BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY, D/B/A XCEL ENERGY, FOR A CERTIFICATE OF NEED FOR ADDITIONAL DRY CASK STORAGE AT THE MONTICELLO NUCLEAR GENERATING PLANT INDEPENDENT SPENT FUEL STORAGE INSTALLATION	MPUC Docket No. E002/CN-21-668 OAH Docket No. 8-2500-38129

DIRECT TESTIMONY AND ATTACHMENTS OF SACHIN SHAH

ON BEHALF OF

THE DIVISION OF ENERGY RESOURCES OF
THE MINNESOTA DEPARTMENT OF COMMERCE

MARCH 1, 2023

DIRECT TESTIMONY AND ATTACHMENTS OF SACHIN SHAH
IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY, D/B/A XCEL ENERGY, FOR A CERTIFICATE OF NEED FOR ADDITIONAL DRY CASK STORAGE AT THE MONTICELLO NUCLEAR GENERATING PLANT INDEPENDENT SPENT FUEL STORAGE INSTALLATION

MPUC DOCKET NO. E002/CN-21-668
OAH DOCKET NO. 8-2500-38129

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I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Sachin Shah. I am a Public Utilities Rates Analyst with the Minnesota Department of Commerce, Division of Energy Resources, Energy Regulation and Planning (Department or DOC). My business address is 85 7th Place East, Suite 280, Saint Paul, Minnesota 55101.

Q. What is your educational and professional background?

A. A summary of my educational and professional background is presented in Ex. DOC-__, SS-D-1 (Shah Direct).

II. PURPOSE

Q. What is the purpose of your testimony in this proceeding?

A. My testimony addresses two subparts of Certificate of Need (CN) criteria established in Minnesota Rules part 7855.0120. Specifically, I consider:

- 7855.0120 A(1), which concerns the accuracy of the applicant's forecast of demand for the type of energy or service that would be supplied by the proposed facility; and
- 7855.0120 C(1), which concerns the relationship of the proposed facility, or a suitable modification thereof, to overall state energy needs.

Q. How is your testimony organized?

A. My testimony addresses Northern States Power d/b/a Xcel Energy's (Xcel, or the Company) proposed project (Project) in two parts. The first part discusses the accuracy of Xcel's demand and energy forecast. The second part discusses the Project's expected overall impacts on the State of Minnesota's (State) energy and capacity needs (which I refer to as "energy need" in this testimony).

III. REVIEW OF XCEL'S FORECASTS

Q. Please describe recent forecasts that Xcel has provided to the Commission.

A. Xcel is required to submit biennial Integrated Resource Plans (IRP) for Minnesota Public Utilities Commission (Commission) review and approval. The IRP process permits the Commission and stakeholders to examine a utility's current and planned electricity generation for the next 15 years.[1] In addition to IRPs, Xcel must produce forecasts on an annual basis.[2]

Q. Did the Department raise any concerns with Xcel's most recent IRP forecast?

A. Yes. In Xcel's most recent IRP proceeding (Docket No. E002/RP-19-368), the Department examined the accuracy of Xcel's forecasting over the past 15 years. The Department concluded that the Company's demand and energy forecasts have a systematic bias. Specifically, as shown in Table 1 below, about 89.1% of Xcel's demand forecast

[1] Minn. Pub. Utils. Comm'n, *Resource Planning* (last updated Feb. 2023), https://mn.gov/puc/activities/economic-analysis/resource-planning. Minn. R. 7843. Minn. Stat.§ 216B.2422 Subd. 2

[2] Minn. R. 7610.0300.

variances were too high and approximately 65.1% of Xcel's energy forecast variances were high. Consequently, for that IRP, the Department adjusted Xcel's forecast to account for this systematic bias and used the adjusted forecasts as inputs in the capacity expansion plans used by the Department. Those capacity expansion plans utilized the EnCompass modeling software.[3]

Table 1: 2019v2.3 Forecast

Xcel Forecast Vintage	Data Points	%	Data Points	%
2019v2.3	Demand		Energy	
Fcast Too Low	14	10.9	44	34.9
Fcast Too High	115	89.1	82	65.1
Correct	0	0.0%	0	0.0%

Q. How did the Department conduct its forecast analysis in the IRP proceeding?

A. Because the purpose of analysis was to establish an acceptable base forecast for long term planning purposes, and to do so quickly, the Department focused on evaluating the accuracy of Xcel's forecasts. Based on reviewing 15 years of data, the Department concluded that Xcel's demand and energy forecasts had a systematic bias (as shown above) and consequently made adjustments before using these forecasts as inputs into its capacity expansion modeling.[4]

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[3] *In re the Application of Northern States Power Company d/b/a Xcel Energy's 2020-2034 Upper Midwest Integrated Resource Plan.*, MPUC Docket E002/RP-19-368 and Department February 11, 2021, Comments at 6-26. (Feb. 2021 Comments) (eDocket ID: 20212-170853-02). *See* Ex. DOC-__, SS-D-2 (Shah Direct).

[4] *In re the Application of Northern States Power Company d/b/a Xcel Energy's 2020-2034 Upper Midwest Integrated Resource Plan.*, MPUC Docket E002/RP-19-368 and Department October 15, 2021, Comments at 9-13. (Oct. 2021 Comments) (eDocket ID: 202110-178845-01). *See* Ex. DOC-__, SS-D-2 (Shah Direct).

Q. Did Xcel rely on the same forecast in its CN application for the proposed project?

A. Yes. Xcel used the same forecast vintage that it identified as "2019 v2.3 forecast". See Xcel's response to Department Information Request Nos. 8, 10, 11, 13, and 15 included as Ex. DOC-__, SS-D-3 (Shah Direct).

Q: Was your review of the CN application similarly focused?

A. Yes. In this case, as in the IRP proceeding, I focused on evaluating the accuracy of Xcel's forecasts and did not review the technical details of Xcel's forecasts nor test all the Company's previous or current statistical models.

Q. Did Xcel provide an update to its responses regarding the forecast variances, including providing additional forecast vintages that it had developed?

A. Yes. Xcel stated the following:

> The attachments were updated for forecast vintages developed in March 2019, July 2019, March 2020, July 2020, March 2021, and July 2021. This update also includes the extension of the forecast horizon to 2021 for the provided forecasts developed from October 2008 through 2021.

See Xcel's response to Department Information Request No. 10, included as Ex. DOC-__, SS-D-3 (Shah Direct).

Q. Please summarize your review of Xcel's updated response.

A. I analyzed the updated Xcel's forecast vintages and concluded once again that the forecasts had a systematic bias as shown below in Table 2.

Table 2: Additional Forecast Vintages

Additional Xcel Forecast Vintages	Data Points	%	Data Points	%
Fcast Too Low	18	8.6	57	27.9
Fcast Too High	192	91.4	147	72.1
Correct	0	0.0%	0	0.0%

Q. Did Xcel provide updated forecasts, and did you review them?

A. Yes. Xcel provided two vintages of updated forecasts, namely forecast vintages that Xcel identified as "2022 v1.0 forecast" and "2022 v2.0 forecast". See Xcel's response to Department Information Request Nos. 11 and 15, included as Ex. DOC-__, SS-D-3 (Shah Direct). My review was the same and consistent with what I did in the IRP proceeding in Docket 19-368. I also observed the following annual average growth rates shown in Table 3 below.

Table 3: Comparison Between Forecast Vintages

Xcel Forecast Vintages	Avg Ann Growth Rate %	
	Demand	Energy
2019v2.3 (2020-2034)	0.7	0.2
2022v1.0 (2022-2037)	0.3	0.3
2022v2.0 (2023-2038)	0.5	0.9

Based on these growth rates, I observe that the differences in demand growth rates between the latest forecast vintage and the base forecast vintage of "2019v2.3" used in both the IRP and this CN proceeding, would be captured in the forecast adjustments made by Department to the Company's demand forecasts in the capacity expansion models used in the IRP proceeding.

Q. Please explain how the changes between the "2019v2.3 forecast" and the latest "2022v2.0 forecast" are accounted for in the forecast adjustments made by Department.

A. Sure. In the IRP proceeding, the Department assumed that the Company's base forecast represented the high end of a forecast band and imposed a downward adjustment on Xcel's forecast results. Xcel's forecasted estimated annual average demand growth of 0.5% in the latest 2022v2.0 vintage falls within the Department's adjusted range. See Ex. DOC-__, SS-D-2 at 24, 43 (Shah Direct). However, the estimated annual average energy growth forecasted by Xcel compared between 0.2% in the 2019v2.3 vintage versus the 0.9% from the latest 2022v2.0 vintage, all else being equal, would favor the proposed project.

Q. Do you propose using the most recent forecast vintage in this proceeding for the proposed project?

A. No. I recommend against the use of the most recent forecast vintage for the following reasons. First, the Company's forecasts have been overly optimistic and have a systematic bias as explained in the Department's IRP comments in Docket 19-368, included as Ex. DOC-__, SS-D-2 (Shah Direct), and as shown above.

Second, as explained earlier, the Department already adjusted the Demand and Energy forecasts used in the capacity expansion models in the IRP proceeding.

Third, the above changes in the demand growth rates between the "2019v2.3 forecast" vintage used in both the IRP proceeding and, in this docket, and the latest "2022v2.0 forecast" vintage would already be captured in the adjustments made by the Department. Finally, using the much higher energy growth rate along with a demand growth rate from the "2022v2.0 forecast" vintage that is slightly lower compared to the "2019v2.3 forecast" vintage used in this proceeding, an adjustment to the forecast, all else being equal would favor the proposed project.

Q. Please provide your conclusion on the accuracy of Xcel's forecast used in this docket.

A. Based on the above discussion and analysis, I conclude that Xcel's forecast is systematically biased and optimistic or overstated. The Department, however, adjusted its capacity expansion modeling in the 2019 IRP proceeding to account for Xcel's systematic bias. The Commission also had the benefit of this information when the Commission concluded that "Xcel may pursue extending the operating life of the Monticello Nuclear Generating Plant by ten years."[5]

Q. Do you address the capacity expansion models used in the IRP proceeding or in this docket?

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[5] *In re 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy*, Docket No. E-002/RP-19-368, ORDER APPROVING PLAN WITH MODIFICATIONS & ESTABLISHING REQUIREMENTS FOR FUTURE FILINGS at 32 (Apr. 15, 2022).

A. No. That aspect of the capacity expansion modeling is addressed by Dr. Steve Rakow.

IV. THE PROPOSED PROJECT'S IMPACT ON STATE ENERGY NEEDS

Q. Please provide your general assessment of Minnesota's energy and capacity needs.

A. The Department recently reviewed the IRPs from three investor-owned utilities operating in the State: Xcel,[6] Minnesota Power (MP),[7] and Otter Tail Power Company (OTP).[8] During those reviews, the Department concluded that all the utilities showed the likelihood of increased capacity and energy needs during the 2023 – 2028 timeframe. Also, Great River Energy filed its IRP in 2017[9] and a subsequent extension request due to changed circumstances and showed increased capacity and energy needs.[10] Since the above four utilities serve the majority of energy needs in the State and all of them are likely to need capacity and energy during the 2023-2028 timeframe, I conclude that the State needs more capacity and energy during the 2023-2028 timeframe. I further reviewed the four utilities' *Minnesota Electric Utility Annual Report* (Reports) filed in June and July 2022, to confirm this conclusion with the most up-to-

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[6] Docket No. E002/RP-19-368

[7] Docket No. E015/RP-21-33

[8] Docket No. E017/21-339. OTP initially filed on September 1, 2021 and the Commission on November 1, 2022 issued its Notice of Extended Comment Period with a deadline for OTP to file its Updated IRP by March 31, 2023.

[9] Docket No. ET2/RP-17-286 and see *In re the Matter of Great River Energy's 2018-2032 Integrated Resource Plan.*, MPUC Docket ET2/RP-17-286, ORDER ACCEPTING 2018-2032 RESOURCE PLAN AND SETTING FUTURE FILING REQUIREMENTS, (Nov. 28, 2018) (2017 GRE IRP Order), eDocket ID: 201811-148088-01. Also See *In re the Matter of Great River Energy's 2022-2036 Integrated Resource Plan and In the Matter of Great River Energy's Request For an Extension for Filing its Next Integrated Resource Plan.*, MPUC Docket ET2/RP-17-286 and MPUC Docket ET2/RP-22-75, ORDER GRANTING EXTENSION AND REQUIRING INTERIM FILING, (April. 12, 2022) (2022 GRE IRP Order), eDocket ID: 20224-184645-01.

[10] On January 21, 2022, Great River Energy (or the Cooperative) filed a request to extend the deadline for its 2022–2036 integrated resource plan (resource plan) from April 1, 2022, to April 1, 2023.

date information.[11] The Reports support my conclusion on the general assessment of the State's energy needs during the 2023 -2028 timeframe.

Q. Please summarize observations from the utilities' IRPs relating to energy and capacity needs.

A. The Department recently reviewed the most recently filed IRPs that indicates that Minnesotans are expected to have slight changes in their electricity requirements as follows:

- Xcel's IRP includes a 0.2 percent annual average energy growth rate for 2020 to 2034;[12]
- MP's IRP includes a -0.4 percent annual average energy decline for 2019 to 2034;[13] and
- OTP's IRP includes a 0.46 percent annual average energy growth rate, prior to conservation programs.[14]

However, all three utilities are proposing retirements of large baseload coal units:

- Xcel is proposing to retire the Allen S. King and Sherburne County Generating Station unit 3;
- MP is proposing to retire Boswell Energy Center unit 3; and
- OTP is proposing to withdraw its 35 percent ownership interest in Coyote Station.

Additionally, the Commission's September 23, 2021 Order Granting Certificate of Need and Issuing Site Permit and Route Permit (Plum Creek Order) in Docket Nos. IP6697/CN-18-699, IP6697/WS-18-700, and IP6697/TL-18-701, in part stated that:

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[11] See Docket E999/M-22-11.
[12] See Xcel's June 30, 2020 Supplement: 2020-2034 Upper Midwest Integrated Resource Plan at Attachment A, Table II-1 in Docket No. E002/RP-19-368. eDocket ID:20206-164371-02.
[13] See MP's 2021 Integrated Resource Plan at page 21, filed February 1, 2021 in Docket No. E015/RP-21-33.
[14]See OTP's Application for Resource Plan Approval at page 15, filed September 1, 2021 in Docket No. E017/RP-21-339.

> Furthermore, utilities plan to retire coal-based generating units across the region in the coming years, and renewable energy sources are expected to fill some of the resulting capacity needs. These established goals and plans are strong evidence of a utility's intention for future energy development and can be used to demonstrate demand, especially when consistent with stated public policy goals.

Q. Has the Commission decided Xcel's IRP in Docket 19-368?

A. Yes. In its 2022 Xcel IRP Order, the Commission in Ordering paragraph 2 in part, stated the following:[15]

> 2. Regarding Xcel's 2020–2034 Upper Midwest Integrated Resource Plan, the Commission finds as follows:
>
> A. Xcel's Alternate Plan as filed on June 25, 2021, is approved for planning purposes, and the following elements are specifically approved:
>   1) Each year through 2034, Xcel shall save at least 780 gigawatt-hours via energy efficiency.
>   2) Xcel shall continue to acquire 400 megawatts of incremental demand response by 2023 as ordered in the company's last resource plan.
>   3) In 2025 and 2026, Xcel shall repower resources needed for blackstart services.
>   4) Xcel shall retire the Allen S. King Generating Station in 2028, and Sherburne County Generating Station Unit 3 in 2030. …

In addition, Xcel indicated in its June 30, 2020 Supplement in Docket 19-368[16] that its share of Sherco Unit 3 capacity is approximately 517 MW, and Allen S King's capacity is

[15] Docket No. E002/RP-19-368 and see *In re the Matter of Northern States Power Company d/b/a Xcel Energy 2020-2034 Integrated Resource Plan.*, MPUC Docket E02/RP-19-368, ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE FILINGS, (April. 15, 2022) (2022 XCEL IRP Order), eDocket ID: 20224-184828-01.
[16] See Xcel's June 30, 2020 Supplement: 2020-2034 Upper Midwest Integrated Resource Plan at Attachment A, Tables V-1, V-3, and V-5 in Docket No. E002/RP-19-368. eDocket ID:20206-164371-02.

511 MW. In addition, Sherco Unit 1 with a capacity of 680 MW is slated for retirement in 2026. Sherco Unit 2 with a capacity of 682 MW is slated for retirement in 2023. Xcel also has approximately 500MW Power Purchase Agreement (PPA) with Manitoba Hydro with a current contract expiration date of 2025. In addition, its Mankato Energy Center Unit 1 and Cannon Falls PPAs have a capacity of 375 MW and 358 MW; with a current contract expirations in 2026, and 2025 respectively. Xcel also has approximately 871 MW of currently planned retirements of its Wheaton, Blue Lake and Inver Hills facilities between 2023-2026.

Q. Has the Commission decided MP's IRP in Docket 21-33?

A. Yes. In its 2023 MP IRP Order, the Commission in Ordering paragraph 2 in part, stated the following:[17]

> 2. Minnesota Power must cease coal operations at Boswell Unit 3 at the latest by December 31, 2029, and Boswell Unit 4 by 2035. Capacity and energy replacement options including transmission solutions for both units will be evaluated during the next resource plan. …

Q. How does this information concerning the utilities' IRPs relate to the Commission's consideration of this case?

A. As mentioned above, there are not only large baseload coal units that are slated for retirement but there are other potential PPA retirements amongst others, in Xcel's IRP

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[17] Docket No. E015/RP-21-33 and see *In re the Matter of Minnesota Power's 2021-2035 Integrated Resource Plan.*, MPUC Docket E015/RP-21-33, ORDER APPROVING PLAN AND SETTING ADDITIONAL REQUIREMENTS, (Jan. 9, 2023) (2023 MP IRP Order), eDocket ID: 20231-191970-01.

as indicated above. As a result, this would indicate that the proposed project will have a positive impact in meeting the State's energy needs.

Q. Why don't you provide specific numbers instead of a general assessment of the State of Minnesota's energy need?

A. The type of energy needed (baseload, intermediate, peaking) for each utility cannot be identified by simply checking the total energy need. Obtaining such specific numbers requires more complicated processes (involving, for example, cost minimizing capacity expansion modeling) to evaluate the type of energy needed. Also, the evaluation of energy need is a utility-specific process since the analysis depends on a utility's existing generation fleet, purchased power contracts, fuel acquisition processes and procurement policies and processes to satisfy future needs. For utilities subject to the Commission's jurisdiction, this specific analysis occurs in integrated resource plans. My testimony references a number of relevant resource plan dockets above in which intensive analysis has been performed to test the utilities' statements regarding load and supply capacity. As such, I do not provide that analysis here. Therefore, I confine my discussion in this testimony to the State's overall energy need in generic terms instead of identifying specific types of energy needed.

Q. What is your opinion of the impact of the Project on the general assessment of the State of Minnesota's energy need?

A. Based on my general assessment of the State's energy need and all the discussion above, I conclude that the proposed Project will have a positive impact in meeting the State's energy need by providing additional energy and capacity to meet the State's energy need.

V. CONCLUSION

Q. Please provide your conclusions.

A. First, based on my analysis I conclude that Xcel's forecasts are systematically biased. However, to account for this bias, Department adjusted the forecasts used as an input in the capacity expansion models in the IRP proceeding. Second, I conclude that the proposed Project will likely have a positive impact to statewide energy need.

Q. Does this conclude your direct testimony?

A. Yes.

Sachin Shah
Minnesota Department of Commerce,
Division of Energy Resources
85 7th Place East, Suite 280
St. Paul, MN55101-2198

EDUCATION

- University of North Carolina-Charlotte, Master of Science, Economics, 1996.
- University of North Carolina-Charlotte, Bachelor of Arts, Major in Economics and Minor in Political Science, 1993

Prior to joining the Department of Commerce from January, 1998 till July, 1999, I worked at a CPA firm in St. Louis where I prepared tax returns and maintained clients' general ledger databases. After leaving the CPA firm I worked as Brokerage Service Associate with American Express Financial Advisors. I Assisted clients and financial advisors with their brokerage account service needs via telephone, provided basic financial market information and processed securities transactions and payment requests. Obtained Series 7 securities registration / license.

EXPERIENCE AT DEPARTMENT OF COMMERCE, DIVISION OF ENERGY RESOURCES

I have been employed as a Rates Analyst with the Department of Commerce, Division of Energy Resources (DOC-DER) since February, 2000. During my time with the Department of Commerce, Division of Energy Resources I have been assigned a wide variety of filings dealing with a number of different issues. For example:

As a rates analyst for the Department of Commerce, Division of Energy Resources, my duties have included evaluating comments on different issues, such as investigating and filing testimony and comments for forecasting in:

- UtiliCorp United Inc.'s Request for an Increase in Rates in Docket No. G007,011 /GR-00-951;
- Great Plains Request for an Increase in Rates in Docket No. G004/GR-02-1682;
- Hutchinson Utilities Commission's Certificate of Need proceeding in Docket No. G252/CN-01-1826;
- Dakota Electric's Request for an Increase in Rates in Docket No. E111/GR-03-261;
- Interstate Power and Light Company’s Request for an Increase in Electric Rates in Docket No. E001/GR-03-767;
- CenterPoint Energy Minnegasco, a Division of CenterPoint Resources Corp., Request for an Increase in Rates in Docket No. G008/GR-04-901;
- Northern States Power Company d/b/a Xcel Energy Request for an Increase in Rates in Docket No. G002/GR-04-1511;
- Montana Dakota Utilities d/b/a Great Plains Request for an Increase in Rates in Docket No. G004/GR-04-1487;
- Alliant Energy d/b/a Interstate Power and Light Company’s Resource Plan in Docket No. E001/RP-05-2029;
- Great River Energy’s Resource Plan in Docket No. ET2/RP-08-784;
- Dakota Electric's Request for an Increase in Rates in Docket No. E111/GR-09-175;
- Northern States Power Company d/b/a Xcel Energy Request for an Increase in Rates in Docket No. G002/GR-09-1153;
- Interstate Power and Light Company’s Request for an Increase in Electric Rates in Docket No. E001/GR-10-276;
- Alliant Energy d/b/a Interstate Power and Light Company’s Resource Plan in Docket No. E001/RP-08-673;
- Minnesota Power and Great River Energy’s Certificate of Need proceeding in Docket No. ET2, E015/CN-10-973;
- Xcel Energy’s Certificate of Need proceeding in Docket No. E002/CN-11-332;
- Xcel Energy’s Certificate of Need proceeding in Docket No. E002/CN-12-113;
- Minnesota Power’s Resource Plan in Docket No. E015/RP-13-53;
- In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need in Docket No. E002/CN-12-1240; and
- Northern States Power Company d/b/a Xcel Energy Request for Authority to Increase Rates for Electric Service in Minnesota in Docket No. E002/GR-13-868;
- Minnesota Power’s Certificate of Need proceeding in Docket No. E015/CN-12-1163;
- Xcel Energy’s Resource Plan in Docket No. E002/RP-15-21;
- Minnesota Power’s Resource Plan in Docket No. E015/RP-15-690;
- Minnesota Energy Resources Corporation’s Request for Authority to Increase Rates for Natural Gas Service in Minnesota in Docket No. G011/GR-15-736;
- Northern States Power Company d/b/a Xcel Energy Request for Authority to Increase Rates for Electric Service in Minnesota in Docket No. E002/GR-15-826;
- Minnesota Power’s Request for Authority to Increase Rates for Electric Service in Minnesota in Docket No. E015/GR-16-664;
- Minnesota Energy Resources Corporation’s Request for Authority to Increase Rates for Natural Gas Service in Minnesota in Docket No. G011/GR-17-563;
- Great Plains Natural Gas Co., a Division of MDU Resources Group Inc., for Authority to Increase Rates for Natural Gas Service in Minnesota in Docket No. G004/GR-19-511;
- CenterPoint Energy Resources Corp., D/B/A. CenterPoint Energy Minnesota Gas, for Authority to Increase Natural Gas Rates in Minnesota in Docket No. G008/GR-19-524;
- Xcel Energy’s Resource Plan in Docket No. E002/RP-19-368;
- Otter Tail Power Company, for Authority to Increase Rates for Electric Service in Minnesota in Docket No. E017/GR-20-719;
- Minnesota Power’s Request for Authority to Increase Rates for Electric Service in Minnesota in Docket No. E015/GR-21-335; and
- Northern States Power Company d/b/a Xcel Energy Request for Authority to Increase Rates for Electric Service in Minnesota in Docket No. E002/GR-21-630.

My duties have also included reviewing miscellaneous rate and fuel procurement filings involving gas utilities, for example, evaluating Demand Entitlement and True-up filings. I was previously responsible for producing the Quarterly PGA summary and producing and coordinating the publication of the DOC-DER's Annual Fuel Reports (Gas). I have also provided testimony on natural gas in The Matter of Application of Mankato Energy Center, LLC, A Wholly Owned Subsidiary of Calpine Corporation, for a Certificate of Need for A Large Electric Generating Facility in Docket No. IP6345/CN-03-1884. I have also worked on various Rider Petitions such as in Docket Nos. E002/M-15-805, E015/M-14-990, E015/M-15-876, and G004/M-19-273. I have also worked on various Renewable Natural Gas Petitions such as in Docket Nos. G008/M-18-547 and G008/M-20-434. I also provided testimony on CenterPoint's proposed Cost of Gas in Docket G008/GR-21-435.

SEMINARS

National Association of Regulatory Utility- Commissioners' 42ntl Annual Regulatory Studies Program, Institute of Public Utilities, Michigan State University, 2000

February 11, 2021 **PUBLIC DOCUMENT**

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, Minnesota 55101-2147

RE: **PUBLIC Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E002/RP-19-368

Dear Mr. Seuffert:

Attached are the Comments of the Minnesota Department of Commerce, Division of Energy Resources (Department), in the following matter:

2020-2034 Upper Midwest Integrated Resource Plan.

The Petition was filed on July 1, 2019 (as supplemented on June 30, 2020) by:

Christopher B. Clark
President
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401

The Department recommends that the Minnesota Public Utilities Commission (Commission) **approve the petition with modifications**. The Department's team of Danielle Winner, Matthew Landi, Sachin Shah and myself is available to answer any questions that the Commission may have in this matter.

Sincerely,

/s/ Steve Rakow
Analyst Coordinator

SR/ar
Attachment

Table of Contents

Before the Minnesota Public Utilities Commission

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

Docket No. E002/RP-19-368

I. INTRODUCTION

A. DOCKET HISTORY

1. First Round

On July 1, 2019 Northern States Power Company-Minnesota (NSP-M), doing business as Xcel Energy (Xcel or the Company) filed the Company's *2020-2034 Upper Midwest Integrated Resource Plan* (Petition). The Petition was filed in compliance with the Minnesota Public Utilities Commission's (Commission) January 30, 2019 *Order Extending Deadline for Filing Next Resource Plan* (2019 Order) and January 11, 2017 *Order Approving Plan with Modifications and Establishing Requirements for Future Resource Plan Filings* (2017 Order) in Docket No. E002/RP-15-21.

On July 3, 2019 the Commission issued its *Notice of Comment Period* (Notice) which stated that comments on the Petition are due November 8, 2019 and January 8, 2020. The Notice also indicated that comments on completeness were due August 1, 2019.

On July 18, 2019 the Commission issued its *Order Requiring Bill Insert and Referring Matter to OAH for Public Meeting* (Meeting Order). The Meeting Order established a process for holding public meetings to ensure that Xcel's customers have an opportunity to participate in the IRP process.

On July 25, 2019 the Department filed a letter recommending that the Commission not undertake a completeness review.

In response to the Meeting Order, on July 30, 2019 the Minnesota Office of Administrative Hearings (OAH) issued OAH's *Scheduling Order*, establishing October 21, 23, 28, and 30 as dates for public meetings.

On July 31, 2019 the city of Minneapolis filed a letter on completeness.

On October 8, 2019 Xcel filed a letter indicating that the Company could:

- provide updated Strategist modeling in a new filing by December 6, 2019;
- participate with other utilities in a planning meeting to cover the new capacity expansion modeling (CEM) tool (Encompass), along with a variety of topics; and
- provide a supplemental filing in the April 2020 timeframe using EnCompass.

On or about October 15, 2019 the following organizations and coalitions filed comments on modifying the comment deadlines:

- Sierra Club, Vote Solar, and the Institute for Local Self-Reliance;
- Clean Energy Organizations (CEO);[1]
- Citizens Utility Board of Minnesota;
- Xcel Large Industrials (XLI);[2]

On November 12, 2019 the Commission issued its *Order Suspending Procedural Schedule and Requiring Additional Filings* (Supplemental Order). The Supplemental Order:

- suspended the procedural schedule;
- required Xcel to file certain supplemental information; and
- delegated to the Executive Secretary the establishment of a new procedural schedule—but stated that Xcel's supplement could be filed no later than July 1, 2020.

On December 18, 2019 the OAH filed its *Report Summarizing Public Meetings* which summarized the public comments obtained at the October public meetings regarding the Petition.

2. Second Round

On December 6, 2019 the Commission issued a notice indicating that:

- Xcel must file a supplement by April 1, 2020;
- comments are due August 3, 2020; and
- reply comments are due October 2, 2020.

On February 12, 2020 the Minnesota Sustainable Growth Coalition (MSG) filed comments on behalf of MSG's non-utility members regarding Xcel's proposed plan.[3]

On March 6, 2020 Xcel filed the Company's *Extension Request*, requesting an extension for the supplemental filing to May 15, 2020 in light of the need to conduct a substantial update of the Strategist modeling, and to implement the EnCompass model, including development of more granular modeling inputs for hourly analysis.

On March 11, 2020 the Commission issued its *Notice Approving Extension Request and Extending Comment Periods* establishing a new deadline for Xcel's supplement and for filing initial comments and reply comments.

On March 13, 2020 International Brotherhood of Electrical Workers locals 23, 160, and 949 filed comments regarding Xcel's proposed plan.

[1] The CEO coalition consists of Clean Grid Alliance, Fresh Energy, Minnesota Center for Environmental Advocacy, and the Union of Concerned Scientists.
[2] The XLI coalition consists of Covia Holdings Corporation; Flint Hills Resources Pine Bend, LLC; Gerdau Ameristeel US Inc.; Marathon Petroleum Corporation; and USG Interiors, Inc.
[3] MSG's non-utility members come from the private, public, and non-profit sectors.

On April 10, 2020 Xcel filed the Company's *Extension Request*, requesting a second extension for the supplemental filing to June 30, 2020 in light of the ongoing COVID-19 public health emergency.

On April 16, 2020 the Commission issued its *Second Notice Approving Extension Request and Extending Comment Periods* stating that:

- the deadline for Xcel's supplement is June 30, 2020;
- the deadline for filing initial comments is October 30, 2020; and
- the deadline for filing reply comments is January 15, 2021.

On June 30, 2020 Xcel filed the Company's *Supplement to the Petition* (Supplement).

On September 15, 2020, at the request of the Department, the Commission established January 15, 2021 as the due date for comments and March 15, 2021 as the due date for reply comments.

On December 23, 2020 the Department issued Global Energy & Water Consulting, LLC's (Global) *Independent Investigation of Cost Overruns and Cost Estimates for Xcel Energy's Monticello and Prairie Island Nuclear Power Plants* (Report). The Department retained Global to prepare the Report in compliance with the Commission's March 26, 2019 *Order Authorizing Commissioner of Commerce to Seek Funding For Specialized Technical Professional Services Under Minn. Stat. § 216B.62 Subd. 8* in Docket Nos. E002/RP-15-21 and E002/GR-15-826:

> The Commission authorizes the Commissioner of the Department of Commerce to seek authority from the Commissioner of Management and Budget to incur costs for specialized technical professional investigative services under Minn. Stat. § 216B.62, subd. 8, to continue investigating the causes of cost increases related to Xcel's Prairie Island and Monticello nuclear facilities and to assist the Department in Xcel's upcoming integrated resource plan and rate case proceedings.

On December 28, 2020, at the Department's request, the Commission established February 11, 2021 as the due date for comments and April 12, 2021 as the due date for reply comments.

In January and February, 2021, comments were filed by MSG on behalf of MSG's non-utility members; the Prairie Island Indian Community, a federally recognized Indian tribe; Goodhue County Board of Commissioners; the St. Paul Area Chamber; Board of Wright County Commissioners; Northern Natural Gas; and other organizations.

Numerous members of the public filed comments throughout this proceeding.

B. COMPANY BACKGOUND

The Petition and Supplement cover Xcel's upper Midwest service territory, including parts of Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin. According to the U.S. Energy Information Administration's Form 861 for 2017, NSP-M has about 1.46 million electricity customers in total, spread across Minnesota (1.28 million), North Dakota (90,000), and South Dakota (90,000). Xcel's Wisconsin subsidiary has about 257,000 electricity customers located in Michigan (9,000) and Wisconsin (248,000). NSP-M electricity customers in Minnesota are primarily located in the twin cities area, but Xcel also provides electricity to customers in St. Cloud, Red Wing, Mankato, and several other communities.

The Company planned to meet an estimated peak demand of about 10.4 GW before energy efficiency and load management in 2018. In addition, the Company must have about 0.3 GW of resources above peak demand to meet reliability requirements. The portfolio of resources used to meet this peak demand and reliability requirements in 2018 included:

- 1.3 GW of energy efficiency;
- 0.8 GW of load management;
- 12.7 GW[4] of supply-side resources, including;
  - 0.7 GW of hydro;
  - 0.6 GW of solar;[5]
  - 2.7 GW of wind;[6]
  - 2.4 GW of coal;
  - 1.7 GW of nuclear;
  - 2.0 GW of natural gas combined cycle (CC);
  - 2.0 GW of natural gas combustion turbine (CT);
  - 0.4 GW of fuel oil CT; and
  - 0.2 GW of other fuels.[7]

C. XCEL'S RESOURCE NEEDS

Table 1 below, taken from Table 2-2 in Xcel's Supplement, shows the Company's projected resource needs over the planning period. These are the needs before any new actions. For example, it considers existing and approved resources only and takes into account current unit retirement and contract expiration dates. This means Table 1 assumes the Company's nuclear units operate to the end of the current license life and committed units come on-line (such as the 728 MW Sherco combined cycle generating unit (Sherco CC) in 2027).

[4] For reliability purposes supply-side resources are measured using "unforced capacity." Unforced capacity is equal to the installed capacity less a discount factor which accounts for periods when the power plant is not operational (forced outages). For larger, dispatchable resources the discount factor calculated by MISO is typically less than 15 percent.
[5] Solar resources are typically measured using a discount factor for reliability purposes of about 50 percent as calculated by MISO.
[6] Wind resources are typically measured using an 80 percent to 85 percent discount for reliability purposes as calculated by MISO.
[7] Other includes biomass, landfill gas, refuse-derived fuel (RDF), and methane digesters. All data taken from the file SO - _SCENARIO 1.xlsm, provided in response to Department IR No. 4.

Table 1: Xcel's Resource Needs 2020-2034

Year	Resource Need (MW)
2020	1,394
2021	1,871
2022	2,002
2023	2,052
2024	1,311
2025	195
2026	(92)
2027	(334)
2028	(386)
2029	(365)
2030	(1,016)
2031	(1,605)
2032	(1,945)
2033	(2,602)
2034	(3,166)

Table 1 shows that Xcel expects a need to acquire new capacity resources—or extend the life of current resources—around 2026 or 2027. However, substantial resource needs are not encountered until 2030.

D. XCEL'S PROPOSED ACTION PLAN

In the Supplement, Xcel proposed the following five-year (2020-2024) action plan. Overall, the Company's preferred plan does not identify any incremental capacity needs through 2024. Thus, the majority of Xcel's proposed actions address previously approved or pending resource additions and retirements.

Regarding wind resources, Xcel expected that wind generation resulting from recent acquisitions will achieve commercial operation by 2022. If Xcel encounters opportunities to repower existing resources, or if specific customer needs require procurement, the Company will pursue the opportunities. Finally, Xcel intends to issue a request for proposals (RFP) for repowering of existing wind resources.[8]

Regarding solar resources, Xcel expected to start an RFP process in the 2023 to 2024 timeframe. Xcel has proposed the addition of up to 460 MW of solar capacity, to interconnect at the Sherco substation.[9] This would meet the proposed addition of about 500 MW of large-scale solar resources in 2025 in the Company's preferred plan.[10]

Regarding hydro resources, Xcel will add 125 MW of energy and capacity through an existing, Commission-approved power purchase agreement (PPA) with Manitoba Hydro in 2021.

[8] While the magnitude of the capacity resulting from the RFP cannot be known, Xcel estimates about 800 MW to 1,000 MW could result. See Xcel's June 17 Report in Docket No. E,G999/CI-20-492 for details.
[9] See Xcel's June 17 Report in Docket No. E,G999/CI-20-492 for details.
[10] Note that Xcel included forecasted growth of distributed solar in the overall planning process.

Regarding nuclear resources, Xcel expected to file a certificate of need proposing a life extension at the Monticello Nuclear Generating Plant (Monticello) with the Commission. Xcel also expects to begin working toward a license extension with the U.S. Nuclear Regulatory Commission during this timeframe.

Regarding natural gas and oil resources, Xcel anticipated extending the life of Blue Lake units 1 to 4 through 2023 and continue development of the Sherco CC unit. Finally, the Company notes that Xcel is analyzing the Company's black-start plan. For now, the plan includes costs and capacity associated with black-start facilities.

Regarding coal resources, Xcel proposed to retire the remaining coal units (Sherburne County Generating Station (Sherco) unit 3 and the Allen S. King Generating Plant (King)) by the end of 2030, but after the five-year action plan. Xcel continued to assume Sherco units 1 and 2's currently approved retirement dates of 2026 and 2023.

Regarding load management resources, Xcel proposed to acquire 400 MW by 2023.

Regarding energy efficiency, Xcel proposed to acquire average estimated energy savings of about 780 GWh annually.

Regarding supporting infrastructure, Xcel expected the Huntly-Wilmarth project to be completed in late 2021.[11] Xcel also plans to install new electric meters and supporting infrastructure to facilitate load management and energy efficiency resources.

II. DEPARTMENT ANALYSIS

A. APPLICABLE STATUES AND RULES

The Commission's IRP process is governed by Minnesota Statutes § 216B.2422 which states in part:

> subd. 2. Resource plan filing and approval. (a) A utility shall file a resource plan with the Commission periodically in accordance with rules adopted by the Commission. The Commission shall approve, reject, or modify the plan of a public utility, as defined in section 216B.02, subdivision 4, consistent with the public interest.
>
> …
>
> (c) As a part of its resource plan filing, a utility shall include the least cost plan for meeting 50 and 75 percent of all energy needs from both new and refurbished generating facilities through a combination of conservation and renewable energy resources.
>
> subd. 2a. Historical data and advance forecast. Each utility required to file a resource plan under this section shall include in the filing all applicable annual information required by section 216C.17, subdivision 2, and the rules adopted under that section. To the extent that a utility complies with this subdivision, it is

[11] See Docket No. E002, ET6675/CN-17-184.

not required to file annual advance forecasts with the department under section 216C.17, subdivision 2.

…

subd. 2c. Long-range emission reduction planning. Each utility required to file a resource plan under subdivision 2 shall include in the filing a narrative identifying and describing the costs, opportunities, and technical barriers to the utility continuing to make progress on its system toward achieving the state greenhouse gas emission reduction goals established in section 216H.02, subdivision 1, and the technologies, alternatives, and steps the utility is considering to address those opportunities and barriers.

subd. 3. Environmental costs. (a) The Commission shall, to the extent practicable, quantify and establish a range of environmental costs associated with each method of electricity generation. A utility shall use the values established by the Commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the Commission, including resource plan and certificate of need proceedings.

…

subd. 4. Preference for renewable energy facility. The Commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the Commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest. When making the public interest determination, the Commission must consider:

(1) whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02, the renewable energy standard under section 216B.1691, or the solar energy standard under section 216B.1691, subdivision 2f;

(2) impacts on local and regional grid reliability;

(3) utility and ratepayer impacts resulting from the intermittent nature of renewable energy facilities, including but not limited to the costs of purchasing wholesale electricity in the market and the costs of providing ancillary services; and

(4) utility and ratepayer impacts resulting from reduced exposure to fuel price volatility, changes in transmission costs, portfolio diversification, and environmental compliance costs.

…

> subd. 7. Energy storage systems assessment. (a) Each public utility required to file a resource plan under subdivision 2 must include in the filing an assessment of energy storage systems that analyzes how the deployment of energy storage systems contributes to:
> (1) meeting identified generation and capacity needs; and
>
> (2) evaluating ancillary services.
>
> (b) The assessment must employ appropriate modeling methods to enable the analysis required in paragraph (a).

The Commission's IRP process is also governed by Minnesota Rules parts 7843.0100 to 7843.0600 which states, in part:

> subp. 3. Factors to consider. In issuing its findings of fact and conclusions, the Commission shall consider the characteristics of the available resource options and of the proposed plan as a whole. Resource options and resource plans must be evaluated on their ability to:
> A. maintain or improve the adequacy and reliability of utility service;
> B. keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;
> C. minimize adverse socioeconomic effects and adverse effects upon the environment;
> D. enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and
> E. limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

In summary, the Commission evaluates a proposed IRP based upon its ability to create a reliable, low cost, low environmental and socioeconomic impact system that manages risk. In weighing these factors, the Commission considers the statutory preference for renewable energy facilities. As indicated in the Petition's Attachment A, there are numerous other statutes, rules, and Commission orders which impact the decision in this proceeding.

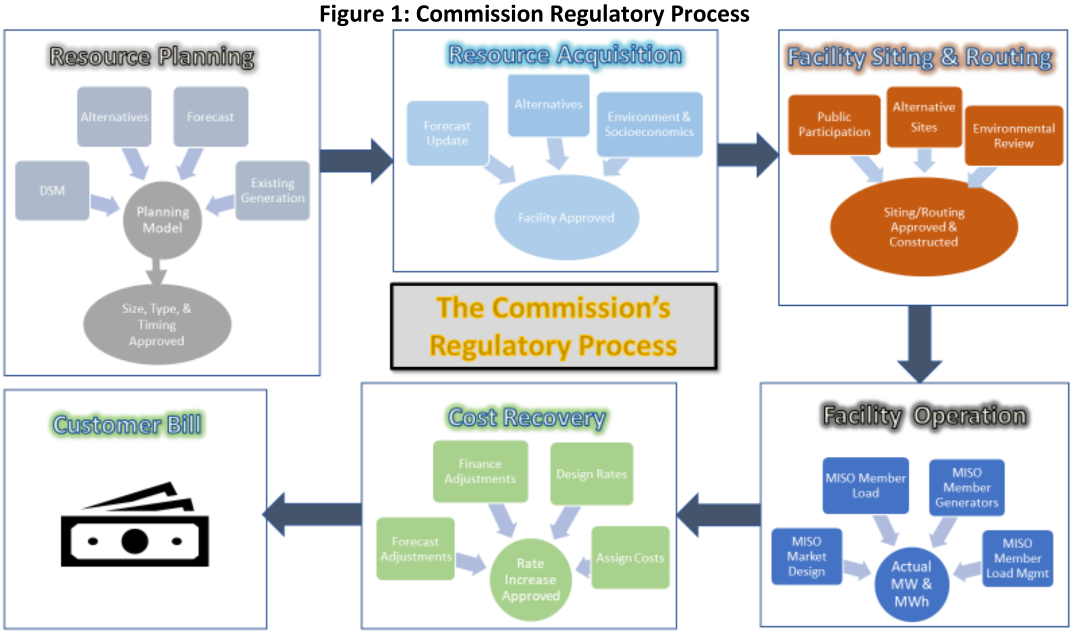
Regarding the proposal to shut down the coal plants early, the Department notes that Minnesota Statutes § 216B.16, subd 6 states:

> If the Commission orders a generating facility to terminate its operations before the end of the facility's physical life in order to comply with a specific state or federal energy statute or policy, the Commission may allow the public utility to recover any positive net book value of the facility as determined by the Commission.

B. OVERVIEW OF DEPARTMENT ANALYSIS

An IRP is the first step in the Commission's overall regulatory process. The Commission's regulatory process as applied to generation units is illustrated in Figure 1 below.

Figure 1: Commission Regulatory Process



For Xcel's 2020-2034 IRP, the Department:

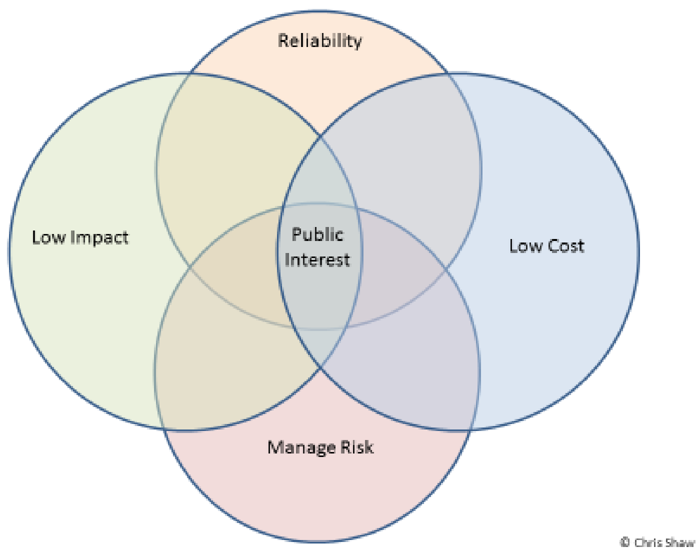
- reviewed the accuracy of the Company's 15-year energy and demand forecast process;[12]
- produced a Department reference case based on changes to Xcel's modeling;
- assessed different scenarios, including various shutdown dates for Sherco unit 3, King, Monticello, and the Prairie Island nuclear generating plant (Prairie Island);
- chose a preferred plan; and
- recommended improvements to the bidding process to acquire resources.

Given the significant surplus that Xcel expects through 2024, the Department was not surprised to find that its modeling resulted in the same five-year action plan as Xcel's—that is no supply-side units are needed.

[12] As discussed further below, this means the Department did not review the technical details of Xcel's forecast. Instead, the Department reviewed the overall accuracy of Xcel's forecast process over the past 15 years.

Similar to Xcel, the Department's recommendation for a preferred plan is based upon the overall resource planning goals of maintaining a reliable, low cost, low impact system that manages risk; this balancing of goals is illustrated in Figure 2 below.

Figure 2: Balancing Four IRP Goals[13]



Under Minnesota Rules 7843.0600, subp. 2 the consequences of the Commission's order in this proceeding are clear:

> the findings of fact and conclusions from the Commission's decision in a resource plan proceeding may be officially noticed or introduced into evidence in related Commission proceedings … In those proceedings, the Commission's resource plan decision constitutes prima facie evidence of the facts stated in the decision."

[13] Each of the four goal is embedded in numerous Minnesota Statutes and Minnesota Rules. For further details see the *Direct Testimony and Attachments of Dr. Steven Rakow* at Department Ex. __ SRR-2 (Docket No. E015/AI-17-568). Examples of each goal from the Commission's resource planning decision criteria:

- reliability—7843.0500 subp. 3 A—ability to maintain or improve the adequacy and reliability of utility service;
- cost—7843.0500 subp. 3 B—keep the customers' bills and the utility's rates as low as practicable;
- risk—7843.0500 subp. 3 E—risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control; and
- impact—7843.0500 subp. 3 C—minimize adverse socioeconomic effects and adverse effects upon the environment.

C. DEMAND AND ENERGY FORECAST

1. Introduction

For this IRP, the Department neither reviewed the technical details of Xcel's forecast nor tested all the Company's previous or current statistical models. Instead, the Department examined the accuracy of Xcel's forecasting over the past 15 years. As described below, our review indicates that the Company's demand and energy forecasts have a systematic bias. Consequently, for this IRP, the Department adjusted Xcel's forecast to account for the bias and used the adjusted forecast to evaluate capacity expansion plans.

The Department conducted a similar analysis of Minnesota Power, a division of ALLETE, Inc.'s (MP) historical forecasting for MP's 2015 IRP (See the Department's March 4, 2016 *Reply Comments* in Docket No. E015/RP-15-690, pages 5 to 10). Table 2 below summarizes the relevant data for MP's demand forecast process. Note that the equivalent data for MP's energy forecast process is similar. In this case, MP's data can be used as a standard of comparison to gauge the quality of Xcel's forecasts. Generally speaking, a review of how well a forecast predicts usage over a prior period is a good indicator of the quality of the overall forecasting process.

In reviewing Table 2 the first thing to focus on is whether the data points tend to be:

- below zero—the demand forecast was too low[14];
- above zero—the demand forecast was too high[15]; or
- neither higher nor lower than forecasted.

[14] Actual demand was higher than forecasted.

[15] Actual demand was lower than forecasted.

Table 2: Percent Error in MP's Demand Forecast

Forecast Vintage	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
AFR 2000	0.9%	13.7%	-5.6%	-1.3%	-3.1%	-6.8%	-8.5%	-7.5%	-3.1%	23.6%	-2.2%	-1.6%	-2.8%	-0.2%
AFR 2001		5.2%	-0.5%	4.0%	1.8%	-2.5%	-4.6%	-3.8%	0.5%	28.0%	1.4%	2.4%	1.2%	2.9%
AFR 2002			-2.0%	5.0%	3.5%	-0.6%	-2.6%	-1.9%	2.3%	30.7%	2.4%	3.1%	1.4%	2.7%
AFR 2003				2.4%	-4.4%	-6.4%	-6.9%	-8.2%	-3.1%	24.6%	-2.9%	-1.7%	-2.2%	-1.7%
AFR 2004					0.0%	0.0%	-3.9%	-3.5%	3.7%	30.8%	1.7%	4.8%	4.1%	5.6%
AFR 2005						-5.0%	-6.9%	-6.3%	3.1%	30.7%	2.5%	3.3%	2.0%	4.4%
AFR 2006							-0.2%	-0.7%	4.5%	34.3%	5.9%	7.0%	6.0%	7.5%
AFR 2007								-2.4%	2.2%	31.4%	3.5%	4.8%	3.6%	5.2%
AFR 2008									2.5%	31.0%	3.2%	3.7%	2.4%	3.6%
AFR 2009										0.0%	-21.1%	-15.6%	-11.9%	-8.9%
AFR 2010											-0.1%	-1.4%	-2.6%	-1.5%
AFR 2011												-1.5%	-3.5%	-2.4%
AFR 2012													-3.7%	-3.0%
AFR 2013														-2.8%

For easy identification, the Department shaded cells in Table 2 that are negative. Review of Table 2 shows that 50 percent of the demand forecast data points[16] were above zero (too high), 48 percent were below zero (too low), and the rest were correct. Based upon this data, the Department concluded in MP's IRP that there was no evidence of systematic bias in MP's demand forecast processes. This means that MP's forecast process did not systematically over-forecast or under-forecast demand. Similar results were obtained when the Department reviewed MP's energy forecast process. This result is important because, while it is known that all forecasts are wrong in the sense that they will not be equal to the actual value, for the forecast to be useful it should be unbiased. Here, by unbiased, the Department means that the actual values are as likely to be above the forecast as they are likely to be below the forecast. If a forecast is unbiased, in the long run the average error should be approximately zero. If there is a systematic bias that results in over-forecasting or under-forecasting, the need for additional resources will be overstated or under-stated. The resulting risk is that a utility builds unnecessary resources or is unable to provide adequate resources to meet actual demand.

The second thing to note when reviewing Table 2 is the specific numbers that show the difference between the actual result and the forecast. About 71 percent of MP's data points (demand forecast process shown in Table 2) and 72 percent of MP's data points (energy forecast process —not shown here) were within a ±5 percent (high and low) forecast band. Based upon this data, the Department concluded that use of a ±5 percent was sufficient to capture a reasonable portion of the uncertainty inherent in MP's future demand requirements.

Given the valuable insights produced by the analysis of MP's forecast process the Department performed a similar analysis for Xcel. The purpose was the same, to check for evidence of systematic bias in Xcel's forecast process and also to determine the appropriate forecast bands to use for Xcel's IRP.

2. Data Analyzed

The Department began by reviewing the data provided by Xcel in response to Sierra Club Information Requests (IR) Nos. 42 (historic actual demand and energy requirements) and 45 (past forecasts). However, Xcel's response to the Sierra Club provided multiple answers regarding measures of historic energy requirements. Therefore, Department IR Nos. 62 and 63 requested Xcel explain which measure of historic energy and demand requirements was comparable to the forecasts. Xcel's response provided data on historic energy and demand requirements that was comparable to the past forecasts.

After reviewing the data, the Department determined that additional data was required on historic actuals and past forecasts. In addition, the Department noted what appeared to be potential discrepancies in the data provided by Xcel. Therefore, through Department IR Nos. 64 to 68 the Department requested additional explanations, data on past actuals back to 2004, and past forecasts back to 2003. This additional data enabled the Department to review the forecast process for a duration approximately equivalent to an IRP planning period.

[16] Each year of a 15-year forecast was considered a separate data point for purposes of the analysis. The forecasts included were the Annual Forecast Reports (AFR) for years 2000 to 2013 and the actual demand and energy for 2000 to 2013. Thus, MP's forecast "AFR 2000" had 14 separate data points, one each for the years 2000 to 2013 while the forecast "AFR 2012" had only two separate data points, 2012 and 2013.

Using Xcel's responses, the Department compared actual energy sales (Department IR No. 64) and uninterrupted peak demand (Department IR No. 65) for the years 2004 to 2018 to Xcel's demand and energy forecasts (Department IR No. 66) from August 2003 to July 2018.[17]

3. Demand Forecast Process

The Department's first step in analyzing Xcel's demand forecast process was calculating the difference between forecasted demand and actual peak demand. The results of this calculation are shown below in Tables 3a and 3b. As with Table 2 showing data from MP, in Tables 3a and 3b a positive number indicates the forecast turned out to be too high and a negative number indicates that the forecast turned out to be too low. For easy identification, the Department shaded the cells in Tables 3a and 3b that are negative.

[17] Xcel produces multiple forecasts in most years thus there were a total of 31 different forecasts provided by Xcel.

Table 3a: Xcel's Demand Forecast Error, Pre-October 2008 (MW)

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Forecast Vintage	Aug-03	507	251	(313)	294	1,266	1,523	1,195	889	1,223	1,337	2,193	2,599	2,396	3,015	2,770
	Jun-04	470	200	(375)	187	1,144	1,380	1,032	709	1,034	1,131	1,975	2,371	2,168	2,781	2,546
	Feb-05		65	(458)	126	1,108	1,366	1,034	718	1,053	1,158	2,009	2,428	2,252	2,885	2,669
	Mar-06			(524)	111	1,106	1,431	1,123	841	1,186	1,333	2,209	2,646	2,465	3,148	2,944
	Sep-06			(498)	150	1,121	1,418	1,093	810	1,155	1,303	2,179	2,616	2,435	3,118	2,913
	Mar-07				104	1,100	1,337	1,028	727	1,068	1,160	2,014	2,406	2,210	2,807	2,595
	Oct-07				(46)	1,043	1,272	929	567	835	890	1,683	2,018	1,746	2,298	2,017
	Mar-08					977	1,241	862	469	747	817	1,608	1,952	1,686	2,245	1,944

Table 3b: Xcel's Demand Forecast Error, October 2008 to Present (MW)

Forecast Vintage	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Oct-08					873	1,053	612	196	451	504	1,279	1,606	1,322	1,866	1,550
Apr-09						790	280	(167)	31	38	762	1,044	725	1,238	882
Oct-09						6	149	(232)	29	26	744	1,009	672	1,165	796
Apr-10							16	(293)	31	140	973	1,330	1,079	1,653	1,370
Jul-10							55	(266)	41	99	891	1,205	912	1,442	1,114
Apr-11								(483)	(230)	(231)	567	909	629	1,179	862
Sep-11								169	(262)	(311)	453	776	487	1,027	716
Mar-12									(508)	(510)	241	553	261	809	504
Jul-12									3	(309)	432	749	438	971	641
Mar-13										(350)	355	643	324	855	529
Jul-13										(228)	507	813	494	1,006	654
Sep-13										(352)	364	620	313	854	531
Mar-14											440	703	394	918	587
Aug-14											-	680	407	932	604
Mar-15												622	357	900	558
Jul-15												570	325	857	515
Mar-16													140	689	326
Aug-16													116	636	266
Nov-16														633	262
Mar-17														641	254
Jul-17														590	260
Mar-18															112
Jul-18															181

When considering all forecasts, about 91 percent of the data points are positive and only nine percent are negative. When considering only the forecasts from October 2008[18] to present, about 88 percent of the data points are positive and only 12 percent are negative. Based upon this data the Department concludes that there is evidence of a systematic bias in Xcel's demand forecast process. In other words, the Company's demand forecast is consistently too high.

The Department's second step was to determine the size of the error (in MW) resulting from the demand forecast process. Due to the change in Xcel's forecast process, the Department focused on the error for the demand forecasts starting in October 2008; the error was calculated for the first forecast year, the second forecast year, and so on. The result was that one year out the average error is about 175 MW, which is small considering the size of Xcel's system. Three years out Xcel's average error is about 325 MW, about the size of a large combustion turbine or the initial accredited capacity expected from about 650 MW of solar. By five years out Xcel's average error is about 625 MW or two large CT units and by eight years out the average error is about 1,100 MW. Thus, the size of the error consistently grows the further into the future the calculations are taken. The Department considered this degree of error when determining the forecast bands used by the Department in its modeling, as explained below.

The Department's third step was to calculate the percent error in order to help determine the appropriate forecast adjustment and forecast bands. The result of this calculation is shown below in Tables 4a and 4b. As above, the focus is on the forecast vintages of October 2008 to July 2018 due to the change in forecast process. Again, the percent error was calculated for the first forecast year, the second forecast year, and so on. The result was that one year out Xcel's average error equals 2.1 percent. Three years out Xcel's average error is about 3.6 percent. By five years out Xcel's average error is 7.1 percent. By seven years out Xcel's average error is 11 percent. This data indicates that the ± five percent forecast bands previously used by the Department in MP's case are not large enough to address the errors present in Xcel's demand forecast process once the forecast goes beyond about five years.

[18] The importance of October 2008 forecast was explained by Xcel in response to Department IR No. 66 as:

> The Company notes that there are structural drivers – both relative to our forecasting methods and to our external operating environment – that may contribute to variation across the fifteen years of forecast vintages. For example, prior to October 2008, we did not reduce our forecasts for demand side management and energy efficiency effects. There can also be local economic conditions that drive unforeseen changes in demand and load between forecast vintages, such as the effect of recessions, or individual large customers exiting our service area.

Thus, in October 2008 Xcel changed its forecast process.

Table 4a: Xcel's Demand Forecast Error, Pre-October 2008 (percent)

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Forecast Vintage	**Aug-03**	5.9%	2.8%	-3.2%	3.1%	14.6%	17.7%	13.1%	9.2%	12.9%	14.0%	24.8%	30.2%	26.6%	35.3%	31.0%
	Jun-04	5.4%	2.2%	-3.8%	2.0%	13.2%	16.0%	11.3%	7.4%	10.9%	11.9%	22.3%	27.5%	24.1%	32.5%	28.5%
	Feb-05		0.7%	-4.6%	1.3%	12.7%	15.9%	11.3%	7.5%	11.1%	12.2%	22.7%	28.2%	25.0%	33.8%	29.8%
	Mar-06			-5.3%	1.2%	12.7%	16.6%	12.3%	8.7%	12.5%	14.0%	25.0%	30.7%	27.4%	36.8%	32.9%
	Sep-06			-5.1%	1.6%	12.9%	16.5%	12.0%	8.4%	12.2%	13.7%	24.6%	30.3%	27.0%	36.5%	32.6%
	Mar-07				1.1%	12.7%	15.5%	11.3%	7.6%	11.3%	12.2%	22.8%	27.9%	24.5%	32.8%	29.0%
	Oct-07				-0.5%	12.0%	14.8%	10.2%	5.9%	8.8%	9.3%	19.0%	23.4%	19.4%	26.9%	22.5%
	Mar-08					11.2%	14.4%	9.4%	4.9%	7.9%	8.6%	18.2%	22.6%	18.7%	26.3%	21.7%

Table 4b: Xcel's Demand Forecast Error, October 2008 to Present (percent)

Forecast Vintage	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Oct-08					10.0%	12.2%	6.7%	2.0%	4.8%	5.3%	14.5%	18.6%	14.7%	21.8%	17.3%
Apr-09						9.2%	3.1%	-1.7%	0.3%	0.4%	8.6%	12.1%	8.1%	14.5%	9.9%
Oct-09						0.1%	1.6%	-2.4%	0.3%	0.3%	8.4%	11.7%	7.5%	13.6%	8.9%
Apr-10							0.2%	-3.0%	0.3%	1.5%	11.0%	15.4%	12.0%	19.3%	15.3%
Jul-10							0.6%	-2.8%	0.4%	1.0%	10.1%	14.0%	10.1%	16.9%	12.4%
Apr-11								-5.0%	-2.4%	-2.4%	6.4%	10.5%	7.0%	13.8%	9.6%
Sep-11								1.8%	-2.8%	-3.3%	5.1%	9.0%	5.4%	12.0%	8.0%
Mar-12									-5.4%	-5.4%	2.7%	6.4%	2.9%	9.5%	5.6%
Jul-12									0.0%	-3.2%	4.9%	8.7%	4.9%	11.4%	7.2%
Mar-13										-3.7%	4.0%	7.5%	3.6%	10.0%	5.9%
Jul-13										-2.4%	5.7%	9.4%	5.5%	11.8%	7.3%
Sep-13										-3.7%	4.1%	7.2%	3.5%	10.0%	5.9%
Mar-14											5.0%	8.2%	4.4%	10.7%	6.6%
Aug-14											0.0%	7.9%	4.5%	10.9%	6.7%
Mar-15												7.2%	4.0%	10.5%	6.2%
Jul-15												6.6%	3.6%	10.0%	5.8%
Mar-16													1.5%	8.1%	3.6%
Aug-16													1.3%	7.4%	3.0%
Nov-16														7.4%	2.9%
Mar-17														7.5%	2.8%
Jul-17														6.9%	2.9%
Mar-18															1.3%
Jul-18															2.0%

To determine a forecast adjustment the Department compared the average error from Xcel's forecasts performed in October 2008 to July 2018 and determined a forecast adjustment considering Xcel's average error. The Department's demand forecast adjustment is shown in Table 5 below.

Table 5: Demand Forecast Adjustment (percent)

Forecast Year	Average Forecast Error	Department Forecast Adjustment	Difference
1	2.1%	2.0%	-0.1%
2	2.8%	2.0%	-0.8%
3	3.6%	4.0%	0.4%
4	4.9%	4.0%	-0.9%
5	7.1%	8.0%	0.9%
6	8.7%	8.0%	-0.7%
7	11.0%	12.0%	1.0%
8	12.6%	12.0%	-0.6%
9	14.1%	12.0%	-2.1%
10	13.5%	12.0%	-1.5%
11	17.3%	12.0%	-5.3%
12		12.0%	
13		12.0%	
14		12.0%	
15		12.0%	

Considering the poor quality of Xcel's forecasts, the Department did not want to imply that finely tuned adjustments were possible. Thus, the Department constructed the forecast adjustments using two criteria; maintaining any adjustment for two years and adjusting Xcel's forecast using two percentage point increments. For informational purposes, Table 5 above shows how the Department's forecast adjustment deviated from each year's average forecast error.

To determine forecast bands, the Department assumed that Company's forecast represents a reasonable high end of a forecast band. The Company's base forecast was used as the high contingency to create a tie between the forecast used by the Department and the forecast used by Xcel. For the low forecast band, the Department assumed the low forecast band used in the past, minus 5 percent, would remain sufficient.

As noted above Xcel changed its forecast process in October 2008. Thus, the Department's fourth step was to compare the two forecast processes. The Department compared the demand forecast errors for the two processes 1 year out, 2 years out, 3 years out, and so on. The Department based this comparison on the average error for Xcel's demand forecasts before October 2008 compared to Xcel's demand forecasts prepared in October 2008 and after, as shown in Tables 5a and 5b above. The Department's comparison showed that the original process had smaller errors (by about 0.4 percent) 1 year out. However, for years 2 through 9 the new forecast process had smaller errors (between 2 and 5 percentage points). In the last years (10 and 11)[19] the new forecast process had smaller errors (by about 9 percentage points) but there are very few data points to compare, rendering the comparison somewhat suspect. However, the new process did not eliminate the forecast bias which is the over-riding problem.

4. *Energy Forecast Process*

The Department repeated the analysis of Xcel's demand forecast process for Xcel's energy forecast process. Although the Department found that the Company's energy forecasting was less systematically biased than the demand forecasts, Xcel's energy forecast process is still systematically biased. Note that not all energy forecast vintages forecasted the same years as the equivalent demand forecast vintages and, as a result, the tables below are slightly different than the equivalent demand forecast tables. For example, the July 2018 forecast forecasted peak demand in 2018 but did not forecast energy in 2018.

The Department began the analysis of Xcel's past energy forecasts by calculating the difference between the forecasted and actual energy in GWh. The GWh error was then converted into a percent error. The results of this calculation are shown below in Tables 6a and 6b. In Tables 6a and 6b above, a positive number indicates the energy forecast turned out to be too high and a negative number indicates that the energy forecast turned out to be too low. For easy identification, the Department shaded cells in Tables 6a and 6b that are negative.

[19] Year 11 is the final year because the forecasts start in 2008 and the last year of actuals is 2018.

Table 6a: Xcel's Energy Forecast Error, Pre-October 2008 (Percent)

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Forecast Vintage	Aug-2003	6.1%	3.3%	2.8%	1.4%	4.8%	11.2%	10.6%	13.1%	16.8%	20.3%	22.8%	27.1%	28.1%	33.2%	31.3%
	Jun-2004	4.8%	2.2%	1.7%	0.2%	3.3%	9.1%	8.2%	10.4%	14.1%	17.1%	19.5%	23.6%	24.7%	29.6%	28.1%
	Feb-2005		2.2%	1.2%	-0.5%	2.7%	8.4%	7.4%	9.3%	12.7%	15.3%	17.4%	21.2%	22.2%	26.7%	24.9%
	Mar-2006			2.6%	1.3%	5.3%	12.2%	11.7%	14.4%	18.2%	21.9%	24.8%	29.6%	30.9%	36.6%	35.4%
	Sep-2006			3.7%	1.8%	5.3%	11.7%	11.0%	13.7%	17.4%	21.2%	24.1%	28.9%	30.1%	35.9%	34.7%
	Mar-2007				0.0%	2.4%	8.0%	6.7%	8.4%	11.2%	13.7%	15.2%	18.4%	18.5%	22.7%	20.7%
	Oct-2007				-0.1%	2.6%	8.1%	6.8%	8.4%	11.2%	13.6%	15.0%	18.1%	18.2%	22.1%	19.8%
	Mar-2008					1.3%	6.8%	4.8%	5.9%	8.5%	10.8%	12.1%	15.1%	15.0%	18.7%	16.3%

Table 6b: Xcel's Energy Forecast Error, October 2008 to Present (Percent)

Forecast Vintage	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Oct-2008					0.1%	4.5%	2.3%	3.4%	5.7%	7.7%	8.8%	11.5%	11.3%	14.7%	12.3%
Apr-2009						4.1%	1.0%	2.2%	4.6%	6.7%	8.0%	10.8%	10.7%	14.2%	12.0%
Oct-2009						1.7%	-1.4%	0.5%	3.4%	5.8%	7.1%	9.6%	9.4%	12.9%	10.8%
Apr-2010							-1.7%	-0.2%	2.6%	4.6%	6.0%	8.5%	8.5%	11.7%	9.4%
Jul-2010							-1.5%	-0.7%	1.9%	3.8%	5.3%	7.9%	8.0%	11.1%	8.8%
Apr-2011								-0.7%	1.6%	2.6%	3.9%	6.7%	6.7%	9.8%	7.3%
Sep-2011								-1.1%	0.2%	0.9%	1.9%	4.4%	4.2%	7.1%	4.7%
Mar-2012									-0.8%	-0.8%	-0.3%	1.8%	1.6%	4.5%	2.0%
Jul-2012									-1.2%	-1.7%	-1.3%	0.7%	0.5%	3.2%	0.8%
Mar-2013										-1.5%	-1.4%	0.5%	0.2%	2.8%	0.4%
Jul-2013										-1.5%	-1.4%	0.5%	0.2%	2.8%	0.4%
Sep-2013										-1.5%	-1.8%	-0.2%	-0.6%	1.9%	-0.5%
Mar-2014											-1.3%	0.3%	-0.4%	2.2%	-0.3%
Aug-2014											-0.6%	1.9%	1.8%	4.6%	2.2%
Mar-2015												2.4%	2.5%	5.2%	2.7%
Jul-2015												1.5%	1.5%	4.2%	1.8%
Mar-2016													0.7%	3.2%	0.2%
Aug-2016														1.8%	-1.4%
Nov-2016														1.7%	-1.4%
Mar-2017														1.7%	-1.4%
Jul-2017															-1.5%
Mar-2018															-2.7%
Jul-2018															

When considering all of Xcel's energy forecasts, about 86 percent of the data points are positive and only 14 percent are negative. When considering only Xcel's energy forecasts from October 2008 to present, about 75 percent of the data points are positive and 25 percent are negative. Based upon this data, while not quite as clear as with the demand forecast process, the Department concluded that, once again, there is evidence of a systematic bias in Xcel's energy forecast process. The Company's energy forecast is consistently too high.

While not shown, the size of the energy forecast error may also be of interest. The Department focused on the energy forecast error for the energy forecasts from October 2008 to July 2018; the error was calculated for the first forecast year, the second forecast year, and so on. The result of the calculation was that two years out the Xcel's average energy forecast error is about 65 GWh, which is not much considering the size of Xcel's system.[20] Four years out Xcel's average energy forecast error is about 1,100 GWh. By six years out Xcel's average energy forecast error is about 2,150 GWh and at eight years out Xcel's average energy forecast error is 4,200 GWh or equivalent to the energy output from nearly 1,000 MW of wind or 2,500 MW of solar. As with the demand forecast, the size of the error consistently grows the further into the future the calculations are taken. The Department explains its methodology for choosing energy forecast bands below.

As with the analysis of the demand forecast process, the Department focused on the forecast vintages from October 2008 to present due to Xcel's change in forecast process. Again, the Department calculated the percent error for the first forecast year, the second forecast year, and so on. The result was that two years out Xcel's average energy forecast error equals 0.1 percent, which is essentially no different than zero. Four years out Xcel's average energy forecast error is about 2.4 percent, somewhat less than the equivalent figure for the demand forecast. By six years out Xcel's average error is 4.9 percent, equal to the Department's widest (±5 percent) forecast band used in the past. By eight years out Xcel's average error is 9.5 percent.

To determine a forecast adjustment the Department reviewed the average error from forecasts performed between October 2008 and July 2018 and determined an adjustment using that error. This is shown in Table 7 below.

[20] Note that, for comparison, a 100 MW wind unit at a 50 percent capacity factor or a 250 MW solar unit at a 20 percent capacity factor would each produce about 440 GWh annually.

Table 7: Energy Forecast Adjustment (percent)

Forecast Year	Average Forecast Error	Forecast Adjustment	Difference
1	-0.1%	0.0%	0.1%
2	0.1%	0.0%	-0.1%
3	1.4%	2.0%	0.6%
4	2.4%	2.0%	-0.4%
5	3.7%	4.0%	0.3%
6	4.9%	4.0%	-0.9%
7	7.3%	8.0%	0.7%
8	9.5%	8.0%	-1.5%
9	11.3%	10.0%	-1.3%
10	12.5%	10.0%	-2.5%
11	12.3%	10.0%	-2.3%
12		10.0%	
13		10.0%	
14		10.0%	
15		10.0%	

As noted previously, the Department used two-year intervals and two percentage point increments to calculate the forecast adjustment. To determine forecast bands, the Department assumed that Company's forecast represents a reasonable high end of a forecast band. The Company's base forecast was used as the high contingency to create a tie between the forecast used by the Department and the forecast used by Xcel. For the low forecast band, the Department assumed the low forecast band used in the past, minus five percent, would remain sufficient.

Finally, as noted above, the Company's forecast process changed in October 2008. Thus, the Department compared the energy forecast errors for the two processes—one year out, two years out, three years out, and so on. This was done based on the average error for Xcel's demand forecasts before October 2008 compared to Xcel's demand forecasts prepared in October 2008 and after. The result of the comparison was that the new process appeared to have lesser errors. However, the new process did not eliminate the forecast bias which is the over-riding problem.

5. Conclusion

The main conclusion from our analysis is that Xcel's demand and energy forecast processes are systematically biased; they produce forecasts that are too high much more often than they produce forecasts that are too low. Again, the Department notes, if there is a systematic bias that results in over-forecasting, the need for additional resources will be overstated. The resulting risk is that Xcel builds unnecessary resources resulting in potential cost-related risks to Xcel's customers. Clearly it would be preferable to have forecasts that appear to be unbiased, however such data is not available. To account for the persistent bias while allowing the remaining analysis to move forward, the base forecast was adjusted by the amounts shown in the Tables above. The

Department used Xcel's base forecast as the high end of the reasonable forecast band to create a connection between the Department's and Xcel's forecast used in modeling. The low end of a reasonable forecast is about five percent below the Department's base forecast.

To address the persistent bias in Xcel's forecast process going forward, the Department recommends that the Commission require Xcel to file and use a forecast from an independent consultant in any future regulatory proceedings. This requirement will enable Xcel's proceedings to continue normally while the Company attempts to audit and identify the flaws in their current forecast process. The use of an independently prepared forecast should continue until such time as Xcel can demonstrate in a separate proceeding that the Company has identified the source(s) of the bias in Company prepared forecasts and has identified, explained, and taken steps that can reasonably be expected to address the identified issues.

D. NATURAL GAS TRANSPORTATION RISKS

For this IRP the Department further explored the Company's exposure to risks related to natural gas transportation. This review was triggered by the increasing use of natural gas-fueled capacity on the Company's system and events during recent winters. Note that risks related to natural gas pricing are explored in the Department's CEM analysis elsewhere in these comments. The focus of this discussion is on the reliability of natural gas delivery to the relevant power plants.

In Department IRs Nos. 12 and 40 the Department requested Xcel provide certain data for each power plant that consumed natural gas during 2016 to 2018. Xcel's response provided data regarding several power plants, some of which use natural gas as a secondary fuel.[21] In addition, several of the units were reported by Xcel as having fuel oil as back-up.[22] These units and the Company's now retired units were removed from further analysis.

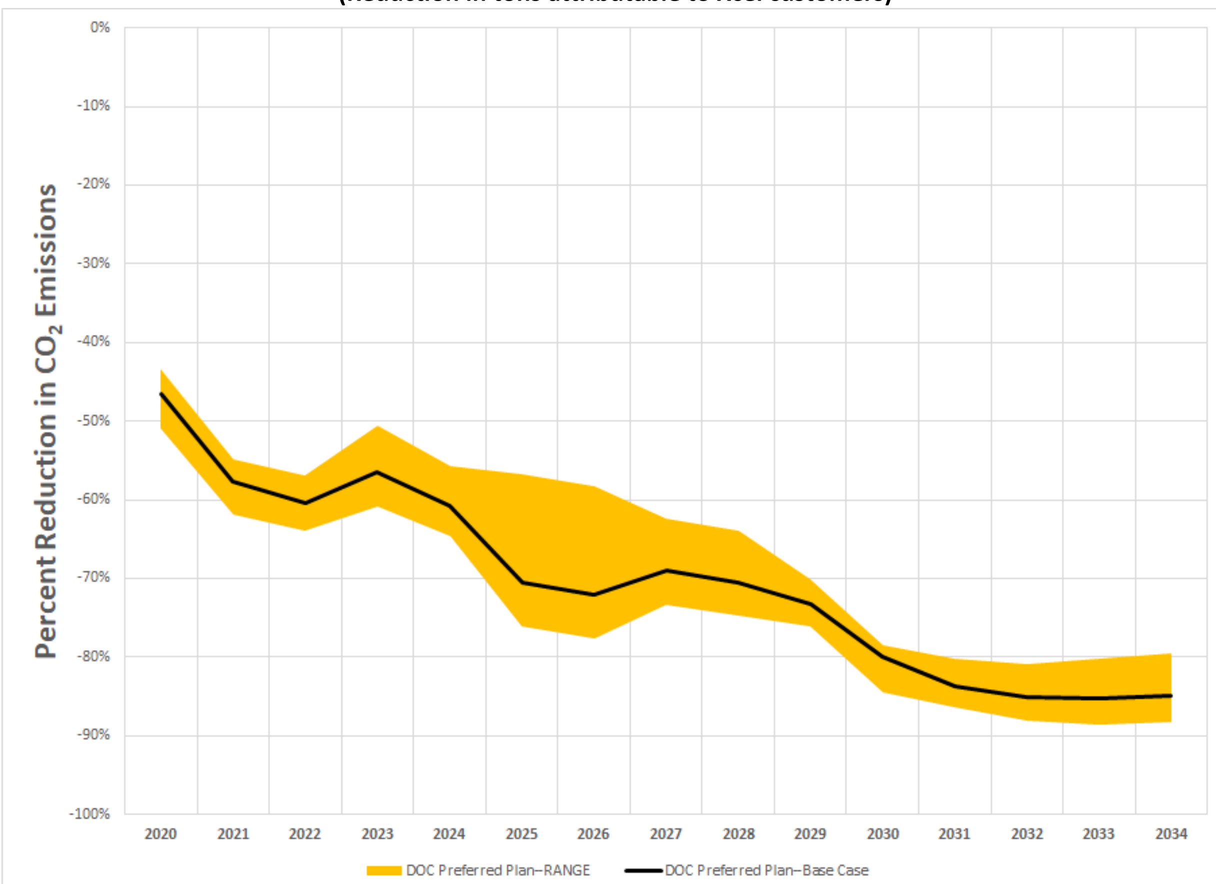
The remaining units which use natural gas with no fuel oil back up are forecasted to provide Xcel between 2.9 GW and 3.4 GW of accredited capacity during the years 2020 to 2030. While some units are scheduled to retire or have PPAs that expire, Xcel also expects the addition of a natural gas CC unit at the Sherco site.[23] Overall, about 60 to 67 percent of the expected natural gas capacity comes from six CC units[24] and a further 18 to 20 percent from four large CT units.[25] With the exception of the Blue Lake plant, the units all take firm service from an interstate pipeline (Northern Natural Gas) and, where applicable, firm transportation service from the local distribution company (LDC).

Regarding Blue Lake, Xcel's response to Department IR No. 40 stated:

> Blue Lake takes Firm Transportation service from the LDC system, because it was required to commit to such service to reimburse the LDC for constructing the supply pipeline serving the plant. Blue Lake takes interruptible service from the

[21] Note that Xcel did not provide data regarding the Cottage Grove CC unit since under the PPA the seller (LS Power) is responsible for providing its own gas supply and transportation.
[22] The units with fuel oil are Angus C. Anson units 2 and 3, Wheaton units 1 to 6, French Island units 3 and 4, Inver Hills units 1 to 6, Blue Lake units 1 to 4, Mankato (first PPA only), and Cannon Falls units 1 and 2.
[23] See Minnesota Session Laws, 2017 Regular Session, Chapter 5.
[24] Namely Black Dog, High Bridge, Riverside, Cottage Grove, Mankato (second PPA), and the presumed Sherburne County addition.
[25] Namely Anson unit 4, Blue Lake units 7 and 8, and Black Dog unit 6.

Figure 11: Greenhouse Gas Reduction
(Reduction in tons attributable to Xcel customers)



III. DEPARTMENT RECOMMENDATIONS

Regarding forecasting, the Department recommends that the Commission order Xcel to file and use a forecast from an independent consultant in any future regulatory proceedings. Additionally, the use of an independently derived forecast should continue until such time as Xcel can demonstrate in a separate proceeding that the Company has identified the source(s) of the bias in Company prepared forecasts and has identified, explained, and taken steps that can reasonably be expected to address the identified issues.

Regarding the proposed Sherco CC unit, the Department recommends the Commission not make a determination regarding reasonable and prudently incurred costs in this proceeding. Since Xcel has not requested approval of a revision of the Sherco CC unit included in the last IRP, the Department also recommends the Commission not approve any revision to the Sherco CC unit included in E002/RP-15-21.

COMMERCE DEPARTMENT

October 15, 2021

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, Minnesota 55101-2147

RE: **Supplemental Comments of the Staff of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E002/RP-19-368

Dear Mr. Seuffert:

Attached are the Supplemental Comments of the Staff of the Minnesota Department of Commerce, Division of Energy Resources (Department Staff), in the following matter:

2020-2034 Upper Midwest Integrated Resource Plan.

The Petition was filed on July 1, 2019 (as supplemented on June 30, 2020) by:

Christopher B. Clark
President
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401

Department Staff recommends that the Minnesota Public Utilities Commission (Commission) **approve the petition with modifications**. Department Staff's team of Danielle Winner, Matthew Landi, Sachin Shah and myself are available to answer any questions that the Commission may have.

Sincerely,

/s/ STEVE RAKOW
Analyst Coordinator

SR/ar
Attachment

Before the Minnesota Public Utilities Commission

Supplemental Comments of the Staff of the Minnesota Department of Commerce Division of Energy Resources

Docket No. E002/RP-19-368

I. INTRODUCTION

A. DOCKET HISTORY—FIRST ROUND

On July 1, 2019 Northern States Power Company, doing business as Xcel Energy (Xcel or the Company) filed the Company's *2020-2034 Upper Midwest Integrated Resource Plan* (Petition). The Petition was filed in compliance with the Minnesota Public Utilities Commission's (Commission) January 30, 2019 *Order Extending Deadline for Filing Next Resource Plan* and January 11, 2017 *Order Approving Plan with Modifications and Establishing Requirements for Future Resource Plan Filings* in Docket No. E002/RP-15-21.

On July 3, 2019 the Commission issued its *Notice of Comment Period* which stated that comments on the Petition are due November 8, 2019 and January 8, 2020 and that comments on completeness were due August 1, 2019.

On July 18, 2019 the Commission issued its *Order Requiring Bill Insert and Referring Matter to OAH for Public Meeting* (Meeting Order). The Meeting Order established a process for holding public meetings to ensure that Xcel's customers have an opportunity to participate in the IRP process.

On July 25, 2019 the Minnesota Department of Commerce, Division of Energy Resources (Department) filed a letter recommending that the Commission not undertake a completeness review.

In response to the Meeting Order, on July 30, 2019 the Minnesota Office of Administrative Hearings (OAH) issued OAH's *Scheduling Order*, establishing October 21, 23, 28, and 30 as dates for public meetings.

On July 31, 2019 the city of Minneapolis filed a letter on completeness.

On October 8, 2019 Xcel filed a letter indicating that the Company could:

- provide updated Strategist modeling in a new filing by December 6, 2019;
- participate with other utilities in a planning meeting to cover the new capacity expansion modeling (CEM) tool (Encompass), along with a variety of topics; and
- provide a supplemental filing in the April 2020 timeframe using EnCompass.

On or about October 15, 2019 the following organizations and coalitions filed comments on modifying the comment deadlines:

- Sierra Club, Vote Solar, and the Institute for Local Self-Reliance;
- Clean Energy Organizations;[1]
- Citizens Utility Board of Minnesota;
- Xcel Large Industrials (XLI);[2]

On November 12, 2019 the Commission issued its *Order Suspending Procedural Schedule and Requiring Additional Filings* (Supplemental Order). The Supplemental Order:

- suspended the procedural schedule;
- required Xcel to file certain supplemental information; and
- delegated to the Executive Secretary the establishment of a new procedural schedule—but stated that Xcel's supplement could be filed no later than July 1, 2020.

On December 18, 2019 the OAH filed its *Report Summarizing Public Meetings* which summarized the public comments obtained at the October public meetings regarding the Petition.

B. DOCKET HISTORY—SECOND ROUND

On December 6, 2019 the Commission issued a notice indicating that:

- Xcel must file a supplement by April 1, 2020;
- comments are due August 3, 2020; and
- reply comments are due October 2, 2020.

On February 12, 2020 the Minnesota Sustainable Growth Coalition (MSG) filed comments on behalf of MSG's non-utility members regarding Xcel's proposed plan.[3]

On March 6, 2020 Xcel filed the Company's *Extension Request*, requesting an extension for the supplemental filing to May 15, 2020 in light of the need to conduct a substantial update of the Strategist modeling, and to implement the EnCompass model, including development of more granular modeling inputs for hourly analysis.

On March 11, 2020 the Commission issued its *Notice Approving Extension Request and Extending Comment Periods* establishing a new deadline for Xcel's supplement and for filing initial comments and reply comments.

[1] This coalition consists of Clean Grid Alliance, Fresh Energy, Minnesota Center for Environmental Advocacy, and the Union of Concerned Scientists.

[2] This coalition consists of Covia Holdings Corporation; Flint Hills Resources Pine Bend, LLC; Gerdau Ameristeel US Inc.; Marathon Petroleum Corporation; and USG Interiors, Inc.

[3] MSG's non-utility members come from the private, public, and non-profit sectors.

On March 13, 2020 International Brotherhood of Electrical Workers locals 23, 160, and 949 filed comments regarding Xcel's proposed plan.

On April 10, 2020 Xcel filed the Company's *Extension Request*, requesting a second extension for the supplemental filing to June 30, 2020 in light of the ongoing COVID-19 public health emergency.

On April 16, 2020 the Commission issued its *Second Notice Approving Extension Request and Extending Comment Periods* stating that:

- the deadline for Xcel's supplement is June 30, 2020;
- the deadline for filing initial comments is October 30, 2020; and
- the deadline for filing reply comments is January 15, 2021.

On June 30, 2020 Xcel filed the Company's *Supplement to the Petition* (Supplement).

On September 15, 2020, at the request of the Department, the Commission established January 15, 2021 as the due date for comments and March 15, 2021 as the due date for reply comments.

On December 23, 2020 the Department issued Global Energy & Water Consulting, LLC's (Global) *Independent Investigation of Cost Overruns and Cost Estimates for Xcel Energy's Monticello and Prairie Island Nuclear Power Plants* (Report). The Department retained Global to prepare the Report in compliance with the Commission's March 26, 2019 *Order Authorizing Commissioner of Commerce to Seek Funding for Specialized Technical Professional Services Under Minn. Stat. § 216B.62 Subd. 8* in Docket Nos. E002/RP-15-21 and E002/GR-15-826:

> The Commission authorizes the Commissioner of the Department of Commerce to seek authority from the Commissioner of Management and Budget to incur costs for specialized technical professional investigative services under Minn. Stat. § 216B.62, Subd. 8, to continue investigating the causes of cost increases related to Xcel's Prairie Island and Monticello nuclear facilities and to assist the Department in Xcel's upcoming integrated resource plan and rate case proceedings.

On December 28, 2020, at the Department's request, the Commission established February 11, 2021 as the due date for comments and April 12, 2021 as the due date for reply comments.

In January and February, 2021, comments were filed by the Prairie Island Indian Community, a federally recognized Indian tribe; Goodhue County Board of Commissioners; Board of Wright County Commissioners; St. Paul Area Chamber; MSG on behalf of MSG's non-utility members; Northern Natural Gas; and other organizations.

On February 10 and 11, 2021 the following organizations filed comments:

1. Center of the American Experiment;
2. Citizens Utility Board of Minnesota;
3. City of Becker;
4. City of Minneapolis;
5. City of Monticello;
6. Clean Energy Economy Minnesota;
7. Coalition of Utility Cities;[4]
8. Deputy Commissioner of the Department (Department Deputy);
9. Staff of the Department (Department Staff);
10. CEO;
11. Fresh Energy, Community Stabilization Project, Green & Healthy Homes Initiative, Inquilinxs Unidxs Por Justicia, Minnesota Housing Partnership, National Housing Trust, and Natural Resources Defense Council (collectively, EEFA Partners);
12. Laborers' International Union of North America Minnesota and North Dakota;
13. Monticello Industrial & Economic Development Committee;
14. Sierra Club;
15. St. Paul 350;
16. Vote Solar, Institute for Local Self Reliance, Cooperative Energy Futures, and the Environmental Law and Policy Center (collectively, DSP); and
17. XLI.

Xcel's reply comment proposed a revised 2020-2034 IRP, referred to as the "Alternate Plan." According to the Company, the main changes in the Alternate Plan as compared to its previously proposed IRP include:

- Elimination of a natural gas-fired combined cycle facility at the Sherco Generating Station (Sherco);
- Reutilization of interconnections at the retired Sherco and Allen S. King (King) coal sites to enable significant solar and wind additions, as well as hydrogen-capable combustion turbine (CT) resources; and
- Beginning a process to shift the Company's current emergency system restoration (black start) plans from the current centralized restoration approach to a zonal restoration approach

Numerous members of the public filed comments throughout this proceeding.

[4] The Coalition of Utility Cities is an organization of eight member cities that host Minnesota's largest power plants.

C. DOCKET HISTORY—THIRD ROUND

On June 30, 2021 the Commission filed its *Notice of Supplemental Comment Period* (Notice). The Notice stated that the following topics are open for comment:

1. Should the Commission approve, modify, or reject Xcel Energy's Alternate Plan, as described in the Company's June 25, 2021 Reply Comments?
2. If the Commission modifies the Alternate Plan, what modifications should the Commission make?
3. Should the Commission adopt a proposed alternative plan under Minnesota Rules 7843.0300 subp. 11? If so, provide a narrative with quantitative analysis supporting how the proposed changes are in the public interest, considering the factors listed in Minnesota Rules 7843.0500, subp. 3.
4. What resource acquisition process(es) should Xcel use to implement the approved resource plan?
5. When should Xcel file its next IRP?
6. Are there other issues or concerns related to this matter?

Below are Department Staff's supplemental comments regarding Xcel's proposed alternate plan and the issues specified by the Notice.

D. XCEL'S ALTERNATE PLAN

Xcel's rely comments describe the Company's alternate plan as follows:

- Regarding the baseload unit retirement schedule:
  - retire King in 2028;
  - retire Sherco Unit 3 in 2030;
  - operate the Monticello Nuclear Generating Plant (Monticello) through 2040;
    - Action plan: "We plan to initiate a Certificate of Need (CN) proceeding in Minnesota in the next several months."[5]
  - Operate both Prairie Island Nuclear Generating Plant (Prairie Island) units at least through the end of their current licenses—Prairie Island unit 1 to 2033 and Prairie Island unit 2 to 2034.
    - Action plan: "If a decision is made to extend the Prairie Island license, we would file a petition seeking a Certificate of Need in Minnesota within the Five-Year Action Plan window."
- Regarding addition of new solar capacity:
  - add approximately 3,150 MW of utility-scale solar by 2034; and
  - accommodate 575 MW of distributed solar by 2034.

[5] The petition has since been filed in Docket No. E002/CN-21-668.

        - Action plan: "we have proposed significant amounts of solar additions through a gen-tie line reutilizing the interconnection at the retired Sherco and King coal sites ... These additions start in 2024 with the retirement of Sherco Unit 2 and thus our development activities and associated regulatory proceedings will proceed in the near-term."
- Regarding addition of new wind capacity:
    - add approximately 2,650 MW of wind by 2034.
        - Action plan: "wind additions do not begin until 2028, procurement activities and potentially the regulatory proceedings for some additions could fall within the five-year plan."
- Regarding existing additional infrastructure:
    - add a double-circuit 140-mile 345 kV gen-tie line from Sherco to Lyon County to connect solar, wind, and firm dispatchable resources to the Sherco interconnection; and
    - add a single-circuit 15-mile 345 kV gen-tie line from King into Wisconsin to connect solar to the King interconnection.
        - Action plan: "We would start these efforts, including the associated regulatory proceedings, within the five-year plan window."
- Regarding new natural gas capacity:
    - do not add any new combined-cycle resources; and
    - add approximately 2,900 MW of firm, dispatchable capacity resources by 2034.
        - Action plan: "[the plan] includes 400 MW of CTs in Lyon County, Minnesota … by 2026 … We would also initiate a proceeding in Minnesota for the Lyon County CT.
        - Action plan: "we also propose initiating a new regulatory docket in the near-term to discuss broader blackstart issues that would include the consideration of other blackstart additions"
- Regarding demand response (DR) resources:
    - add more than 800 MW of additional[6] demand savings by 2034.
        - Action plan: "The Alternate Plan continues to include the acquisition of 400 MW of incremental DR resources by 2023."
- Regarding energy efficiency resources:
    - add more than 780 GWh in average annual energy savings.
- Regarding energy storage resources:
    - add 250 MW of storage.

Based upon the alternate plan, the Company requests the following items:

- approval of Company ownership of Sherco and King gen-tie lines plus renewable resources added on the lines;
- approval of 400 MW of CTs in Lyon County, Minnesota and 400 MW CTs in Fargo, North Dakota;
- approval to continue pursuing a 10-year extension for our Monticello Nuclear plant; and

[6] When compared to the level approved in Xcel's last IRP.

- approval for black start shift to zonal approach and need for black start resources in each zone which includes:
  - two specific black start additions in Minnesota and Wisconsin by 2026; and
  - new regulatory docket to discuss broader black start issues that would include the consideration of other black start additions in other zones in the out years of our plan to consider optimal technologies.
- use of the Modified Track 2 process for the following acquisition proceedings:
  - solar and wind resources that utilize the transmission interconnection at Sherco;
  - solar resource that utilize the transmission interconnection at King;
  - approximately 400 MWs of CTs in Lyon County to connect to the transmission interconnection at Sherco;
  - any wind or solar additions needed before the next resource plan.

Finally, Xcel anticipates the following regulatory filings:

- a CN proceeding for the Monticello life extension;
- a CN and Route Permit for the Sherco gen-tie line;
- a CN and Route Permit for the King gen-tie line;
- site permits needed for any acquisitions of generation, including generation to utilize the Sherco and King interconnections; and
- a new regulatory docket to discuss broader black start issues that would include the consideration of other black start additions in other zones in the out years of our plan to consider optimal technologies.

II. DEPARTMENT STAFF SUPPLEMENTAL COMMENTS

A. BLACK START UNITS

The Company's reply comments describe the proposed changes to the black start process as planning to move from an approach that relies on a limited number of centrally located units to a process that utilizes an array of decentralized units. The Company also proposes to have a dedicated proceeding outside of this IRP to analyze the proposed black start plan. The Company's response to XLI Information Request (IR) No. 149 provides two basic reasons for this:

> We believe a dedicated proceeding outside of this Integrated Resource Plan is the best venue for these issues for several reasons. First, although there are some exceptions, historically, the Commission has used resource planning as a tool to assess and determine the appropriate size, type, and timing of generation resources – and not the location of particular resources. Our planned zonal restoration approach, however, specifically requires the consideration of resource locations for reliability purposes. Second, the identity of black start resources and system restoration plans are highly confidential. A proceeding dedicated to a discussion of these resources, conducted with appropriate measures to protect sensitive

> information, minimizes the risk of inadvertently disclosing information regarding our restoration plan that could be exploited by a bad actor.

Department Staff agrees with Xcel's rationale regarding a separate black start proceeding. Note that for purposes of modeling the Company required EnCompass to add certain units. See Table 4-9 of the Company's reply comments for details. Department Staff did not change the Company's inputs regarding the expansion units forced to be added by EnCompass as part of the proposed black start plan. First, Department Staff concluded that the forced units were reasonably reflective of what might be approved by the Commission. If the forced units are not reflective of the plan ultimately approved by the Commission, the actual black start plan would be revised in the Company's next IRP. Second, EnCompass added additional units of the same type as the black start units for economic reasons. This makes it unlikely that the forced units biased the overall expansion plan in a meaningful way.

B. DEMAND AND ENERGY FORECASTS

1. Xcel's Adjustments

The forecast review in this docket had two goals: first to be done quickly and second to establish an acceptable base forecast for long term planning purposes. Given these limits, the forecast review did not address some details that would normally be part of forecast analysis. Thus, as stated in Department Staff 's February 11, 2021 Comments, for this IRP, Department Staff neither reviewed the technical details of Xcel's forecasts nor tested all the Company's previous or current statistical models. Instead, Department Staff examined the potential for bias in Xcel's forecasting over the past 15 years. Department Staff's review indicated that the Company's demand and energy forecasts have a systematic bias. Based upon this conclusion Department Staff made adjustments to the Company's demand and energy forecasts in the capacity expansion models used in Comments and Reply Comments. In addition, Department Staff recommended that the Commission:

> require Xcel to file and use a forecast from an independent consultant in any future regulatory proceedings. This requirement will enable Xcel's proceedings to continue normally while the Company attempts to audit and identify the flaws in their current forecast process.

In reply comments Xcel identified five contributors to the historical forecast variance identified by Department Staff. Xcel stated that "[t]hese factors were not known at the time the forecasts were developed and can be analyzed and quantified without testing the Company's previous or current statistical models." The five factors are:

- Weather—Department Staff's variance compared actual peak demand to weather-normalized forecasts. During the 15-year period of 2004-2018, weather impacting the peak day was cooler than normal in eight years (contributing to the forecast being higher than actual) and hotter than normal in seven years (contributing to the forecast being lower than actual).

- Wholesale Load[7]—Between 2009 and 2013, all of the Company's contracts with firm wholesale customers expired; all forecasts prior to July 2012 were overstated by the amount of wholesale load that ultimately was not served by the Company.
- Large Customer Load Changes—In 2011 the Company experienced several reductions in large customer loads; all forecasts prior to the reductions assumed that the load would be served.
- Combined Heat and Power (CHP) Operations—In 2017 a customer began serving part of its load from CHP operations and Xcel began adjusting forecasts in 2014 for this event. Thus, all forecasts prior to August 2014 were overstated beginning in 2017 due to the loss of load.
- Energy Efficiency[8]—actual energy efficiency achievements have consistently been greater than forecasted, contributing to the forecast being higher than actual energy and demand.

Using the five factors discussed above the Company updated Department Staff's forecast variance analysis. The Company's updated analysis of demand forecasting was provided in the reply comments at Table 6-1. The Company's updated analysis of energy forecasting was provided in the reply comments at Table 6-3. Department IR Nos. 115 and 116 requested data supporting the Company's variance calculations as shown in Tables 6-1 and 6-3; however, the initial response contained errors. Xcel provided the correct data underlying Tables 6-1 and 6-3 in response to Department IR Nos. 117 and 118.

After briefly reviewing Xcel's explanation and the Company's additional forecasting data (while neither reviewing the technical details of Xcel's forecasts nor testing all the Company's previous or current statistical models), Department Staff's conclusions are as follows:

- First, regarding weather, Department Staff agrees that a forecast assuming normal weather should be compared to weather normalized actuals. To conserve resources Department Staff did not review the Company's weather normalization calculations. Instead, Department Staff simply accepts the Company's adjustment for IRP purposes only.
- Second, regarding wholesale load, large customer load changes, and CHP operations Department Staff agrees with the Company's adjustments. Again, Department Staff did not review any detailed supporting documents to conserve resources. Instead, Department Staff assumed that the adjustments were reasonably measurable. Again, Department Staff accepts the Company's adjustments for IRP purposes only.

[7] Until notified by the wholesale customer that its contract would not be extended, the Company concluded it was reasonable and necessary for the Company to include the customer's forecasted energy and demand in its long-term forecasts.
[8] Beginning with the October 2008 forecast, the Company incorporated an adjustment to the demand and energy forecast to account for future energy efficiency amounts.

- Third, regarding energy efficiency, Department Staff notes that the Company's calculations added first-year savings over several years rather than assuming some of the savings expires in future years. The Company's response to Department IR No. 119 states that first-year savings were added based on the method used for forecasting DSM achievements used in the 2008-2018 load forecasts, all of which included a 14-year lifetime assumption for all DSM achievements. Department Staff also notes that incorporating forecast adjustments based upon the difference between what did happen (forecast data with energy efficiency achievements) and what would have happened in an alternate reality (forecast data with assumed energy efficiency achievements removed) is speculative. As with weather normalization, to conserve resources, Department Staff did not review the Company's energy efficiency calculations. Instead, Department Staff simply accepts the Company's adjustment for IRP purposes only.

2. *Demand Forecast*

Having decided to accept the Company's adjustments for IRP purposes only, Department Staff next reviewed Table 6-1 and the Company's response to Department IR Nos. 115 and 117. This revised data clearly shows that the Company's adjustments did not remove the bias in the demand forecast. Even accepting the Company's adjustments about 90 percent of the demand forecast variances are still too high. However, the degree of bias has been reduced by the adjustments.

The Company observed that the remaining variances are within the bands typically used in IRPs. Department Staff agrees with this observation. However, it is not relevant. The difference between forecast error and forecast bias must be kept in mind. Here, a forecast error is the difference between the forecast value and the actual or experienced value. This difference is expected to be randomly distributed—sometimes too high and sometimes too low. Over a long duration the errors should be too high about half the time and too low about half the time. A forecast bias occurs when the forecast errors are too high most of the time (or vice versa).

The purpose of the forecast band is to account for forecast error not forecast bias.[9] Forecast bias is addressed by changing the model inputs themselves. Perceived bias is the reason other modeling inputs have been adjusted by parties in this proceeding. To account for the demand forecast bias remaining after incorporating Xcel's revisions for IRP purposes only, Department Staff recalculated the demand forecast adjustments as shown in Table 1 below. Similar to the original adjustment, Department Staff constructed the forecast adjustments using two criteria: maintaining any adjustment for two years and adjusting Xcel's forecast using two percentage point increments. The adjustments were applied to the variances calculated by Xcel in Department IR Nos. 115 and 117.

[9] This also applies to the band applied to any other model input such as natural gas prices.

Table 1: Demand Forecast Variance and Adjustment

Forecast Year	Remaining Average Forecast Error	Department Forecast Adjustment	Difference
1	1.1%	0.0%	1.1%
2	1.6%	0.0%	1.6%
3	1.7%	-2.0%	-0.3%
4	2.3%	-2.0%	0.3%
5	3.0%	-2.0%	1.0%
6	3.6%	-4.0%	-0.4%
7	4.6%	-4.0%	0.6%
8	5.9%	-6.0%	-0.1%
9	7.7%	-6.0%	1.7%
10	8.9%	-10.0%	-1.1%
11	12.0%	-10.0%	2.0%
12		-10.0%	
13		-10.0%	
14		-10.0%	
15		-10.0%	

Note that the oldest forecast is from 2008, so there is no forecast error data for years 12 to 15.

3. Energy Forecast

Department Staff next reviewed Table 6-3 and Xcel's reply to Department IR Nos. 116 and 118. As with the demand forecasts, the revised data clearly shows that the Company's adjustments did not remove the bias in the energy forecasts. Accepting the Company's adjustments, for IRP purposes only, about 65 percent of the energy forecast variances are still too high.

As before, to account for the remaining energy forecast bias Department Staff recalculated the energy forecast adjustments as shown in Table 2 below. As with the demand forecast adjustment, Department Staff used a minimum two-year interval and two percentage point increments to calculate the energy forecast adjustment from the post-adjustment variances calculated by Xcel in Department IR Nos. 116 and 118.

Table 2: Energy Forecast Variance and Adjustment

Forecast Year	Remaining Average Forecast Error	Department Forecast Adjustment	Difference
1	0.0%	0.0%	0.0%
2	0.0%	0.0%	0.0%
3	0.6%	0.0%	0.6%
4	1.0%	0.0%	1.0%
5	1.4%	-2.0%	-0.6%
6	1.9%	-2.0%	-0.1%
7	3.2%	-4.0%	-0.8%
8	4.5%	-4.0%	0.5%
9	5.7%	-4.0%	1.7%
10	6.6%	-6.0%	0.6%
11	5.5%	-6.0%	-0.5%
12		-6.0%	
13		-6.0%	
14		-6.0%	
15		-6.0%	

Again, the oldest forecast is from 2008, so there is no forecast error data for years 12 to 15.

B. ENCOMPASS AND CONVERGENCE TOLERANCE

1. Background

In this proceeding Xcel used EnCompass both as a CEM and as a production cost model. First, Xcel runs a scenario using EnCompass as a CEM. The purpose of this step is to determine a least cost expansion plan. During this step Xcel's inputs simplify EnCompass' operations, for example, using one off-peak day and one on-peak day each month. Second, Xcel locks-in the expansion plan (from the first step) and re-runs the scenario using EnCompass as a production cost model. The results reported by the Company are from the production cost model run. This is discussed further in the next section.

When used as a CEM, EnCompass uses a mathematical method called mixed integer programming (MIP) to determine the least cost expansion plan. At a high level, EnCompass' MIP process involves two basic steps. In the first step EnCompass determines the potential ideal (or lowest possible cost) expansion plan by adding fractions of units. For example, the potential ideal plan may involve adding 30 percent of a wind unit in 2023, 70 percent of a solar unit in 2025, and 20 percent of a combustion

III. DEPARTMENT RECOMMENDATIONS

A. XCEL'S REQUESTS

Based upon the alternate plan, the Company requests the following items:

- approval of Company ownership of Sherco and King gen-tie lines plus renewable resources added on the lines;
- approval of 400 MW of CTs in Lyon County, Minnesota and 400 MW CTs in Fargo, North Dakota;
- approval to continue pursuing a 10-year extension for our Monticello Nuclear plant; and
- approval for black start shift to zonal approach and need for black start resources in each zone which includes:
    - two specific black start additions in Minnesota and Wisconsin by 2026; and
    - new regulatory docket to discuss broader black start issues that would include the consideration of other black start additions in other zones in the out years of our plan to consider optimal technologies.
- use of the Modified Track 2 process for the following acquisition proceedings:
    - solar and wind resources that utilize the transmission interconnection at Sherco;
    - solar resource that utilize the transmission interconnection at King;
    - approximately 400 MWs of CTs in Lyon County to connect to the transmission interconnection at Sherco;
    - any wind or solar additions needed before the next resource plan.

Department Staff's recommendations regarding the Company's requests are as follows. First, regarding approval of Company ownership of Sherco and King gen-tie lines plus renewable resources added on the lines: Department Staff agrees with Xcel that one of the few realistic paths in the near term for adding substantial, cost-effective capacity of any type is through Company ownership of Sherco and King gen-tie lines and re-use of the existing interconnection rights.

Second, regarding approval of 400 MW of CTs in Lyon County, Minnesota and 400 MW CTs in Fargo, North Dakota. Department Staff recommend that no Commission determination be made regarding these requests. No optional capacity resources were added in Department Staff's CEM modeling in the near-term and any units associated with the black start plan should be addressed in the proposed black start proceeding.

Third, regarding approval to continue pursuing a 10-year extension for Monticello, Department Staff recommend that no Commission determination be made regarding this request. This is because the Company has since filed the requisite CN.

Fourth, regarding approval for black start shift to zonal approach and need for black start resources in each zone, Department Staff recommend that no Commission determination be made regarding this request. This request and all requests related to black start should be addressed by the Commission as part of the proposed black start proceeding.

Fifth, regarding approval to use of the Modified Track 2 process, Department Staff agree with the Company that the Commission should approve use of the Track 1/Modified Track 2 process as discussed in Department Staff's February 11, 2021 comments. However, Department Staff recommend that the Commission determine that the Commission-approved Track 1/Modified Track 2 bidding process applies in all instances where Xcel intends to acquire 100 MW of capacity for a duration longer than five years.

B. DEPARTMENT STAFF RECOMMENDATIONS

Regarding forecasting, Department Staff considers Xcel's reply comments to have partially explained the poor quality of the Company's forecasts. Department Staff will continue to review the Company's forecasts for accuracy in future proceedings as time and resources allow.

Regarding the baseload study, Department Staff recommends the Commission order Xcel to:

- retire King by the early date, 2028;
- retire Sherco unit 3 by the early date, 2030;
- retire Monticello by the normal date—the end of current license life in 2030; and
- proceed assuming Prairie Island will undergo a 10-year license extension and re-study the retirement date in the next resource plan.

Regarding supply units in the action plan, Department Staff recommends:

- proceed assuming the Company will not add wind resources during the action plan period;
- proceed assuming the Company will not add capacity resources during the action plan period; and
- acquire a total of approximately 1,125 MW of solar capacity, both distributed and central station, by 2024, contingent upon prices being reasonable.

Regarding energy efficiency, Department Staff recommends that the Commission take no action regarding the Company's proposed level of energy efficiency resources.

Regarding resource acquisition, Department Staff recommends that the Commission:

- approve the Track 1 bidding process, as outlined in Department Staff's February 11, 2021 comments, for resource acquisitions in which Xcel determines to not bid;
- approve the Modified Track 2 bidding process, as outlined in Department Staff's February 11, 2021 comments, for resource acquisitions in which Xcel determines to bid;
- require that any RFP documents for peaking resources issued by Xcel be technology neutral;
- cap any ROFO offer made by Xcel at net book value;
- require any RFP issued by Xcel to include the option for both PPAs and BOTs unless the Company can demonstrate why either a PPA or BOT proposal is not feasible; and
- take no action on the request for "flexibility to evaluate and pursue the required incremental DR."

/ar

☒ **Not Public Document – Not For Public Disclosure**
☐ **Public Document – Not Public Data Has Been Excised**
☐ **Public Document**

Xcel Energy		Information Request No.	8
Docket No.:	E002/CN-21-668		
Response To:	Minnesota Department of Commerce		
Requestor:	Stephen Rakow		
Date Received:	March 14, 2022		

Question:
Topic: Energy and Demand Forecasts

a. Please provide all of the unedited input and output files from all of the statistical software applications used to produce the energy and demand forecast inputs to the EnCompass modeling included in the Petition.
b. Please identify and indicate all of the adjustments made to the data or forecast in part (A) above. Please provide the rationale for the adjustments.

For Parts A and B please provide the requested data in a Microsoft Excel executable format with all links and formulae intact. If any of these links target an outside file, please provide all such additional files.

In addition, whenever acronyms are used in the data given in response to Parts A through B, and any and all other parts above, please provide an explanation of all acronyms used AND also provide a brief but complete explanation of the source of each data series that is provided.

If the above information has already been provided in written petition or in response to an earlier information request, please identify the specific petition cite(s) or information request number(s).

Response:

Please see the input and output files provided with this response and available through the External Share Site: Xcel Energy Discovery Responses - E002/CN-21-668 Monticello Nuclear Dry Cask Storage CON.

a. Please see the following files, which provide the input and output from the statistical software application used to produce the energy and demand forecast.

<table>
<tr><th>Concept</th><th>File Name</th><th>File Description</th></tr>
<tr><td>Michigan Residential Sales</td><td>MIResTotSales</td><td rowspan="17">Each file provides the standard model output which includes the following information:

Model input data ("Data" tab)

Model input data statistics ("Dstat" tab)

Model input data correlation table ("Corr" tab)

Model coefficients and variable definitions ("Coef" tab)

Model statistics ("Mstat" tab)

Actual and predicted values, residuals, % residuals, and standard residuals ("Err" tab)

Elasticity for each variable ("Elas" tab)

Contribution of each variable to the predicted value ("BX" tab)

For variables that are the aggregation of other variables, the disaggregated data is provided on the tab "Disaggregated Data"</td></tr>
<tr><td>Michigan Small Commercial/Industrial Sales</td><td>MISmCISales</td></tr>
<tr><td>Minnesota Large Commercial/Industrial Sales</td><td>MNLgCISales</td></tr>
<tr><td>Minnesota Other Sales</td><td>MNOSSales</td></tr>
<tr><td>Minnesota Residential Heating Sales</td><td>MNRHSales</td></tr>
<tr><td>Minnesota Residential w/o Heating Sales</td><td>MNRXSales</td></tr>
<tr><td>Minnesota Small Commercial/Industrial Sales</td><td>MNSmCISales</td></tr>
<tr><td>Minnesota Street Lighting Sales</td><td>MNStLtSales</td></tr>
<tr><td>North Dakota Residential Heating Sales</td><td>NDRHSales</td></tr>
<tr><td>North Dakota Residential w/o Heating Sales</td><td>NDRXSales</td></tr>
<tr><td>North Dakota Small Commercial/Industrial Sales</td><td>NDSmCISales</td></tr>
<tr><td>South Dakota Residential Heating Sales</td><td>SDRHSales</td></tr>
<tr><td>South Dakota Residential w/o Heating Sales</td><td>SDRXSales</td></tr>
<tr><td>South Dakota Small Commercial/Industrial Sales</td><td>SDSmCISales</td></tr>
<tr><td>Wisconsin Residential Sales</td><td>WIResTotSales</td></tr>
<tr><td>Wisconsin Small Commercial/Industrial Sales</td><td>WISmCISalesxSand</td></tr>
<tr><td>System Peak Demand</td><td>Peak_DSMAdj_2019v2.3a_woAR</td></tr>
</table>

b. Please refer to the following files.

File Name	Description
NSP MI Fcst	Michigan sales master forecast file
NSP MN Fcst v2.3	Minnesota sales master forecast file
NSP ND Fcst	North Dakota sales master forecast file
NSP SD Fcst	South Dakota sales master forecast file
NSP WI Fcst	Wisconsin sales master forecast file
2019v2.3 Peak Model_noAR	Peak demand master forecast file

2019v2.3 Forecast NSP Elec Energy_Calendar	Total energy forecast file
2019v2.3 Forecast NSP Elec Energy and Peak Demand	Forecast summary file

Within each of the state-level sales master forecast files are tabs for each class. Within these tabs, the billing month sales forecasts from the output files in Part a were converted to calendar month sales and any adjustments were made to the forecasts. These adjustments are described below.

For the Minnesota and South Dakota jurisdictions, the sales model historical data and output for the Residential without Space Heat, Residential with Space Heat, Small Commercial and Industrial and Large Commercial and Industrial classes were adjusted to account for the impacts of Demand-Side Management (DSM) savings. The calendar month sales forecasts were adjusted to remove the continuing impacts of historical DSM programs and the future impacts of DSM programs implemented after May 2019. In addition to adjusting the sales forecast for the impact of Xcel sponsored DSM programs, the sales forecasts for all jurisdictions were adjusted for the impacts of changes in lighting codes and standards that are not included in Xcel's sponsored DSM programs.

For the Minnesota jurisdiction, the sales model historical data and output for the Residential without Space Heat, Residential with Space Heat, Small Commercial and Industrial and Large Commercial and Industrial classes were adjusted to account for distributed behind-the-meter (roof top) solar generation. The historical sales data used in the regression models were adjusted to add historical impacts of solar generation. The calendar month sales forecasts were adjusted to remove the impact of behind-the-meter solar generation.

For all jurisdictions, the calendar month sales forecasts for the Residential classes were adjusted for the expected impacts from the increasing use of electric vehicle charging.

The Minnesota and Wisconsin Large Commercial and Industrial sales forecasts were adjusted for customer-specific load additions and/or losses, based on input from Xcel Energy's Account Management team. The Wisconsin Small and Large Commercial and Industrial sales forecasts were adjusted for expected incremental sand mining industry sales.

Sales for each jurisdiction are summed to a total retail level and then losses were added to derive jurisdictional energy forecasts. The jurisdictional energy forecasts were summed to derive the total system energy forecast. These calculations are provided in the file "2019v2.3 Forecast NSP Elec Energy_Calendar". The losses were calculated based on a historical average loss factor for each jurisdiction.

The peak demand forecast output was adjusted for the expected impacts of DSM savings and the impacts of changes in lighting codes and standards that are not included in Xcel's sponsored DSM programs. The peak demand forecast was also adjusted for the expected impacts of behind-the-meter solar generation and electric vehicle charging. The peak demand forecast was also adjusted for customer-specific load additions and/or losses. These adjustments are provided in the file " 2019v2.3 Peak Model_noAR".

The file "2019v2.3 Forecast NSP Elec Energy and Peak Demand" provides a summary of the system level energy and peak demand forecast.

Attachments to this response include sales data the Company considers to be Trade Secret information protected by the Minnesota Data Practices Act. That information has economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons and is subject to efforts by the Company to protect the information from public disclosure. Xcel Energy maintains the marked sales data as a trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Some of the attachments also include not-public customer data protected under the Minnesota Data Practices Act. Specific protected data includes the name, address or related usage, consisting of "private data on individuals" and "confidential customer data." As such, any unique information that can identify an individual customer is maintained by Xcel Energy as not-public data and protected from public disclosure. For this reason, we ask that the data be treated as non-public data pursuant to Minn. Stat. § 13.37, subd. 1(b).

Preparer:	Luke Jaramillo
Title:	Senior Energy Forecasting Analyst
Department:	Energy Forecasting
Telephone:	303-571-6239
Date:	March 24, 2022

☐ **Not Public Document – Not For Public Disclosure**
☐ **Public Document – Not Public Data Has Been Excised**
☒ **Public Document**

Xcel Energy		Information Request No.	10
Docket No.:	E002/CN-21-668		
Response To:	Minnesota Department of Commerce		
Requestor:	Stephen Rakow		
Date Received:	March 14, 2022		

Question:
Topic: Energy and Demand Forecasts

a. Please update the Company's response to Department Information Request No. 115 and 116 (both as revised August 23, 2021) in Docket No. E002/RP-19-368 to include forecast vintages and actuals made available since the revised response was prepared.
b. For each adjustment (CHP, Large Customer, Wholesale Energy, DSM Variance, and any additional adjustments), please provide a spreadsheet that shows how each adjustment was calculated.

Please provide the requested data in a Microsoft Excel executable format with all links and formulae intact. If any of these links target an outside file, please provide all such additional files.

Response:

Please see the actual forecast variance files provided with this response and available through the External Share Site: Xcel Energy Discovery Responses - E002/CN-21-668 Monticello Nuclear Dry Cask Storage CON.

a. For the requested updates please refer to 19-0368 DOC-115_Attachment A-updated 03-24-2022.xlsx and 19-0368 DOC-116_Attachment A-updated 03-24-2022.xls. In these attachments the actual to forecast variance is calculated for both energy and peak demand. To account for unforeseen and unpreventable events and situations, the Company has identified adjustments to the historical forecasts that help explain the forecast variance from actual energy and peak demand. These adjustments provide a more accurate evaluation of the forecast variance. While the initial analysis indicated that the Company's forecasts were over forecasting energy and peak demand, taking into account these unforeseen and unpreventable events and situations significantly reduces the overall forecast variance. Since 2017, the energy forecast variances have averaged 0.3% below actual and peak demand forecast variances have averaged 1.8% above actual.

We note that the COVID-19 pandemic had an unprecedented impact in 2020 on both energy and peak demand, but we have not made any adjustments to this analysis to account for that impact.

The attachments were updated for forecast vintages developed in March 2019, July 2019, March 2020, July 2020, March 2021, and July 2021. This update also includes the extension of the forecast horizon to 2021 for the provided forecasts developed from October 2008 through 2021.

The forecasts provided reflect the corporate forecast which is used for various aspect of the Company's planning and regulatory needs. The corporate forecast is the starting point used in resource planning but may have been adjusted to determine the Company's resource needs.

b. Please refer to DOC-010_Attachment A.xlsx for the calculation of the energy and peak demand adjustments used to reconcile the forecasts provided in the response to part a. above.

Preparer:	Luke Jaramillo
Title:	Senior Energy Forecasting Analyst
Department:	Energy Forecasting
Telephone:	303-571-6239
Date:	March 24, 2022

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Xcel Energy		Information Request No.	11
Docket No.:	E002/CN-21-668		
Response To:	Minnesota Department of Commerce		
Requestor:	Stephen Rakow		
Date Received:	August 31, 2022		

Question:
Topic: Energy and Demand Forecasts
Reference(s): Click or tap here to enter text.

Request:

a. Please provide all of the unedited input and output files from all of the statistical software applications used to produce the Company's most recent, system-wide energy and demand forecast.
b. Please identify and indicate all of the adjustments made to the data or forecast in part (A) above. Please provide the rationale for the adjustments.

For Parts A and B please provide the requested data in a Microsoft Excel executable format with all links and formulae intact. If any of these links target an outside file, please provide all such additional files.

In addition, whenever acronyms are used in the data given in response to Parts A through B, and any and all other parts above, please provide an explanation of all acronyms used AND also provide a brief but complete explanation of the source of each data series that is provided.

If the above information has already been provided in written petition or in response to an earlier information request, please identify the specific petition cite(s) or information request number(s).

Response:

a. Please see the following files listed below from the Company's 2022v1.0 forecast release. The 2022v1.0 forecast is the most recent forecast used by the Company to produce inputs for the EnCompass modeling. These files provide the input and output from the statistical software application used to produce the energy and demand forecast. The Company recently completed its 2022v2.0 forecast but has not produced inputs for EnCompass modeling.

Concept	Attachment	File Description
Michigan Residential Sales	21-0668 DOC-011_Att A - MIResTotSales	Each file provides the standard model output which includes the following information: Model input data ("Data" tab) Model input data statistics ("Dstat" tab) Model input data correlation table ("Corr" tab) Model coefficients and variable definitions ("Coef" tab) Model statistics ("Mstat" tab) Actual and predicted values, residuals, % residuals, and standard residuals ("Err" tab) Elasticity for each variable ("Elas" tab) Contribution of each variable to the predicted value ("BX" tab) For variables that are the aggregation of other variables, the disaggregated data is provided on the tab "Disaggregated Data"
Michigan Small Commercial/Industrial Sales	21-0668 DOC-011_Att B - MISmCISales	
Minnesota Large Commercial/Industrial Sales	21-0668 DOC-011_Att C - MNLgCISales	
Minnesota Other Sales	21-0668 DOC-011_Att D - MNOSSales	
Minnesota Residential Heating Sales	21-0668 DOC-011_Att E - MNRHSales	
Minnesota Residential w/o Heating Sales	21-0668 DOC-011_Att F - MNRXSales	
Minnesota Small Commercial/Industrial Sales	21-0668 DOC-011_Att G - MNSmCISales	
Minnesota Street Lighting Sales	21-0668 DOC-011_Att H - MNStLtSales	
North Dakota Residential Heating Sales	21-0668 DOC-011_Att I - NDRHSales	
North Dakota Residential w/o Heating Sales	21-0668 DOC-011_Att J - NDRXSales	
North Dakota Small Commercial/Industrial Sales	21-0668 DOC-011_Att K - NDSmCISales	
South Dakota Residential Heating Sales	21-0668 DOC-011_Att L - SDRHSales	
South Dakota Residential w/o Heating Sales	21-0668 DOC-011_Att M - SDRXSales	
South Dakota Small Commercial/Industrial Sales	21-0668 DOC-011_Att N - SDSmCISales	
Wisconsin Residential Sales	21-0668 DOC-011_Att O - WIResTotSales	
Wisconsin Small Commercial/Industrial Sales	21-0668 DOC-011_Att P - WISmCISalesxSand	
System Peak Demand	21-0668 DOC-011_Att Q - 2022v1.0 Peak Model	

b. Please refer to the following files.

Attachment	Description
21-0668 DOC-011_Att R - NSP MI Fcst	Michigan sales master forecast file
21-0668 DOC-011_Att S - NSP MN Fcst	Minnesota sales master forecast file
21-0668 DOC-011_Att T - NSP ND Fcst	North Dakota sales master forecast file
21-0668 DOC-011_Att U - NSP SD Fcst	South Dakota sales master forecast file
21-0668 DOC-011_Att V - NSP WI Fcst	Wisconsin sales master forecast file
21-0668 DOC-011_Att Q - 2022v1.0 Peak Model	Peak demand master forecast file
21-0668 DOC-011_Att W - 2022v1.0 Forecast NSP Elec Energy_Calendar	Total energy forecast file
21-0668 DOC-011_Att X - 2022v1.0 Forecast NSP Elec Energy and Peak Demand	Forecast summary file

Within each of the state-level sales master forecast files are tabs for each class. Within these tabs, the billing month sales forecasts from the output files in Part a were converted to calendar month sales and any adjustments were made to the forecasts. These adjustments are described below.

For the Minnesota and South Dakota jurisdictions, the sales model historical data and output for the Residential without Space Heat, Residential with Space Heat, Small Commercial and Industrial and Large Commercial and Industrial classes were adjusted to account for the impacts of Demand-Side Management (DSM) savings. The calendar month sales forecasts were adjusted to remove the continuing impacts of historical DSM programs, expected over-achievement of DSM goals, and the future impacts of DSM programs implemented after December 2021.

For the Minnesota jurisdiction, the sales model historical data and output for the Residential without Space Heat, Residential with Space Heat, Small Commercial and Industrial and Large Commercial and Industrial classes were adjusted to account for distributed behind-the-meter (roof top) solar generation. The historical sales data used in the regression models were adjusted to add historical impacts of solar generation. The calendar month sales forecasts were adjusted to remove the impact of behind-the-meter solar generation.

For all jurisdictions, the calendar month sales forecasts for the Residential and Small and Large Commercial and Industrial classes were adjusted for the expected impacts from the increasing use of electric vehicle charging.

The Minnesota and Wisconsin Large Commercial and Industrial sales forecasts were adjusted for customer-specific load additions and/or losses, based on input from Xcel Energy's Account Management team. The Wisconsin Small and Large Commercial and Industrial sales forecasts were adjusted for expected incremental sand mining industry sales.

Sales for each jurisdiction are summed to a total retail level and then losses were added to derive jurisdictional energy forecasts. The jurisdictional energy forecasts were summed to derive the total system energy forecast. These calculations are provided in 21-0668 DOC-011_Att W - 2022v1.0 Forecast NSP Elec Energy_Calendar. The losses were calculated based on a historical average loss factor for each jurisdiction.

The peak demand forecast output was adjusted for the expected impacts of DSM savings. The peak demand forecast was also adjusted for the expected impacts of behind-the-meter solar generation and electric vehicle charging. The peak demand forecast was also adjusted for customer-specific load additions and/or losses. These adjustments are provided in 21-0668 DOC-011_Att Q - 2022v1.0 Peak Model.

Please refer to 21-0668 DOC-011_Att X - 2022v1.0 Forecast NSP Elec Energy and Peak Demand for a summary of the system level energy and peak demand forecast.

Several attachments to this response include Trade Secret information, as marked, that is protected by the Minnesota Data Practices Act. That information has economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons and is subject to efforts by the Company to protect the information from public disclosure. Xcel Energy maintains this information as a trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. For this reason, we ask that the data be treated as not-public data pursuant to Minn. Stat. § 13.37, subd. 1(b).

Preparer:	Luke Jaramillo
Title:	Senior Forecasting Analyst
Department:	Sales, Energy and Demand
Telephone:	(303) 294-6239
Date:	September 13, 2022

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Xcel Energy		Information Request No.	13
Docket No.:	E002/CN-21-668		
Response To:	Minnesota Department of Commerce		
Requestor:	Stephen Rakow		
Date Received:	August 31, 2022		

Question:
Topic: Energy and Demand Forecasts
Reference(s): Click or tap here to enter text.

Request:

a. Please provide a table showing the outputs from most recent system-wide annual energy forecast and the energy forecast used to create inputs for the EnCompass modeling presented in the petition.
b. Please provide a table showing the outputs from most recent system-wide annual peak demand forecast and the peak demand forecast used to create inputs for the EnCompass modeling presented in the petition.

Response:
Please see Attachment A to this response. The initial forecast vintage provided in this petition used to create the inputs for the EnCompass modeling was 2019v2.3. The most recent forecast vintage to be used to create inputs for the EnCompass modeling is 2022v1.0. Please note that the data provide in Attachment A included an adjustment for DSM. In Encompass, DSM is included as a supply-side resource.

Preparer:	Luke Jaramillo
Title:	Senior Forecasting Analyst
Department:	Sales, Energy and Demand Forecasting
Telephone:	(303) 294-6239
Date:	September 13, 2022

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Xcel Energy		Information Request No.	15
Docket No.:	E002/CN-21-668		
Response To:	Minnesota Department of Commerce		
Requestor:	Sachin Shah		
Date Received:	February 3, 2023		

<u>Question:</u>

Reference(s): In the Matter of the Application of Northern States Power Co., d/b/a Xcel Energy., (Xcel or Company) for Certificate of Need for Additional Dry Cask Storage at Monticello Plant Independent Spent Fuel Storage Installation (ISFSI).

A. Please provide Xcel Energy's system peak demand, energy, and customer count forecasts using the most recent system forecast available and all the necessary data in sufficient detail to replicate the forecasts referenced herein.

B. As part of the Company's response to subpart (A) above, please identify (for example, Spring 2022, Fall 2022?), describe and explain the forecast vintage provided.

C. Please describe the intervals used for each model.

D. As part of your response to parts (A) through (C) above, please explain if the peak demand data used and forecasted is "net peak" or "base peak".

E. If any adjustments were made to any of the explanatory or dependent variables by rate class or model that were used by the Company as identified in its responses to parts (A) through (D) above, then provide the disaggregated data as well.

Please provide the requested data in a Microsoft Excel executable format (*.xlsx) with all links and formulae intact. If any of these links target an outside file, please provide all such additional files.

In addition, whenever acronyms are used in the data given in response to all the parts above, please provide an explanation of all acronyms used AND also provide a brief but complete explanation of the source of each data series that is provided.

If this information has already been provided in the application or in response to an earlier information request (IR), please identify the specific cite(s) or IR number(s).

<u>Response:</u>

A. Refer to Attachments 21-668 DOC-15_A.xlsx through 21-668 DOC-15_BB. Attachments 21-668 DOC-15_A.xlsx through 21-668 DOC-15_AU contain the Customer Count, Energy Sales, and Peak Demand raw regression model outputs exported from MetrixND. Attachments 21-668 DOC-15_AV.xlsx through 21-668 DOC-15_AZ format and adjust the raw regression outputs into the final sales estimates by State. Attachment 21-668 DOC-15_BA formats the raw peak demand model into the final peak outlook. Attachment 21-668 DOC-15_BB summarizes the NSP system forecast that was used in the Company's Alternate Plan. Each attachment is described in the table below. All forecasts are from the Company's 2022 Fall forecast.

File Name	File Contents	File Type	Description
21-0668 DOC-15_Att A_NON-PUBLIC.xlsx	MN Residential without Space Heat Customer Counts	Metrix Output	Each file contains the standard model output which includes the following information:
21-0668 DOC-15_Att B_NON-PUBLIC.xlsx	MN Residential with Space Heat Customer Counts	Metrix Output	Model input data ("Trade Secret – Data" tab)
21-0668 DOC-15_Att C_NON-PUBLIC.xlsx	MN Small Commercial and Industrial Customer Counts	Trend Calc	Model input data statistics ("Dstat" tab)
21-0668 DOC-15_Att D.xlsx	MN Large Commercial and Industrial Customer Counts	Trend Calc	Model coefficients and variable definitions ("Coef" tab)
21-0668 DOC-15_Att E_NON-PUBLIC.xlsx	MN Public Street and Highway Lighting Customer Counts	Metrix Output	Model input data correlation table ("Corr" tab)
21-0668 DOC-15_Att F.xlsx	MN Other Public Authority Customer Counts	Metrix Output	Model coefficients and variable definitions ("Coef" tab)
21-0668 DOC-15_Att G.xlsx	MN Interdepartmental Customer Counts	Trend Calc	Model statistics ("Mstat" tab)
21-0668 DOC-15_Att H_NON-PUBLIC.xlsx	ND Residential without Space Heat Customer Counts	Metrix Output	Actual and predicted values, residuals, % residuals, and standard residuals ("Err" tab)
21-0668 DOC-15_Att I_NON-PUBLIC.xlsx	ND Residential with Space Heat Customer Counts	Metrix Output	Elasticity for each variable ("Elas" tab)
21-0668 DOC-15_Att J.xlsx	ND Small Commercial and Industrial Customer Counts	Metrix Output	Contribution of each variable to the predicted value ("Trade Secret – BX" tab)
21-0668 DOC-15_Att K.xlsx	ND Large Commercial and Industrial Customer Counts	Trend Calc	Aggregated variables are on the tab "Disaggregated Data"
21-0668 DOC-15_Att L.xlsx	ND Public Street and Highway Lighting Customer Counts	Trend Calc	
21-0668 DOC-15_Att M.xlsx	ND Other Public Authority Customer Counts	Trend Calc	
21-0668 DOC-15_Att N_NON-PUBLIC.xlsx	SD Residential without Space Heat Customer Counts	Metrix Output	
21-0668 DOC-15_Att O_NON-PUBLIC.xlsx	SD Residential with Space Heat Customer Counts	Metrix Output	
21-0668 DOC-15_Att P_NON-PUBLIC.xlsx	SD Small Commercial and Industrial Customer Counts	Metrix Output	
21-0668 DOC-15_Att Q.xlsx	SD Large Commercial and Industrial Customer Counts	Trend Calc	
21-0668 DOC-15_Att R.xlsx	SD Public Street and Highway Lighting Customer Counts	Metrix Output	
21-0668 DOC-15_Att S_NON-PUBLIC.xlsx	WI Residential Customer Counts	Metrix Output	
21-0668 DOC-15_Att T.xlsx	WI Small Commercial and Industrial Customer Counts	Metrix Output	
21-0668 DOC-15_Att U.xlsx	WI Large Commercial and Industrial Customer Counts	Trend Calc	
21-0668 DOC-15_Att V_NON-PUBLIC.xlsx	WI Public Street and Highway Lighting Customer Counts	Metrix Output	

File Name	File Contents	File Type	Description
21-0668 DOC-15_Att W.xlsx	WI Other Public Authority Customer Counts	Metrix Output	
21-0668 DOC-15_Att X.xlsx	WI Interdepartmental Customer Counts	Trend Calc	
21-0668 DOC-15_Att Y.xlsx	MI Residential Customer Counts	Trend Calc	
21-0668 DOC-15_Att Z.xlsx	MI Small Commercial and Industrial Customer Counts	Trend Calc	
21-0668 DOC-15_Att AA.xlsx	MI Large Commercial and Industrial Customer Counts	Trend Calc	
21-0668 DOC-15_Att AB.xlsx	MI Public Street and Highway Lighting Customer Counts	Trend Calc	
21-0668 DOC-15_Att AC.xlsx	MI Other Public Authority Customer Counts	Trend Calc	
21-0668 DOC-15_Att AD.xlsx	MI Interdepartmental Customer Counts	Trend Calc	
21-0668 DOC-15_Att AE_NON-PUBLIC.xlsx	MN Residential without Space Heat Sales	Metrix Output	
21-0668 DOC-15_Att AF_NON-PUBLIC.xlsx	MN Residential with Space Heat Sales	Metrix Output	
21-0668 DOC-15_Att AG_NON-PUBLIC.xlsx	MN Small Commercial and Industrial Sales	Metrix Output	
21-0668 DOC-15_Att AH_NON-PUBLIC.xlsx	MN Large Commercial and Industrial Sales	Metrix Output	
21-0668 DOC-15_Att AI_NON-PUBLIC.xlsx	MN Public Street and Highway Lighting Sales	Metrix Output	
21-0668 DOC-15_Att AJ_NON-PUBLIC.xlsx	MN Other Public Authority Sales	Metrix Output	
21-0668 DOC-15_Att AK_NON-PUBLIC.xlsx	ND Residential without Space Heat Sales	Metrix Output	
21-0668 DOC-15_Att AL_NON-PUBLIC.xlsx	ND Residential with Space Heat Sales	Metrix Output	
21-0668 DOC-15_Att AM_NON-PUBLIC.xlsx	ND Small Commercial and Industrial Sales	Metrix Output	
21-0668 DOC-15_Att AN_NON-PUBLIC.xlsx	SD Residential without Space Heat Sales	Metrix Output	
21-0668 DOC-15_Att AO_NON-PUBLIC.xlsx	SD Residential with Space Heat Sales	Metrix Output	
21-0668 DOC-15_Att AP_NON-PUBLIC.xlsx	SD Small Commercial and Industrial Sales	Metrix Output	
21-0668 DOC-15_Att AQ_NON-PUBLIC.xlsx	WI Residential Sales	Metrix Output	
21-0668 DOC-15_Att AR_NON-PUBLIC.xlsx	WI Small Commercial and Industrial Sales	Metrix Output	
21-0668 DOC-15_Att AS_NON-PUBLIC.xlsx	MI Residential Sales	Metrix Output	
21-0668 DOC-15_Att AT_NON-PUBLIC.xlsx	MI Small Commercial and Industrial Sales	Metrix Output	
21-0668 DOC-15_Att AU.xlsx	NSP Peak Demand Model	Metrix Output	
21-0668 DOC-15_Att AV_NON-PUBLIC.xlsx	NSP MN Fcst	Organize/Adjustments	Organize and Adjustments files apply post regression adjustments such as calendarization
21-0668 DOC-15_Att AW.xlsx	NSP ND Fcst	Organize/Adjustments	
21-0668 DOC-15_Att AX.xlsx	NSP SD Fcst	Organize/Adjustments	
21-0668 DOC-15_Att AY.xlsx	NSP WI Fcst	Organize/Adjustments	
21-0668 DOC-15_Att AZ.xlsx	NSP MI Fcst	Organize/Adjustments	
21-0668 DOC-15_Att BA.xlsx	NSP Peak Fcst	Organize/Adjustments	
21-0668 DOC-15_Att BB.xlsx	Energy and Peak Summary	Summary	Summarizes and aggregates all results

B. Refer to the Company's response to part A above.

C. All customer count, energy sales, and peak demand models are estimated on monthly observations. Models from the Company's fall 2022 load forecast were estimated over the historical period from Jan 2007 to May 2022.

D. The peak outlook in responses to parts A through C above is a "base peak" definition adjusted for distributed solar generation.

E. Refer to the Company's response to part A above for Metrix output files containing disaggregated data.

A number of the attachments to this response include Trade Secret information, as marked, that is protected by the Minnesota Data Practices Act. That information has economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons and is subject to efforts by the Company to protect the information from public disclosure. Xcel Energy maintains this information as a trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. For this reason, we ask that the data be treated as not-public data pursuant to Minn. Stat. § 13.37, subd. 1(b).

Preparer: Benjamin Levine
Title: Energy Forecasting Analyst
Department: Sales Energy & Demand
Telephone: 651-558-1923
Date: February 14, 2023

Percent Error after Xcel's Forecast Adjustments

Forecast Vintage	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Oct-08	4.1%	8.5%	4.8%	6.6%	4.1%	7.0%	7.5%	9.1%	10.0%	12.1%	12.0%
Apr-09		5.8%	4.6%	3.9%	1.1%	3.7%	3.9%	5.2%	6.0%	8.0%	7.7%
Oct-09		-3.1%	3.2%	3.2%	1.0%	3.5%	3.7%	4.8%	5.4%	7.2%	6.7%
Apr-10			1.2%	1.5%	-0.4%	2.8%	3.6%	5.2%	6.0%	7.9%	7.7%
Jul-10			1.6%	3.7%	0.3%	2.9%	3.3%	4.4%	4.8%	6.2%	5.5%
Apr-11				1.5%	-1.4%	0.5%	0.5%	1.9%	2.5%	4.2%	3.7%
Sep-11				8.7%	-1.3%	0.1%	0.3%	1.5%	2.1%	3.6%	3.2%
Mar-12					-3.2%	-1.8%	-1.8%	-0.7%	-0.1%	1.5%	1.2%
Jul-12					2.3%	1.2%	1.2%	2.3%	2.6%	4.2%	3.5%
Mar-13						1.1%	0.6%	1.4%	1.6%	3.1%	2.5%
Jul-13						2.4%	2.2%	3.2%	3.5%	4.7%	3.9%
Sep-13						1.0%	0.7%	1.1%	1.5%	3.1%	2.5%
Mar-14							1.6%	2.1%	2.4%	3.8%	3.2%
Aug-14							-3.2%	1.9%	2.6%	4.2%	3.6%
Mar-15								1.3%	2.1%	3.8%	3.1%
Jul-15								0.8%	1.7%	3.4%	2.6%
Mar-16									-0.1%	1.6%	0.7%
Aug-16									-0.4%	1.1%	0.1%
Nov-16										1.0%	0.0%
Mar-17										1.6%	0.5%
Jul-17										1.1%	0.5%
Mar-18											-0.9%
Jul-18											-0.2%

Xcel Peak Demand Adjusted for Unknown DSM over achievements, loss of wholesales and Large Customer load, and CHP Generation

Weather Normal Peak Demand, MW

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Actual Weather Normal		**9,173**	**8,879**	**9,021**	**8,989**	**9,237**	**9,067**	**9,133**	**9,108**	**9,124**	**9,027**	**9,127**
Forecast Vintage	**Oct-2008**	9,552	9,631	9,451	9,581	9,613	9,698	9,819	9,935	10,039	10,121	10,221
	Apr-2009		9,390	9,439	9,342	9,339	9,400	9,492	9,584	9,675	9,749	9,830
	Oct-2009		8,606	9,308	9,275	9,333	9,386	9,473	9,547	9,620	9,674	9,743
	Apr-2010			9,130	9,122	9,205	9,319	9,465	9,577	9,675	9,742	9,826
	Jul-2010			9,169	9,319	9,262	9,327	9,438	9,509	9,564	9,590	9,629
	Apr-2011				9,120	9,108	9,110	9,176	9,280	9,356	9,409	9,467
	Sep-2011				9,772	9,119	9,074	9,159	9,245	9,312	9,355	9,420
	Mar-2012					8,941	8,903	8,972	9,045	9,111	9,163	9,236
	Jul-2012					9,452	9,180	9,239	9,318	9,364	9,402	9,450
	Mar-2013						9,163	9,186	9,233	9,270	9,305	9,354
	Jul-2013						9,285	9,338	9,403	9,440	9,456	9,479
	Sep-2013						9,162	9,194	9,210	9,259	9,303	9,356
	Mar-2014							9,281	9,303	9,346	9,373	9,418
	Aug-2014							8,841	9,281	9,359	9,406	9,453
	Mar-2015								9,230	9,316	9,373	9,412
	Jul-2015								9,178	9,284	9,330	9,369
	Mar-2016									9,112	9,174	9,193
	Aug-2016									9,088	9,122	9,133
	Nov-2016									(30)	9,119	9,129
	Mar-2017										9,173	9,170
	Jul-2017										9,123	9,176
	Mar-2018											9,042
	Jul-2018											9,111

Average Error (%) By			EnCompass	
Fcast Yr	**All**	**Mar '14 -**	**Fcast Adj**	
1	1.1%		**0.0%**	1.1%
2	1.6%		**0.0%**	1.6%
3	1.7%		**2.0%**	-0.3%
4	2.3%		**2.0%**	0.3%
5	3.0%		**2.0%**	1.0%
6	3.6%		**4.0%**	-0.4%
7	4.6%		**4.0%**	0.6%
8	5.9%		**6.0%**	-0.1%
9	7.7%		**6.0%**	1.7%
10	8.9%		**10.0%**	-1.1%
11	12.0%		**10.0%**	2.0%

14	10.9%	Fcast Too Low
115	89.1%	Fcast Too High
0	0.0%	Correct

Table 1

Xcel Forecast Vintage	Data Points	%	Data Points	%
2019v2.3	**Demand**		**Energy**	
Fcast Too Low	14	10.9	44	34.9
Fcast Too High	115	89.1	82	65.1
Correct	0	0.0%	0	0.0%

Table 2

Xcel Forecast Vintages	Data Points	%	Data Points	%
	Demand		**Energy**	
Fcast Too Low	18	8.6	57	27.9
Fcast Too High	192	91.4	147	72.1
Correct	0	0.0%	0	0.0%

Table 3

Xcel Forecast Vintages	Avg Ann Growth Rate %	
	Demand	**Energy**
2019v2.3 (2020-2034)	0.7	0.2
2022v1.0 (2022-2037)	0.3	0.3
2022v2.0 (2023-2038)	0.5	0.9

Percent Error after Xcel's Forecast Adjustments

Forecast Vintage	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Oct-08	-0.4%	3.0%	1.9%	2.0%	2.4%	3.4%	3.2%	4.4%	4.2%	5.9%	5.5%
Apr-09		2.8%	1.7%	1.9%	2.5%	3.9%	4.0%	5.4%	5.5%	7.5%	7.5%
Oct-09		0.5%	-0.7%	0.2%	1.3%	2.9%	3.1%	4.2%	4.2%	6.2%	6.3%
Apr-10			-0.9%	-0.4%	0.8%	2.2%	2.6%	3.8%	3.9%	5.6%	5.4%
Jul-10			-0.7%	-0.2%	0.8%	2.0%	2.4%	3.8%	4.0%	5.6%	5.4%
Apr-11				0.0%	0.7%	1.1%	1.3%	2.8%	3.0%	4.5%	4.0%
Sep-11				-0.4%	-0.2%	0.5%	0.4%	1.6%	1.5%	3.0%	2.5%
Mar-12					-0.4%	-0.7%	-1.3%	-0.3%	-0.3%	1.1%	0.5%
Jul-12					-0.8%	-0.8%	-1.4%	-0.5%	-0.6%	0.6%	0.1%
Mar-13						-0.3%	-1.3%	-0.5%	-0.7%	0.5%	0.0%
Jul-13						-0.3%	-1.3%	-0.5%	-0.7%	0.5%	0.0%
Sep-13						-0.3%	-1.7%	-1.2%	-1.5%	-0.4%	-1.0%
Mar-14							-1.0%	-0.6%	-1.0%	0.1%	-0.6%
Aug-14							-0.3%	1.1%	1.2%	2.8%	2.4%
Mar-15								1.6%	1.9%	3.6%	3.2%
Jul-15								0.7%	1.0%	2.5%	2.2%
Mar-16									0.3%	1.8%	0.7%
Aug-16										0.3%	-0.8%
Nov-16										0.2%	-0.9%
Mar-17										0.5%	-0.7%
Jul-17											-0.8%
Mar-18											-1.5%
Jul-18											

Xcel Energy Adjustments for Unknown DSM over achievements, loss of wholesales and Large Customer load, and CHP Generation
Weather Normal Energy, MWh

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Actual Weather Normal		**47,344,997**	**45,748,110**	**45,976,872**	**45,864,909**	**45,399,545**	**44,566,353**	**44,864,615**	**44,556,225**	**44,798,290**	**44,020,922**	**44,179,961**
Forecast Vintage	**Oct-2008**	47,154,554	47,128,738	46,862,714	46,775,747	46,471,214	46,084,671	46,294,040	46,507,685	46,698,650	46,625,093	46,627,210
	Apr-2009		47,008,176	46,766,915	46,750,610	46,553,617	46,292,162	46,656,592	46,968,762	47,270,624	47,320,749	47,485,252
	Oct-2009		45,959,368	45,636,851	45,952,322	45,996,124	45,877,061	46,256,305	46,445,324	46,688,745	46,749,576	46,943,301
	Apr-2010			45,583,769	45,703,887	45,779,899	45,562,342	46,015,555	46,245,671	46,558,619	46,465,138	46,571,268
	Jul-2010			45,674,965	45,778,108	45,768,035	45,469,971	45,942,419	46,240,175	46,595,433	46,501,949	46,543,839
	Apr-2011				45,876,028	45,710,561	45,060,263	45,451,406	45,798,832	46,141,831	46,005,923	45,950,469
	Sep-2011				45,685,895	45,302,964	44,799,061	45,033,964	45,261,654	45,491,770	45,321,178	45,284,127
	Mar-2012					45,198,851	44,268,056	44,299,366	44,439,836	44,668,403	44,508,984	44,419,670
	Jul-2012					45,020,580	44,210,964	44,218,908	44,337,503	44,531,354	44,306,335	44,215,986
	Mar-2013						44,436,966	44,299,134	44,349,389	44,505,186	44,251,445	44,159,172
	Jul-2013						44,436,966	44,299,134	44,349,389	44,505,186	44,251,445	44,159,172
	Sep-2013						44,430,201	44,106,890	44,021,960	44,138,599	43,859,480	43,741,372
	Mar-2014							44,398,828	44,306,362	44,352,050	44,074,304	43,913,618
	Aug-2014							44,742,499	45,029,854	45,331,080	45,242,063	45,226,663
	Mar-2015								45,286,170	45,669,222	45,589,615	45,579,951
	Jul-2015								44,884,051	45,225,866	45,143,288	45,160,042
	Mar-2016									44,947,965	44,796,694	44,493,389
	Aug-2016										44,159,314	43,810,728
	Nov-2016										44,128,758	43,769,023
	Mar-2017										44,247,326	43,866,159
	Jul-2017											43,843,861
	Mar-2018											43,526,427
	Jul-2018											

Average Error (%) By Forecast Year			
Fcast Yr	**All**	**EnCompass Fcast Adj**	
1	0.0%	**0.0%**	0.0%
2	0.0%	**0.0%**	0.0%
3	0.6%	**0.0%**	0.6%
4	1.0%	**0.0%**	1.0%
5	1.4%	**2.0%**	-0.6%
6	1.9%	**2.0%**	-0.1%
7	3.2%	**4.0%**	-0.8%
8	4.5%	**4.0%**	0.5%
9	5.7%	**4.0%**	1.7%
10	6.6%	**6.0%**	0.6%
11	5.5%	**6.0%**	-0.5%

44	34.9%	Fcast Too Low
82	65.1%	Fcast Too High
0	0.0%	Correct

Xcel Peak Demand Adjusted for Unknown DSM over achievements, loss of wholesales and Large Customer load, and CHP Generation
Weather Normal Peak Demand, MW

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Actual Weather Normal		9,173	8,879	9,021	8,989	9,237	9,067	9,133	9,108	9,124	9,027	9,127	9,092	8,729	8,814
Forecast Vintage	**Oct-2008**	9,552	9,631	9,451	9,581	9,613	9,698	9,819	9,935	10,039	10,121	10,221	10,306	10,423	10,524
	Apr-2009		9,390	9,439	9,342	9,339	9,400	9,492	9,584	9,675	9,749	9,830	9,886	9,989	10,061
	Oct-2009		8,606	9,308	9,275	9,333	9,386	9,473	9,547	9,620	9,674	9,743	9,787	9,879	9,941
	Apr-2010			9,130	9,122	9,205	9,319	9,465	9,577	9,675	9,742	9,826	9,885	9,987	10,053
	Jul-2010			9,169	9,319	9,262	9,327	9,438	9,509	9,564	9,590	9,629	9,646	9,692	9,715
	Apr-2011				9,120	9,108	9,110	9,176	9,280	9,356	9,409	9,467	9,507	9,586	9,666
	Sep-2011				9,772	9,119	9,074	9,159	9,245	9,312	9,355	9,420	9,468	9,544	9,610
	Mar-2012					8,941	8,903	8,972	9,045	9,111	9,163	9,236	9,284	9,370	9,426
	Jul-2012					9,452	9,180	9,239	9,318	9,364	9,402	9,450	9,484	9,559	9,616
	Mar-2013						9,163	9,186	9,233	9,270	9,305	9,354	9,389	9,466	9,531
	Jul-2013						9,285	9,338	9,403	9,440	9,456	9,479	9,498	9,551	9,590
	Sep-2013						9,162	9,194	9,210	9,259	9,303	9,356	9,390	9,420	9,449
	Mar-2014							9,281	9,303	9,346	9,373	9,418	9,436	9,471	9,497
	Aug-2014							8,841	9,281	9,359	9,406	9,453	9,507	9,530	9,528
	Mar-2015								9,230	9,316	9,373	9,412	9,480	9,507	9,526
	Jul-2015								9,178	9,284	9,330	9,369	9,438	9,475	9,495
	Mar-2016									9,112	9,174	9,193	9,249	9,276	9,295
	Aug-2016									9,088	9,122	9,133	9,201	9,209	9,234
	Nov-2016									(30)	9,119	9,129	9,194	9,197	9,220
	Mar-2017										9,173	9,170	9,212	9,231	9,225
	Jul-2017										9,123	9,176	9,188	9,226	9,216
	Mar-2018											9,042	8,989	8,977	8,960
	Jul-2018											9,111	9,095	9,089	9,068
	Mar-2019												9,158	9,147	9,154
	Jul-2019												9,057	9,057	8,975
	Mar-2020													8,929	8,880
	Jul-2020													8,562	8,728
	Mar-2021														8,929
	Jul-2021														8,943

Peak Demand Variance MW	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Oct-2008	379	752	430	591	376	631	686	827	915	1,094	1,094	1,213	1,695	1,710
Apr-2009		511	418	353	102	333	359	476	551	722	703	794	1,261	1,247
Oct-2009		(273)	287	286	96	319	340	439	496	647	616	694	1,150	1,127
Apr-2010			109	133	(32)	252	332	469	551	715	699	792	1,259	1,239
Jul-2010			148	330	25	260	304	401	440	563	502	554	963	901
Apr-2011				131	(129)	43	42	173	232	382	340	415	857	852
Sep-2011				783	(118)	7	26	137	188	328	293	376	815	796
Mar-2012					(296)	(164)	(162)	(63)	(13)	136	109	192	641	612
Jul-2012					215	113	106	211	240	375	323	391	831	802
Mar-2013						96	53	125	146	277	227	296	738	717
Jul-2013						218	205	295	316	428	352	405	822	776
Sep-2013						95	61	102	135	276	229	297	691	635
Mar-2014							147	196	222	346	291	343	743	683
Aug-2014							(292)	173	235	379	326	414	802	714
Mar-2015								122	192	346	285	387	779	712
Jul-2015								70	160	303	242	345	746	681
Mar-2016									(12)	147	66	157	548	481
Aug-2016									(36)	95	6	109	480	420
Nov-2016										92	2	102	468	406
Mar-2017										146	43	120	502	411
Jul-2017										96	49	95	497	402
Mar-2018											(85)	(103)	248	146
Jul-2018											(16)	2	360	254
Mar-2019												65	418	340
Jul-2019												(36)	328	161
Mar-2020													200	66
Jul-2020													(167)	(86)
Mar-2021														115
Jul-2021														129

Peak Demand
Variance △ %

Forecast Vintage

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Oct-2008	4.1%	8.5%	4.8%	6.6%	4.1%	7.0%	7.5%	9.1%	10.0%	12.1%	12.0%	13.3%	19.4%	19.4%
Apr-2009		5.8%	4.6%	3.9%	1.1%	3.7%	3.9%	5.2%	6.0%	8.0%	7.7%	8.7%	14.4%	14.2%
Oct-2009		-3.1%	3.2%	3.2%	1.0%	3.5%	3.7%	4.8%	5.4%	7.2%	6.7%	7.6%	13.2%	12.8%
Apr-2010			1.2%	1.5%	-0.4%	2.8%	3.6%	5.2%	6.0%	7.9%	7.7%	8.7%	14.4%	14.1%
Jul-2010			1.6%	3.7%	0.3%	2.9%	3.3%	4.4%	4.8%	6.2%	5.5%	6.1%	11.0%	10.2%
Apr-2011				1.5%	-1.4%	0.5%	0.5%	1.9%	2.5%	4.2%	3.7%	4.6%	9.8%	9.7%
Sep-2011				8.7%	-1.3%	0.1%	0.3%	1.5%	2.1%	3.6%	3.2%	4.1%	9.3%	9.0%
Mar-2012					-3.2%	-1.8%	-1.8%	-0.7%	-0.1%	1.5%	1.2%	2.1%	7.3%	6.9%
Jul-2012					2.3%	1.2%	1.2%	2.3%	2.6%	4.2%	3.5%	4.3%	9.5%	9.1%
Mar-2013						1.1%	0.6%	1.4%	1.6%	3.1%	2.5%	3.3%	8.5%	8.1%
Jul-2013						2.4%	2.2%	3.2%	3.5%	4.7%	3.9%	4.5%	9.4%	8.8%
Sep-2013						1.0%	0.7%	1.1%	1.5%	3.1%	2.5%	3.3%	7.9%	7.2%
Mar-2014							1.6%	2.1%	2.4%	3.8%	3.2%	3.8%	8.5%	7.8%
Aug-2014							-3.2%	1.9%	2.6%	4.2%	3.6%	4.6%	9.2%	8.1%
Mar-2015								1.3%	2.1%	3.8%	3.1%	4.3%	8.9%	8.1%
Jul-2015								0.8%	1.7%	3.4%	2.6%	3.8%	8.5%	7.7%
Mar-2016									-0.1%	1.6%	0.7%	1.7%	6.3%	5.5%
Aug-2016									-0.4%	1.1%	0.1%	1.2%	5.5%	4.8%
Nov-2016										1.0%	0.0%	1.1%	5.4%	4.6%
Mar-2017										1.6%	0.5%	1.3%	5.8%	4.7%
Jul-2017										1.1%	0.5%	1.0%	5.7%	4.6%
Mar-2018											-0.9%	-1.1%	2.8%	1.7%
Jul-2018											-0.2%	0.0%	4.1%	2.9%
Mar-2019												0.7%	4.8%	3.9%
Jul-2019												-0.4%	3.8%	1.8%
Mar-2020													2.3%	0.7%
Jul-2020													-1.9%	-1.0%
Mar-2021														1.3%
Jul-2021														1.5%

Average Error (%) By	
Fcast Yr	**All**
1	1.0%
2	1.5%
3	1.9%
4	2.7%
5	3.6%
6	4.4%
7	5.3%
8	6.4%
9	7.3%
10	8.5%
11	10.4%
12	13.0%
13	15.5%
14	19.4%

18	8.6%	Fcast Too Low
192	91.4%	Fcast Too High
0	0.0%	Correct

Xcel Energy Adjustments for Unknown DSM over achievements, loss of wholesales and Large Customer load, and CHP Generation
Weather Normal Energy, MWh

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Actual Weather Normal		47,344,997	45,748,110	45,976,872	45,864,909	45,399,545	44,566,353	44,864,615	44,556,225	44,798,290	44,020,922	44,179,961	43,705,197	42,512,296	43,237,071
Forecast Vintag	**Oct-2008**	47,154,554	47,128,738	46,862,714	46,775,747	46,471,214	46,084,671	46,294,040	46,507,685	46,698,650	46,625,093	46,627,210	46,618,319	46,641,769	46,569,306
	Apr-2009		47,008,176	46,766,915	46,750,610	46,553,617	46,292,162	46,656,592	46,968,762	47,270,624	47,320,749	47,485,252	47,510,557	47,615,424	47,631,281
	Oct-2009		45,959,368	45,636,851	45,952,322	45,996,124	45,877,061	46,256,305	46,445,324	46,688,745	46,749,576	46,943,301	46,986,991	47,167,093	47,267,222
	Apr-2010			45,583,769	45,703,887	45,779,899	45,562,342	46,015,555	46,245,671	46,558,619	46,465,138	46,571,268	46,575,333	46,812,035	46,765,038
	Jul-2010			45,674,965	45,778,108	45,768,035	45,469,971	45,942,419	46,240,175	46,595,433	46,501,949	46,543,839	46,447,964	46,556,890	46,428,139
	Apr-2011				45,876,028	45,710,561	45,060,263	45,451,406	45,798,832	46,141,831	46,005,923	45,950,469	45,882,530	45,876,083	45,821,236
	Sep-2011				45,685,895	45,302,964	44,799,061	45,033,964	45,261,654	45,491,770	45,321,178	45,284,127	45,221,786	45,186,382	45,097,262
	Mar-2012					45,198,851	44,268,056	44,299,366	44,439,836	44,668,403	44,508,984	44,419,670	44,262,569	44,161,240	43,958,974
	Jul-2012					45,020,580	44,210,964	44,218,908	44,337,503	44,531,354	44,306,335	44,215,986	44,151,921	44,144,057	44,040,187
	Mar-2013						44,436,966	44,299,134	44,349,389	44,505,186	44,251,445	44,159,172	44,092,985	44,072,318	43,964,263
	Jul-2013						44,436,966	44,299,134	44,349,389	44,505,186	44,251,445	44,159,172	44,092,985	44,072,318	43,964,263
	Sep-2013						44,430,201	44,106,890	44,021,960	44,138,599	43,859,480	43,741,372	43,663,334	43,516,122	43,188,831
	Mar-2014							44,398,828	44,306,362	44,352,050	44,074,304	43,913,618	43,798,766	43,648,398	43,234,568
	Aug-2014							44,742,499	45,029,854	45,331,080	45,242,063	45,226,663	45,306,441	45,276,174	44,964,032
	Mar-2015								45,286,170	45,669,222	45,589,615	45,579,951	45,735,514	45,742,874	45,496,695
	Jul-2015								44,884,051	45,225,866	45,143,288	45,160,042	45,400,947	45,487,743	45,263,746
	Mar-2016									44,947,965	44,796,694	44,493,389	44,769,095	44,765,358	44,482,172
	Aug-2016										44,159,314	43,810,728	43,929,159	43,904,164	43,766,254
	Nov-2016										44,128,758	43,769,023	43,853,750	43,774,886	43,637,401
	Mar-2017										44,247,326	43,866,159	43,997,770	43,853,723	43,548,451
	Jul-2017											43,843,861	43,790,066	43,866,891	43,422,019
	Mar-2018											43,526,427	43,085,042	42,932,311	42,441,400
	Jul-2018												43,381,342	43,239,657	42,652,412
	Mar-2019												43,619,183	43,291,777	42,699,196
	Jul-2019													42,756,416	42,028,344
	Mar-2020													42,560,896	42,168,870
	Jul-2020														41,014,631
	Mar-2021														42,163,298

Energy Variance MWh		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Forecast Vintag	**Oct-2008**	(190,443)	1,380,628	885,842	910,838	1,071,669	1,518,318	1,429,425	1,951,460	1,900,361	2,604,172	2,447,249	2,913,122	4,129,472	3,332,235
	Apr-2009		1,260,065	790,044	885,701	1,154,072	1,725,809	1,791,977	2,412,537	2,472,334	3,299,827	3,305,291	3,805,359	5,103,128	4,394,210
	Oct-2009		211,258	(340,021)	87,414	596,579	1,310,708	1,391,690	1,889,099	1,890,455	2,728,654	2,763,340	3,281,793	4,654,797	4,030,151
	Apr-2010			(393,103)	(161,021)	380,354	995,990	1,150,940	1,689,446	1,760,330	2,444,216	2,391,307	2,870,136	4,299,738	3,527,967
	Jul-2010			(301,907)	(86,801)	368,490	903,619	1,077,803	1,683,950	1,797,143	2,481,028	2,363,878	2,742,766	4,044,594	3,191,068
	Apr-2011				11,119	311,016	493,910	586,791	1,242,607	1,343,542	1,985,001	1,770,508	2,177,333	3,363,786	2,584,165
	Sep-2011				(179,014)	(96,581)	232,708	169,348	705,429	693,480	1,300,256	1,104,165	1,516,589	2,674,086	1,860,190
	Mar-2012					(200,694)	(298,297)	(565,249)	(116,389)	(129,887)	488,062	239,709	557,372	1,648,943	721,903
	Jul-2012					(378,966)	(355,389)	(645,708)	(218,722)	(266,936)	285,413	36,024	446,723	1,631,760	803,115
	Mar-2013						(129,387)	(565,481)	(206,836)	(293,104)	230,524	(20,789)	387,787	1,560,022	727,192
	Jul-2013						(129,387)	(565,481)	(206,836)	(293,104)	230,524	(20,789)	387,787	1,560,022	727,192
	Sep-2013						(136,152)	(757,725)	(534,265)	(659,691)	(161,442)	(438,589)	(41,863)	1,003,825	(48,240)
	Mar-2014							(465,788)	(249,863)	(446,239)	53,382	(266,344)	93,569	1,136,102	(2,503)
	Aug-2014							(122,117)	473,629	532,790	1,221,142	1,046,702	1,601,244	2,763,878	1,726,961
	Mar-2015								729,945	870,933	1,568,693	1,399,990	2,030,317	3,230,578	2,259,624
	Jul-2015								327,826	427,576	1,122,366	980,080	1,695,750	2,975,446	2,026,675
	Mar-2016									149,675	775,772	313,428	1,063,897	2,253,062	1,245,100
	Aug-2016										138,392	(369,234)	223,961	1,391,868	529,182
	Nov-2016										107,837	(410,938)	148,552	1,262,590	400,329
	Mar-2017										226,404	(313,803)	292,573	1,341,426	311,379
	Jul-2017											(336,100)	84,869	1,354,595	184,948
	Mar-2018											(653,534)	(620,155)	420,014	(795,671)
	Jul-2018												(323,856)	727,360	(584,659)
	Mar-2019												(86,014)	779,481	(537,876)
	Jul-2019													244,120	(1,208,728)
	Mar-2020													48,599	(1,068,202)
	Jul-2020														(2,222,440)
	Mar-2021														(1,073,774)

Energy Variance %

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Oct-2008	-0.4%	3.0%	1.9%	2.0%	2.4%	3.4%	3.2%	4.4%	4.2%	5.9%	5.5%	6.7%	9.7%	7.7%
Apr-2009		2.8%	1.7%	1.9%	2.5%	3.9%	4.0%	5.4%	5.5%	7.5%	7.5%	8.7%	12.0%	10.2%
Oct-2009		0.5%	-0.7%	0.2%	1.3%	2.9%	3.1%	4.2%	4.2%	6.2%	6.3%	7.5%	10.9%	9.3%
Apr-2010			-0.9%	-0.4%	0.8%	2.2%	2.6%	3.8%	3.9%	5.6%	5.4%	6.6%	10.1%	8.2%
Jul-2010			-0.7%	-0.2%	0.8%	2.0%	2.4%	3.8%	4.0%	5.6%	5.4%	6.3%	9.5%	7.4%
Apr-2011				0.0%	0.7%	1.1%	1.3%	2.8%	3.0%	4.5%	4.0%	5.0%	7.9%	6.0%
Sep-2011				-0.4%	-0.2%	0.5%	0.4%	1.6%	1.5%	3.0%	2.5%	3.5%	6.3%	4.3%
Mar-2012					-0.4%	-0.7%	-1.3%	-0.3%	-0.3%	1.1%	0.5%	1.3%	3.9%	1.7%
Jul-2012					-0.8%	-0.8%	-1.4%	-0.5%	-0.6%	0.6%	0.1%	1.0%	3.8%	1.9%
Mar-2013						-0.3%	-1.3%	-0.5%	-0.7%	0.5%	0.0%	0.9%	3.7%	1.7%
Jul-2013						-0.3%	-1.3%	-0.5%	-0.7%	0.5%	0.0%	0.9%	3.7%	1.7%
Sep-2013						-0.3%	-1.7%	-1.2%	-1.5%	-0.4%	-1.0%	-0.1%	2.4%	-0.1%
Mar-2014							-1.0%	-0.6%	-1.0%	0.1%	-0.6%	0.2%	2.7%	0.0%
Aug-2014							-0.3%	1.1%	1.2%	2.8%	2.4%	3.7%	6.5%	4.0%
Mar-2015								1.6%	1.9%	3.6%	3.2%	4.6%	7.6%	5.2%
Jul-2015								0.7%	1.0%	2.5%	2.2%	3.9%	7.0%	4.7%
Mar-2016									0.3%	1.8%	0.7%	2.4%	5.3%	2.9%
Aug-2016										0.3%	-0.8%	0.5%	3.3%	1.2%
Nov-2016										0.2%	-0.9%	0.3%	3.0%	0.9%
Mar-2017										0.5%	-0.7%	0.7%	3.2%	0.7%
Jul-2017											-0.8%	0.2%	3.2%	0.4%
Mar-2018											-1.5%	-1.4%	1.0%	-1.8%
Jul-2018												-0.7%	1.7%	-1.4%
Mar-2019												-0.2%	1.8%	-1.2%
Jul-2019													0.6%	-2.8%
Mar-2020													0.1%	-2.5%
Jul-2020														-5.1%
Mar-2021														-2.5%

Average Error (%) By Forecast Year	
Fcast Yr	**All**
1	-0.3%
2	-0.1%
3	0.5%
4	1.2%
5	1.8%
6	2.6%
7	3.1%
8	3.4%
9	4.0%
10	5.6%
11	7.4%
12	9.0%
13	9.7%
14	7.7%

57	27.9%	Fcast Too Low
147	72.1%	Fcast Too High
0	0.0%	Correct

Northern States Power Company
Electric Utility - State of Minnesota

AGR Energy 21-668

NSP System Annual Energy Forecasts MWh

	Forecast Versions					
	2019v2.3		2022v1.0		2022v2.0	
2019	43,456,701					
2020	43,061,970	-0.9%				
2021	42,606,809	-1.1%				
2022	42,471,834	-0.3%	42,919,537			
2023	42,262,626	-0.5%	42,955,891	0.1%	43203801.76	
2024	42,140,430	-0.3%	43,059,425	0.2%	42982148.83	-0.5%
2025	42,103,713	-0.1%	43,165,771	0.2%	42841290.01	-0.3%
2026	42,228,105	0.3%	42,964,345	-0.5%	42769105.53	-0.2%
2027	42,493,983	0.6%	42,743,686	-0.5%	42708633.77	-0.1%
2028	42,936,296	1.0%	42,617,702	-0.3%	42737232.1	0.1%
2029	42,700,049	-0.6%	42,361,329	-0.6%	42650519.27	-0.2%
2030	42,896,785	0.5%	42,129,463	-0.5%	42589109.92	-0.1%
2031	43,072,712	0.4%	41,941,706	-0.4%	42579292.75	0.0%
2032	43,533,978	1.1%	41,878,121	-0.2%	42731274.58	0.4%
2033	44,142,411	1.4%	41,765,756	-0.3%	42934762.59	0.5%
2034	45,016,323	2.0%	41,683,472	-0.2%	43293022.73	0.8%
2035	45,727,503	1.6%	42,244,053	1.3%	44297594.35	2.3%
2036	46,576,549	1.9%	43,684,844	3.4%	46135707.78	4.1%
2037	47,175,140	1.3%	44,899,563	2.8%	47733987.28	3.5%
2038	47,717,862	1.2%	45,860,142	2.1%	49076003.62	2.8%
2039	48,321,349	1.3%	47,008,038	2.5%	50597420.35	3.1%
2040	49,071,619	1.6%	48,074,752	2.3%	52048757.9	2.9%
2041	49,503,362	0.9%	49,076,169	2.1%	53438701.94	2.7%
2042	50,063,728	1.1%	50,104,284	2.1%	54837359.46	2.6%
2043	50,675,164	1.2%	51,098,218	2.0%	56146226.92	2.4%
2044	51,412,012	1.5%	52,176,592	2.1%	57533763.37	2.5%
2045	51,837,901	0.8%	53,170,469	1.9%	58879155.26	2.3%
2046	52,359,635	1.0%	54,160,125	1.9%	60244061.02	2.3%
2047	52,876,047	1.0%	55,161,883	1.8%	61599872.83	2.3%
2048	53,461,640	1.1%	56,253,616	2.0%	63043634.9	2.3%
2049			56,845,128	1.1%	64002611.31	1.5%
2050			57,424,118	1.0%	64943881.34	1.5%
2051			58,055,403	1.1%	65907403.82	1.5%
	2020-2034 AGR	0.2%				
	2022-2037 AGR			0.3%		
	2023-2038 AGR					0.9%

Northern States Power Company
Electric Utility - State of Minnesota

AGR Demand 21-668

NSP System Annual Demand Forecasts, MW

	Forecast Versions					
	2019v2.3		2022v1.0		2022v2.0 IR	
2019	9,054					
2020	9,058	0.0%				
2021	9,028	-0.3%				
2022	9,066	0.4%	9,039		9095.294895	
2023	9,097	0.3%	9,099	0.7%	9139.666065	
2024	9,108	0.1%	9,158	0.6%	9142.785652	0.0%
2025	9,154	0.5%	9,189	0.3%	9139.978822	0.0%
2026	9,219	0.7%	9,250	0.7%	9151.414739	0.1%
2027	9,313	1.0%	9,250	0.0%	9168.060721	0.2%
2028	9,396	0.9%	9,232	-0.2%	9172.551918	0.0%
2029	9,409	0.1%	9,200	-0.4%	9163.180232	-0.1%
2030	9,480	0.8%	9,170	-0.3%	9152.370855	-0.1%
2031	9,546	0.7%	9,138	-0.3%	9133.7152	-0.2%
2032	9,634	0.9%	9,103	-0.4%	9111.413917	-0.2%
2033	9,830	2.0%	9,081	-0.2%	9112.058354	0.0%
2034	10,033	2.1%	9,059	-0.2%	9122.235688	0.1%
2035	10,179	1.5%	9,130	0.8%	9228.874632	1.2%
2036	10,330	1.5%	9,320	2.1%	9448.332896	2.4%
2037	10,493	1.6%	9,510	2.0%	9670.383939	2.4%
2038	10,616	1.2%	9,659	1.6%	9852.690282	1.9%
2039	10,741	1.2%	9,825	1.7%	10051.26417	2.0%
2040	10,870	1.2%	9,952	1.3%	10208.45401	1.6%
2041	10,999	1.2%	10,087	1.4%	10374.86889	1.6%
2042	11,120	1.1%	10,219	1.3%	10536.56767	1.6%
2043	11,241	1.1%	10,329	1.1%	10673.48593	1.3%
2044	11,381	1.2%	10,436	1.0%	10803.13078	1.2%
2045	11,481	0.9%	10,548	1.1%	10942.49308	1.3%
2046	11,591	1.0%	10,662	1.1%	11084.0456	1.3%
2047	11,696	0.9%	10,765	1.0%	11214.8649	1.2%
2048	11,758	0.5%	10,865	0.9%	11340.24005	1.1%
2049			10,892	0.2%	11393.89452	0.5%
2050			10,916	0.2%	11444.84358	0.4%
2051			10,947	0.3%	11500.48583	0.5%
	2020-2034 AGR	0.7%				
	2022-2037 AGR			0.3%		
	2023-2038 AGR					0.5%