the Commission may wish to allow Xcel to recover up to 50% of Xcel's proposed acquisition adjustment.

- **Disallow recovery of the transaction costs of $450,000** which would reduce overall costs to ratepayers. The Department noted in our comments the following reasons for why the transaction costs should be denied:

    - Xcel was unable to show that these types of transaction costs were not already included in base rates;
    - The Commission's January 23, 2018 decision in the Benson docket denied recovery of legal costs in addition to the amounts charged to ratepayers in 2017 and 2018 base rates; and
    - Xcel's five-year hold-harmless commitment for wholesale customers should also apply to the Company's Minnesota retail customers.

- **Reduce net book value of $541 million by a total of approximately $13 million to reflect unrecorded depreciation** which would reduce costs to ratepayers. The Department noted the following in our comments for why $13 million in unrecorded depreciation should be used to reduce the $541 million net book value:

    - The Department is concerned that MEC I was already placed in service and continues to operate under its PPA to Xcel, so **[TRADE SECRET DATA HAS BEEN EXCISED]** Thus, the Department recommends that the **[TRADE SECRET DATA HAS BEEN EXCISED]** should be recorded and reflected in the NBV, thereby reducing Xcel's estimated $541 million NBV by the same amount.
    - Additionally, the Department notes that Xcel should be required to record and reflect additional depreciation expense of approximately **[TRADE SECRET DATA HAS BEEN EXCISED]** for the

period between the June 1, 2019 purchase date and the inclusion of MEC in base rates, which is likely to be as of January 1, 2020, thereby reducing Xcel's estimated $541 million NBV by the same amount.

- **Deny Xcel's proposed 2019 revenue requirement true-up of $10.62 million** (assumes ownership date by September 1, 2019)[60] for what Xcel calls "Revenue Requirement Under-Recovery After Purchase." This surcharge would be a 2019 Revenue Requirement True-Up (difference between PPA costs built into Xcel's base rates and Xcel's Ownership of MEC). The Department in its comments noted the following concerns:
    - A true-up or rider recovery of capacity/capital costs and O&M costs of a gas facility is not allowed by Minnesota law;
    - A similar true-up was not allowed for Minnesota Power in Docket Nos. E015/AI-17-568 and E015/RP-15-690;
    - Xcel is subject to a rate case settlement through 2019; and
    - A waiver to allow capacity/capital costs and O&M costs through the FCA is not appropriate since these costs are not eligible to be recovered under the fuel clause adjustment per Minnesota Rule and Xcel will have an opportunity to request cost recovery in its upcoming rate case.

- **Cap Xcel's operating and maintenance expenses and capital costs** included in their cost and benefits model (Attachment G of Xcel's Petition). This requirement would reduce some of the costs risks for ratepayers when moving from PPA to Xcel ownership of MEC. For example, Xcel would not be allowed to charge ratepayers any higher costs for decommissioning, higher operation or maintenance expenses, plant outages, equipment failures, etc.

- **Prohibit Xcel from charging its ratepayers for any stranded costs** due to early retirement, unless such retirement before the end of the facility's physical life is explicitly necessary "to comply with a specific state or federal energy statute or policy" as allowed in Minn. Stat. §216B.16, subd. 6.

/ar n

[60] See Xcel's Initial Petition on Attachment H.

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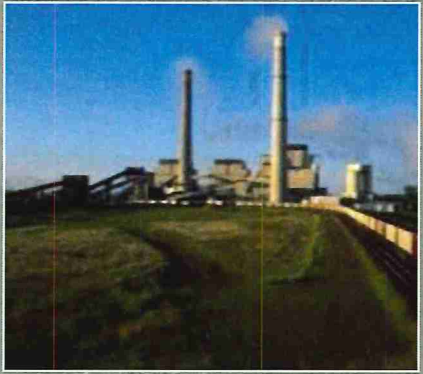
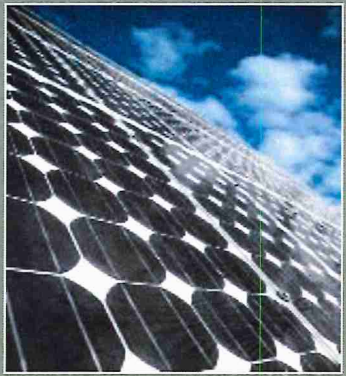
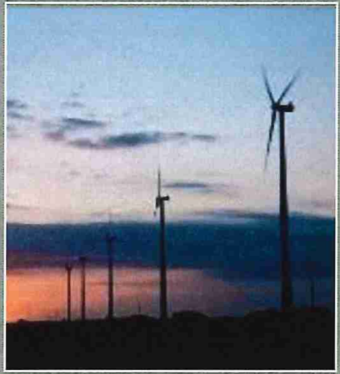
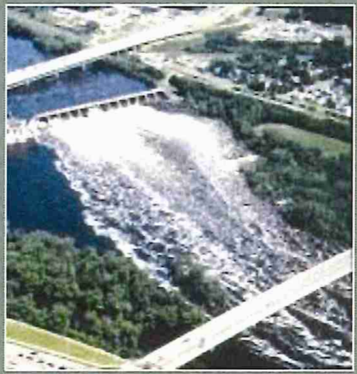






2015 Upper Midwest Resource Plan Stakeholder Workshop Strategist Modeling

April 8, 2015
Minnesota Public Utilities Commission
Small Hearing Room

How is Strategist Used?

Outputs wide array of data for each simulation:

- Unit / transaction costs & generation data
- Environmental performance
- Expansion plan costs

Annual total costs are often converted to single amount using Net Present Value function (at utility discount rate)

Used for decision SUPPORT, not decision making

Just one part of a comprehensive analysis including qualitative and quantitative factors

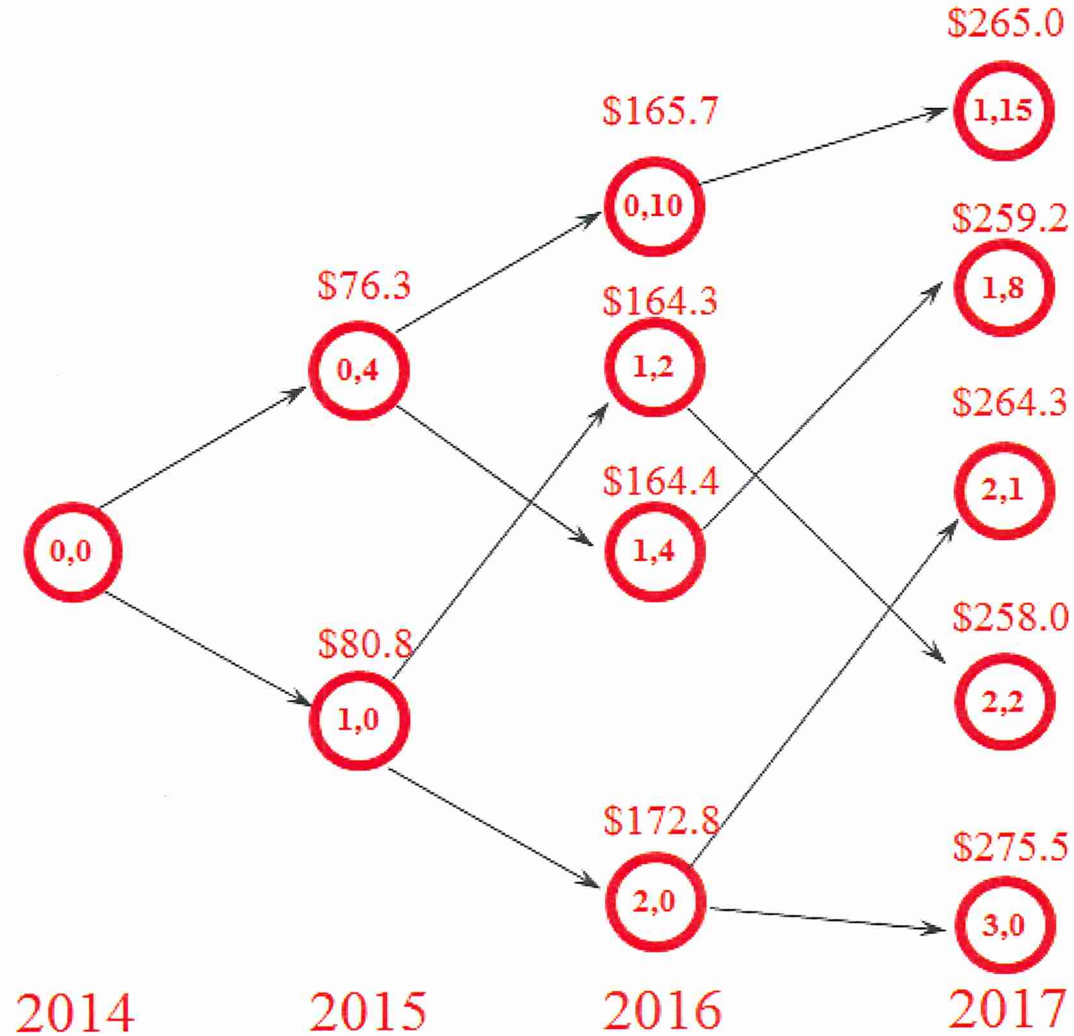
Expansion Plan Method

Notation for new units installed:

x,y

x = Number of 800 MW Combined Cycle Units

y = Number of 100 MW Gas Combustion Turbines



*All price references are hypothetical and used only as an example

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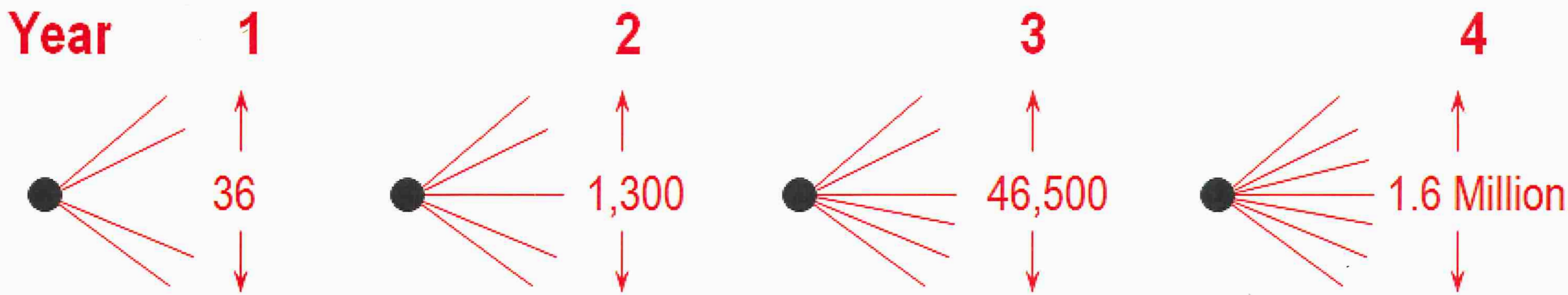
Need to Limit Scope

2 supply alternatives - maximum of 5 per year

Possible Combinations



- Planning horizon = 40 years
- Truncates at 2,500 saved states per year (removes highest costs to-date)
- Must limit options to constrain problem

Strategist Cost Results (Present Value, $,000)

Input	High Externality, High CO2 Costs	Mid Externality, Mid CO2 Costs	Low Externality, Low CO2 Costs	No Externality, No CO2 Costs	PVRR	Low Externality, No CO2 Costs	High Externality, No CO2 Costs	Low Natural Gas Prices	High Natural Gas Prices	Low Forecast	High Forecast	Low MEC Costs	High MEC Costs
Externality Costs?	High	Mid	Low	No	No	Low	High	High	High	High	High	High	High
CO2 Internal Cost?	High	Mid	Low	No	No	No	No	High	High	High	High	High	High
Spot Capacity Priced?	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Mankato Base	$ 53,801,808	$ 51,247,213	$ 48,423,382	$ 46,996,874	$ 47,314,665	$ 49,592,148	$ 57,971,701	$ 52,600,536	$ 55,928,575	$ 52,609,205	$ 57,197,605	$ 53,801,808	$ 53,801,808
Mankato Own	$ 53,709,552	$ 51,227,847	$ 48,449,010	$ 47,089,451	$ 47,414,415	$ 49,678,649	$ 58,044,565	$ 52,489,045	$ 55,943,396	$ 51,880,082	$ 57,021,153	$ 53,674,029	$ 53,742,372
Mankato Own_2040	$ 53,824,175	$ 51,301,166	$ 48,634,421	$ 47,316,474	$ 47,646,307	$ 49,873,046	$ 58,132,468	$ 52,685,301	$ 55,924,462	$ 52,274,007	$ 57,170,902	$ 53,840,668	$ 53,908,860
Mankato Own_2050	$ 53,704,034	$ 51,235,735	$ 48,480,581	$ 47,124,613	$ 47,456,072	$ 49,695,232	$ 58,001,063	$ 52,512,058	$ 55,857,063	$ 51,895,780	$ 57,044,834	$ 53,680,502	$ 53,748,825
Deltas													
Mankato Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mankato Own	$ (92,256)	$ (19,367)	$ 25,628	$ 92,577	$ 99,749	$ 86,501	$ 72,864	$ (111,490)	$ 14,821	$ (729,123)	$ (176,452)	$ (127,779)	$ (59,436)
Mankato Own_2040	$ 22,367	$ 53,953	$ 211,039	$ 319,600	$ 331,642	$ 280,898	$ 160,767	$ 84,765	$ (4,113)	$ (335,198)	$ (26,702)	$ 38,860	$ 107,053
Mankato Own_2050	$ (97,773)	$ (11,478)	$ 57,199	$ 127,739	$ 141,407	$ 103,083	$ 29,362	$ (88,478)	$ (71,512)	$ (713,425)	$ (152,771)	$ (121,305)	$ (52,982)

Scenario Definitions

All Scenarios	Monticello retires in 2030, Prairie Island 1 retires in 2033, Prairie Island 2 retires in 2034, A.S. King retires in 2037, and Sherco 3 retires in 2040.
Mankato Base	MEC remains under the PPAs; MEC I PPA expires in 2026, MEC II PPA expires in 2039.
Mankato Own	MEC is purchased by Xcel and operates as 2x1 into 2046 and as a 1x1 into 2054.
Mankato Own_2040	MEC is purchased by Xcel and operates as 2x1 through 2040.
Mankato Own_2050	MEC is purchased by Xcel and operates as 2x1 into 2046 and as a 1x1 through 2050.

Result Definition

Xcel purchase decreases costs	$ (100,000)
Xcel purchase increases costs	$ 100,000
Result within a margin of error (± 0.05%)	$ -

Strategist Cost Results (Present Value, $,000)

Input	High Externality, High CO2 Costs	Mid Externality, Mid CO2 Costs	Low Externality, Low CO2 Costs	No Externality, No CO2 Costs	PVRR	Low Externality, No CO2 Costs	High Externality, No CO2 Costs	Low Natural Gas Prices	High Natural Gas Prices	Low Forecast	High Forecast	Low MEC Costs	High MEC Costs
Externality Costs?	High	Mid	Low	No	No	Low	High	High	High	High	High	High	High
CO2 Internal Cost?	High	Mid	Low	No	No	No	No	High	High	High	High	High	High
Spot Capacity Priced?	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Mankato Base_EC	$ 53,539,669	$ 51,123,411	$ 48,582,163	$ 47,204,157	$ 47,503,755	$ 49,475,388	$ 56,953,282	$ 52,286,670	$ 55,737,062	$ 52,832,803	$ 57,010,935	$ 53,539,669	$ 53,539,669
Mankato Own_EC	$ 53,323,750	$ 50,912,402	$ 48,398,769	$ 47,011,267	$ 47,322,760	$ 49,310,174	$ 56,882,512	$ 52,045,950	$ 55,791,256	$ 52,215,930	$ 56,816,969	$ 53,288,213	$ 53,356,568
Mankato Own_EC2040	$ 53,477,622	$ 51,076,364	$ 48,599,649	$ 47,245,339	$ 47,549,444	$ 49,513,499	$ 56,985,411	$ 52,264,290	$ 55,794,134	$ 52,609,855	$ 56,965,615	$ 53,494,102	$ 53,562,306
Mankato Own_EC2050	$ 53,355,292	$ 50,941,165	$ 48,424,145	$ 47,036,401	$ 47,340,654	$ 49,338,406	$ 56,920,542	$ 52,075,228	$ 55,838,244	$ 52,231,628	$ 56,840,650	$ 53,331,745	$ 53,400,081
Deltas													
Mankato Base_EC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mankato Own_EC	$ (215,920)	$ (211,009)	$ (183,394)	$ (192,889)	$ (180,995)	$ (165,214)	$ (70,770)	$ (240,720)	$ 54,194	$ (616,873)	$ (193,966)	$ (251,456)	$ (183,101)
Mankato Own_EC2040	$ (62,047)	$ (47,046)	$ 17,486	$ 41,183	$ 45,689	$ 38,110	$ 32,129	$ (22,380)	$ 57,072	$ (222,948)	$ (45,320)	$ (45,567)	$ 22,637
Mankato Own_EC2050	$ (184,377)	$ (182,246)	$ (158,018)	$ (167,756)	$ (163,101)	$ (136,982)	$ (32,740)	$ (211,442)	$ 101,182	$ (601,175)	$ (170,285)	$ (207,924)	$ (139,588)

Scenario Definitions

All "EC" Scenarios	Monticello retires in 2030, Prairie Island 1 retires in 2033, Prairie Island 2 retires in 2034, A.S. King retires in 2028, and Sherco 3 retires in 2030.
Mankato Base_EC	MEC remains under the PPAs; MEC I PPA expires in 2026, MEC II PPA expires in 2039.
Mankato Own_EC	MEC is purchased by Xcel and operates as 2x1 into 2046 and as a 1x1 into 2054.
Mankato Own_EC2040	MEC is purchased by Xcel and operates as 2x1 through 2040.
Mankato Own_EC2050	MEC is purchased by Xcel and operates as 2x1 into 2046 and as a 1x1 through 2050.

Result Definition

Xcel purchase decreases costs	$ (100,000)
Xcel purchase increases costs	$ 100,000
Result within a margin of error (± 0.05%)	$ -

CERTIFICATE OF SERVICE

I, Linda Chavez, hereby certify that I have this day served copies of the following document on the attached list of persons by electronic filing, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

MINNESOTA DEPARTMENT OF COMMERCE – SUPPLEMENTAL COMMENTS

Docket Nos. **IP6949,E002/PA-18-702**

Dated this **26th** day of **July, 2019**.

/s/Linda Chavez
____

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Jorge	Alonso	jorge.alonso@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 55101	Electronic Service	No	OFF_SL_18-702_Official Service List
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_18-702_Official Service List
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	OFF_SL_18-702_Official Service List
Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy	414 Nicollet Mall Fl 5 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_18-702_Official Service List
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Tracy	Bertram	tbertram@ci.becker.mn.us		12060 Sherburne Ave Becker City Hall Becker, MN 55308-4694	Electronic Service	No	OFF_SL_18-702_Official Service List
James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_18-702_Official Service List
Michael J.	Bull	mbull@mncee.org	Center for Energy and Environment	212 Third Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_18-702_Official Service List
James	Canaday	james.canaday@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota St. St. Paul, MN 55101	Electronic Service	No	OFF_SL_18-702_Official Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Thomas	Carlson	thomas.carlson@edf-re.com	EDF Renewable Energy	10 2nd St NE Ste. 400 Minneapolis, Minnesota 55413	Electronic Service	No	OFF_SL_18-702_Official Service List
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_18-702_Official Service List
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_18-702_Official Service List
Riley	Conlin	riley.conlin@stoel.com	Stoel Rives LLP	33 S. 6th Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_18-702_Official Service List
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_18-702_Official Service List
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