

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

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

IN THE MATTER OF XCEL ENERGY'S PETITION FOR  
APPROVAL OF ITS 2023 ANNUAL FUEL FORECAST  
AND MONTHLY FUEL COST CHARGES

MPUC Docket No. E002/AA-22-179  
CAH Docket No. 21-2500-40336

**DIRECT TESTIMONY AND ATTACHMENTS OF ANDREW GOLDEN**

**ON BEHALF OF**

**THE MINNESOTA DEPARTMENT OF COMMERCE  
DIVISION OF ENERGY RESOURCES**

**JULY 2, 2025**

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OAH DOCKET NO. 21-2500-40336

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1 **I. INTRODUCTION**

2 **Q. Would you state your name, occupation, and business address?**

3 A. My name is Andrew Golden. I am employed as a Public Utilities Financial Analyst by the  
4 Minnesota Commerce Department, Division of Energy Resources (Department). My  
5 business address is 85 7th Place East, Suite 280, St. Paul, Minnesota 55101-2198.

6  
7 **Q. What is your educational and professional background?**

8 A. I received a Bachelor of Arts degree with majors in political science and journalism from  
9 the University of Wisconsin-Madison in 2011. In 2020, I received a Master of Public  
10 Administration degree from the University of Washington-Seattle, with a focus in public  
11 finance and budgeting. I joined the Department in September 2022. Prior to joining the  
12 Department, I worked as a Financial Examiner with the Washington State Department of  
13 Financial Institutions (DFI).

14  
15 **Q. Please describe your regulatory experience.**

16 A. Since joining the Department, I have worked on numerous dockets across a variety of  
17 topics including rate cases, transmission riders, fuel adjustments, service area  
18 agreements, capital structure, tariff revisions, and depreciation.

19  
20 In my time with DFI, my work included leading regulatory safety and soundness  
21 examinations of Washington State-chartered commercial banks assessing various  
22 financial components including earnings, liquidity, capital, and interest rate risk by

1 reviewing financial statements, financial performance, internal controls, and compliance  
2 with state and federal banking regulations.

3  
4 **II. PURPOSE AND SCOPE**

5 **Q. What are your responsibilities in this proceeding?**

6 A. I reviewed the financial components of Northern States Power Co. d/b/a Xcel Energy's  
7 (Xcel) forced outage events at its Prairie Island Nuclear Generating Plant (PINGP or the  
8 Plant) for the period of October 2023 to March 2024. Specifically, my review focused on  
9 whether Xcel's estimated incremental power costs and avoided replacement power  
10 costs were "reasonable and prudent." My testimony does not address the underlying  
11 reasonableness or prudence of the utility's request to recover these costs, but to assess  
12 the financial aspects of the Company's recommended refund to customers.

13  
14 **Q. What is the scope of your direct testimony?**

15 A. My direct testimony addresses the following areas:

- 16 1) Background information relevant to this proceeding;
- 17 2) Review of Xcel's estimated energy replacement costs related to the Xcel  
18 system during the PINGP Outage; and
- 19 3) Review of Xcel's proposed adjustments to its energy replacement costs,  
20 including proposed adjustments related to avoided future replacement  
21 power costs, avoided future outage days, and historical performance.

1     **III. BACKGROUND INFORMATION RELEVANT TO THIS PROCEEDING**

2     **Q. In brief, what was the cause of the PINGP outage?**

3     A. On October 19, 2023, during work being carried out by the Company to replace  
4       underground power cables between a substation and the Plant, Xcel drilled through a  
5       bundle of direct current cables, causing Unit 1 of PINGP to shut down and extending a  
6       planned outage already in progress at the time at Unit 2 of the Plant.

7  
8     **Q. As a result of the incident, how long was the outage at Unit 1 of the Plant and how  
9       long did it extend the planned outage at Unit 2?**

10    A. The total outage time for Unit 1 due to the incident was 103 days, returning to service  
11       January 30, 2024. The incident added 57 days to Unit 2's planned outage, ending March  
12       1, 2024.<sup>1</sup>

13  
14    **Q. How did the Company incur energy replacement costs during the outage?**

15    A. Energy replacement costs are incurred by utilities when a generation asset (such as a  
16       nuclear power plant) goes offline for a scheduled or forced outage. Xcel is obligated to  
17       provide retail electric service to its customers. Therefore, when a generation asset goes  
18       offline, Xcel must purchase additional wholesale power from another source, such as its  
19       other generation assets, bilateral purchases from an independent power producer, or  
20       purchases from the Midcontinent Independent System Operator (MISO) energy market.

---

<sup>1</sup> Ex. XCEL- \_\_\_ at 6-7 (Krug Direct).

1 Correspondingly, Xcel also loses the ability to sell power for the unit on outage at  
2 wholesale into the regional market.

3  
4 **Q. What does the Company estimate its replacement power costs were as a result of the**  
5 **outage?**

6 A. Xcel estimates the amount to be approximately \$48.5 million on a Total Company basis,  
7 or \$34.3 million for the Minnesota Jurisdiction.<sup>2</sup>

8  
9 **Q. Can you briefly explain the difference between a “total company” and “Minnesota**  
10 **jurisdiction” basis?**

11 A. Because Xcel serves customers within Minnesota and also in other jurisdictions, it is  
12 necessary to distinguish its overall replacement powers costs (“total company”) and the  
13 amount of those costs that are applicable to Minnesota customers (“Minnesota  
14 jurisdiction”). This is accomplished using a jurisdictional allocator that is based on the  
15 portion of Xcel sales in Minnesota of all Xcel sales during the relevant period.

16  
17 **Q. Has the Commission determined these costs, resulting from the outage, were**  
18 **prudently incurred?**

19 A. The Commission, in its November 15, 2024 Order,<sup>3</sup> determined that Xcel’s imprudence  
20 caused the outage and referred the matter to the Minnesota Court of Administrative

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<sup>2</sup> Ex. XCEL-\_\_\_ at 16 (Detmer Direct).

<sup>3</sup> *In re Xcel Energy’s Petition for Approval of its 2023 Annual Fuel Forecast and Monthly Fuel Cost Charges*, Docket No. E002/AA-22-179, ORDER APPROVING 2023 FUEL-CLAUSE TRUE-UP REPORT, REQUIRING ADDITIONAL FILINGS, FINDING IMPRUDENCE, AND NOTICE OF AND ORDER FOR HEARING at 11 (Nov. 15, 2024) (eDocket No. [202411-211999-01](#)).

1 Hearings to determine the appropriate refund amount due to the Company's lack of  
2 prudence.

3  
4 **Q. Does the Company contend its refund amount to Minnesota ratepayers should be**  
5 **lower than the \$34.3 million referenced above?**

6 A. Yes, the Company recommends the refund amount should be reduced to \$5.8 million  
7 (MN Jurisdiction).<sup>4</sup>

8  
9 **Q. How does the Company support this recommendation?**

10 A. Xcel recommends three adjustments that reduce the refund amount. First, the  
11 Company states the replacement of the damaged cables would have had to occur at a  
12 future time. Xcel theorizes that the cables would have either required replacement  
13 during a subsequent license renewal for the Plant or that the cables would have almost  
14 certainly failed in the future given their age and condition. Xcel says that replacing them  
15 during the outage avoided additional future estimated replacement power costs of  
16 \$27.2 million (\$21.0 MN Jurisdictional).<sup>5</sup>

17 Second, the Company states it completed work during the outage that it had  
18 planned to complete during future planned outages, and thus averted approximately 8  
19 future outage days equivalent to avoided replacement power costs of \$2.4 million (\$1.8  
20 million MN Jurisdictional).

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<sup>4</sup> Ex. XCEL-\_\_\_ at 24 (Detmer Direct); Note that Mr. Detmer provided revised dollar amounts and outage length estimates in an errata filing. See Errata to the Direct Testimony and Schedule 2 of Nicholas Detmer at 18 (June 27, 2025) (eDocket No. [20256-220369-01](#)).

<sup>5</sup> Ex. XCEL-\_\_\_ at 18 (Errata).

1                   Lastly, Xcel states the Plant’s historical performance relative to the industry  
2 median has benefited Minnesota ratepayers and propose to reduce the \$11.4 (MN  
3 Jurisdictional) refund calculated after the two preceding adjustments above by 49%, for  
4 a total customer refund of \$5.8 million (MN Jurisdictional). My testimony below  
5 addresses these recommended adjustments and the initial replacement power cost  
6 estimate in further detail below.

7  
8 **IV. ASSESSMENT OF ESTIMATED ENERGY REPLACEMENT COSTS**

9 **Q. How should the amount of energy replacement costs associated with the PINGP**  
10 **outage be determined?**

11 A. The amount of energy replacement costs associated with the PINGP outage should be  
12 determined according to the additional energy costs Xcel’s customers paid due to the  
13 outage. That amount should be determined by comparing what Xcel’s energy costs  
14 would have been had the outage not occurred to what the costs actually were.

15  
16 **Q. How did the Company calculate its estimated \$34.3 million in energy replacement**  
17 **costs (MN jurisdictional) related to the outage?**

18 A. Xcel utilized its PLEXOS modeling software to approximate the actual operations for the  
19 outage period, creating a scenario mirroring the period’s available energy supply, fuel  
20 costs, customer loads, and MISO market prices, and calculated the total system costs for  
21 this “base case.” The Company then created a modified scenario (“change case”) from  
22 this case where PINGP was available, as if there had been no outage, and computed the

1 difference between the costs under this non-outage scenario to the outage scenario.

2 According to Xcel, the resulting difference is the \$48.5 million (\$34.3 million Minnesota  
3 Jurisdiction).<sup>6</sup>

4  
5 **Q. Is it possible to determine an exact cost for replacement energy resulting from the**  
6 **outage?**

7 A. No. Due to the need to use hypotheticals when modeling alternative scenarios that did  
8 not actually occur to develop these estimates, it is not possible. The modeling and the  
9 Company's estimate represent an approximation of the replacement energy costs based  
10 on the available data.

11  
12 **Q. Does the Department have any questions or concerns regarding the Company's**  
13 **estimated replacement energy costs for the outage period?**

14 A. Upon review of the modeling provided by the Company, the Department identified the  
15 Company's change case assumes that the MISO energy market would have been  
16 unchanged from the base case, despite PINGP's availability. Had the PINGP facility not  
17 experienced the outage, as Xcel is attempting to model, PINGP-generated energy likely  
18 would have caused MISO market changes, resulting in a different estimate of energy  
19 replacement costs from what the Company provided. The Department requests the  
20 Company to respond to this concern.

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<sup>6</sup> Ex. XCEL- \_\_\_ at 16 (Detmer Direct).

1 **V. REVIEW OF XCEL'S RECOMMENDED ADJUSTMENTS TO ITS ESTIMATED ENERGY**  
2 **REPLACEMENT COSTS**

3 **Q. Does Xcel recommend adjustments be made to its estimated \$34.3 million**  
4 **replacement power cost refund to Minnesota customers?**

5 A. Yes. As introduced above, the Company asserts it is entitled to three adjustments  
6 totaling \$28.5 million (MN Jurisdictional) to its refund calculation:

7 1) Avoided additional future replacement power costs of \$27.2 million (\$21.0  
8 MN Jurisdictional);

9 2) Avoided future outage days equivalent to \$2.4 million (\$1.8 million MN  
10 Jurisdictional) of replacement power costs; and

11 3) An adjustment to account for the Plant's historical performance, applying a  
12 51% "performance differential" to the \$11.4 million (MN Jurisdictional)  
13 subtotal after the adjustments above, reducing the total recommended  
14 customer refund to \$5.8 million – in effect a \$5.6 million adjustment.

15 I review each of these adjustments below.

16  
17 A. *AVOIDED FUTURE REPLACEMENT POWER COSTS ADJUSTMENT*

18 **Q. What is the basis for Xcel's proposed adjustment related to avoided future**  
19 **replacement power costs resulting from the outage?**

20 A. As detailed by Company witnesses Bible<sup>7</sup> and Hiser,<sup>8</sup> during work to replace the cables  
21 Xcel found many of the cables and their "jacket" casings were already damaged or

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<sup>7</sup> Ex. XCEL-\_\_\_\_, CRB-D-2 at 3 (Bible Direct).

<sup>8</sup> Ex. XCEL-\_\_\_\_, ALH-D-2 at 4-5 (Hiser Direct) .

1 degraded. Because of this, the Company contends that the cables may have otherwise  
2 failed had the October 2023 incident not occurred or that the condition of the cables  
3 possibly could have been identified during a subsequent license renewal (SLR)  
4 inspection, in which inspectors would have sampled a portion of the cables and may  
5 have discovered the condition of the cables. Xcel estimates a 20% chance of the  
6 degraded condition being identified during the SLR.<sup>9</sup>

7 As a result of the incident, the Company was able to identify the degraded  
8 condition and replace the cables before these alternate cases occurred. Because of this,  
9 Xcel states it avoided future replacement power costs of \$27.2 million (\$21.0 million MN  
10 Jurisdictional), which it believes should be credited as an adjustment to the \$34.3  
11 million Minnesota replacement energy costs customer refund established above.

12  
13 **Q. Under what conditions would the Company have incurred increased replacement**  
14 **power costs?**

15 A. The Company theorized about three scenarios where cable conditions were uncovered  
16 under other circumstances — cable failure or SLR inspection — and developed three  
17 cases to model and calculate avoided replacement power costs:

- 18 1) Case 1 entails the cable condition being identified as part of the Company's  
19 SLR inspection and replaced accordingly. Xcel estimates in this scenario, the  
20 Plant would have experienced an additional 93 outage days. In effect, the  
21 Company believes replacement as a result of the incident rather than as a

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<sup>9</sup> *Id.* at 17.

1 result of SLR inspection avoided 93 outage days, which it values as \$27.2  
2 million (\$21.0 million MN Jurisdictional) in avoided replacement power costs.  
3 The Company also states that had the cable intermittently or gradually failed,  
4 and the issue was identified because of this, avoided replacement costs  
5 would be the same as this Case 1 estimate.<sup>10</sup>

6 2) Case 2 describes a scenario where cable failure occurs while both PINGP  
7 units were in operation, resulting in a dual reactor trip. The Company  
8 estimates in this scenario the Plant would have experienced an additional  
9 208 outage days, valuing this as \$67.2 million (\$51.98 million MN  
10 Jurisdictional) in avoided replacement power costs.<sup>11</sup>

11 3) Case 3 represents a scenario in which cable failure occurred while one unit  
12 was in a planned refueling outage, with the online reactor tripped during the  
13 failure. Xcel estimates under this case the Plant would have experienced an  
14 additional 196 outage days, and comparing to this hypothetical avoided  
15 \$69.6 million (\$53.8 million MN Jurisdictional) replacement power costs.<sup>12</sup>

16  
17 **Q. How did the Company calculate these estimated avoided replacement power costs?**

18 A. For Case 1, Xcel assumed cable replacement during a planned refueling outage at Unit 2  
19 in 2029, executed similarly to replacement during the actual outage following the  
20 incident in 2023-2024. For Cases 2 and 3, the Company used the actual Unit 1 outage

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<sup>10</sup> Ex. XCEL-\_\_\_\_, NJD-D-2 at 2-4 (Detmer Direct); Ex. XCEL-\_\_\_\_ (Errata) at 18 and 23.

<sup>11</sup> *Id.* at 19, 20 and 23.

<sup>12</sup> *Id.* at 23.

1 time resulting from the 2023 incident, and applied a similar framework to Unit 2,  
2 resulting in the total estimated outage time, which it also projected to perform in 2029.  
3 Using these outage scenarios, the Company again used its PLEXOS modeling software to  
4 estimate the avoided replacement power costs for each case.

5  
6 **Q. Why did Xcel apply Case 1 as its avoided future replacement power costs adjustment**  
7 **rather than Case 2 or Case 3?**

8 A. The Company states it was applied as the most conservative case for avoided outage  
9 days and resultant replacement power costs.<sup>13</sup> Additionally, I note that it is not clear  
10 that Xcel would be entitled to recover replacement power costs during Case 2 or Case 3.  
11 Given the age and degradation of the cable, it is not clear that it would be prudent to  
12 wait until a cable failure to replace it.

13  
14 *B. AVOIDED FUTURE OUTAGE DAYS ADJUSTMENT*

15 **Q. What is the basis for Xcel’s proposed adjustment related to avoided future outage**  
16 **days?**

17 A. In brief, Xcel states it completed work during the outage that it had planned to carry out  
18 during a later planned outage. Because it “took advantage” of the outage to do this  
19 work, it saved time from future outages, thus saving ratepayers the costs for  
20 replacement power costs during those outages. Xcel determined it avoided

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<sup>13</sup> *Id.* at 6.

1 approximately 8.1 future outage days due to this work, resulting in avoided replacement  
2 power costs of \$2.4 million (\$1.8 million MN Jurisdiction).<sup>14</sup>

3  
4 **Q. How did the Company determine the number of future outage days it avoided?**

5 A. The Company provided details regarding the future planned work it completed during  
6 the outage, when the work started and ended, and the estimated labor hours for each  
7 work order. It then added the estimated labor hours for all of these work orders—6,036  
8 for Unit 1 and 2,469 for Unit 2—to estimate 8,505 in total labor hours. The Company  
9 then divided its total outage-related labor hours during the outage of 141,796 by the  
10 135 total outage days to calculate 1,050 labor hours per outage day. Finally, they  
11 divided the 8,505 in labor hours for the future work it completed by the 1,050 labor  
12 hours per outage day figure to determine the 8.1 future outage days avoided.<sup>15</sup>

13  
14 **Q. How did Xcel calculate the avoided replacement power costs as a result of its 8.1  
15 estimated avoided future outage days?**

16 A. The Company used the replacement power costs from the planned outage in Case 1  
17 described above divided by the estimated outage days to determine a daily rate. Xcel  
18 then multiplied this daily rate by its estimated 8 avoided outage days to calculate the  
19 \$2.4 million (\$1.8 million MN Jurisdictional) in avoided replacement power costs.

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<sup>14</sup> Ex. XCEL-\_\_\_\_, CRB-D-2 at 4 (Bible Direct).

<sup>15</sup> Ex. XCEL-\_\_\_\_, NJD-D-2 at 987-989 (Detmer Direct) (DOC IR No. 35 – Supplement, Attachment B).

1 **Q. When was this work described by the Company initially planned to have been**  
2 **completed?**

3 A. The bulk of the work completed on Unit 1 was initially planned for August 2024 through  
4 March 2025. The majority of the work completed on Unit 2 was initially planned for  
5 February 2024 and October 2025.

6  
7 **Q. The work completed during the outage was for the most part planned for time periods**  
8 **which have since past. Did the Company, in fact, see approximately 8.1 fewer outage**  
9 **days resulting from the work being completed early?**

10 A. No. In response to information request to the Company, Xcel reported its future outages  
11 were shortened only by approximately 2.2 outage days a result of this work.<sup>16</sup>

12  
13 **Q. Using the Company's estimates for the avoided replacement power costs of 8.1**  
14 **outage days, what would be the estimated avoided replacement power costs for 2.2**  
15 **outage days?**

16 A. Converting the \$1.8 million in estimated avoided replacement power costs for 8.1  
17 outage days prevented in a future outage to 2.2 outage days actually prevented per the  
18 Company would result in estimated avoided replacement power costs of \$499,892 (MN  
19 Jurisdictional).<sup>17</sup>

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<sup>16</sup> Ex. DOC-\_\_\_\_, ARG-D-1 at 2 (Golden Direct) (Xcel's response to OAG IR 9).

<sup>17</sup>  $(2.2 \text{ days} \div 8.1 \text{ days}) \times (\$1,840,513 \text{ avoided replacement power costs for } 8.1 \text{ days}) = \$499,892$

1 **Q. What adjustment do you recommend for avoided replacement power costs due to**  
2 **work completed during the PINGP outage that was initially planned for future**  
3 **outages?**

4 A. Because the Company avoided 2.2 future planned outage days-worth of work during the  
5 PINGP outage, I recommend that Xcel's proposed offset be reduced from \$1.8 million to  
6 \$499,892 (MN Jurisdictional) to account for avoided replacement power costs resulting  
7 from this work.

8  
9 C. *HISTORICAL PERFORMANCE ADJUSTMENT*

10 **Q. What is the basis for Xcel's proposed adjustment related to the historical performance**  
11 **of the Plant?**

12 A. The Company contends that the PINGP facility's strong performance relative to industry  
13 peers has benefited Minnesota customers and in effect saved them millions in costs. To  
14 support this claim, Xcel provided data from the five-year period from 2018 through 2022  
15 showing PINGP had fewer trips-per-unit, higher average station capacity factor, longer  
16 uninterrupted service, and fewer offline hours than industry average.<sup>18</sup> Because of this,  
17 the Company states the Plant's performance, including the PINGP outage in the instant  
18 docket, should be considered relative to industry peers rather than a "standard of  
19 perfection."<sup>19</sup>

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<sup>18</sup> Ex. XCEL-\_\_\_\_, ADK-D-2 at 5-6 (Krug Direct).

<sup>19</sup> *Id.* at 9-10.

1 **Q. How did the Company propose to adjust the refund to account for historical**  
2 **performance?**

3 A. The Company proposes to apply a “performance differential” of 51 percent to the  
4 customer refund after the proposed adjustments described above are applied to the  
5 customer refund.<sup>20</sup>

6  
7 **Q. How did the Company determine the multiplier it used to calculate the historical**  
8 **performance adjustment?**

9 A. Xcel provided Nuclear Energy Institute data comparing its 2018 to 2022 outage hours at  
10 PINGP Units 1 and 2 to industry median. The data shows the outages at the two units  
11 resulted in PINGP outage days exceeding the industry median outage days by 51%,<sup>21</sup>  
12 primarily due to the outage discussed in the instant docket. The Company explained  
13 that because the PINGP facility had exceeded the industry median outage hours by 51%,  
14 49% of the net costs should be removed to adjust for past historical performance of the  
15 PINGP facility, in effect adjusting the Company’s outage hours down to industry  
16 median.<sup>22</sup> That is, the \$11.4 million (MN Jurisdictional) refund amount the Company  
17 proposes, which was adjusted down from the initial \$34.3 million refund amount, be  
18 multiplied by 0.51 to calculate Xcel’s final proposed \$5.8 million customer refund.

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<sup>20</sup> Ex. XCEL-\_\_\_ at 24 (Detmer Direct).

<sup>21</sup> Ex. XCEL-\_\_\_, NJD-D-3 (Detmer Direct).

<sup>22</sup> Ex. XCEL-\_\_\_ at 24 (Detmer Direct).

1 **Q. Do you find Xcel's multiplier to be reasonable?**

2 A. The Department requests more information from Xcel as to why it would be reasonable  
3 to use a historical performance multiplier should be used and, if such a multiplier should  
4 be used, why the proposed timeframe for past historical performance is appropriate.  
5 The Company claims its past historical performance has benefited ratepayers and  
6 should receive credit for the Plant's sound operations, though the incident and resulting  
7 outage itself has caused its performance to exceed median industry outage hours. Put  
8 differently, Xcel arbitrarily selected a timeframe to compare itself to the industry and  
9 then despite performing worse than the industry median used that performance to  
10 justify a smaller refund. In short, the Company is effectively requesting that Prairie  
11 Island be treated as a median plant rather than a poor performer.

12  
13 **Q. How did the Company select the timeframe that it proposed using to judge PINGP's**  
14 **past historical performance?**

15 A. The Company did not explain why 2018 to 2022 would be an appropriate lookback  
16 period. Reviewing historical performance data, PINGP's average annual capacity factor  
17 was higher from 2018 to 2022 than it had been at any other point for which data is  
18 available, with the lowest capacity factor from the Company's proposed timeframe  
19 exceeding the highest average capacity factor from all other years.<sup>23</sup> For example, while  
20 Xcel noted that PINGP achieved an average capacity factor of 95% from 2018 to 2022, it  
21 only achieved average capacity factors of 77%, 86%, and 91% in the three years

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<sup>23</sup> Ex. DOC-\_\_\_, ARG-D-2 (Golden Direct) (Xcel's Response to DOC IR 48).

1 preceding that time frame.<sup>24</sup> This raises concerns that Xcel selected the proposed  
2 timeframe to maximize the value of the proposed adjustment rather than for any  
3 principled reason.  
4

5 **Q. Why did the capacity factor of PINGP improve starting in 2018?**

6 A. The Company did not provide testimony in this docket addressing the improvement in  
7 performance which started in 2018. A review of other filings the Company has made,  
8 however, suggest that capital investments over the past decade are the primary source  
9 of the Plant's improved performance.<sup>25</sup> Postponement of maintenance during the  
10 COVID-19 pandemic may have also contributed to the reduced offline hours at PINGP  
11 during the Company's proposed time frame for historical performance.<sup>26</sup>  
12

13 **VI. SUMMARY OF RECOMMENDATIONS**

14 **Q. Based on your investigation, what do you recommend?**

15 A. To summarize, I recommend:

- 16 1. The Company respond to the Department's position that its modeling of energy  
17 replacement costs associated with the outage should show MISO market  
18 changes and thus different estimated energy replacement costs than those

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<sup>24</sup> Ex. XCEL-\_\_\_ at 4 (Krug Direct); Ex. DOC-\_\_\_, ARG-D-2 (Golden Direct) (Xcel's Response to DOC IR 48).

<sup>25</sup> See, e.g. Ex. DOC-\_\_\_, ARG-D-3 at 2 (Golden Direct) (Docket No. E002/AA-19-293, Xcel 2020 Annual Fuel Forecast and Monthly Fuel Cost Charges); Ex. DOC-\_\_\_, ARG-D-4 at 2 (Golden Direct) (Docket No. E002/CN-24-68, Prochaska Direct).

<sup>26</sup> Ex. DOC-\_\_\_, ARG-D-5 at 2-3 (Golden Direct) (Docket No. E002/GR-21-630, Gardner Direct).

1 provided by the Company in the “change case” in which the outage did not  
2 occur.

3 2. The Company’s proposed offset for avoided replacement power costs due to  
4 work completed during the outage be reduced from \$1,828,918 to \$499,892.

5 3. The Company provide additional information as to why it would be reasonable to  
6 use a historical performance multiplier and, if such a multiplier should be used,  
7 why the proposed timeframe for past historical performance is appropriate.

8

9 **Q. Have you completed your direct testimony?**

10 A. Yes.

- Not-Public Document – Not For Public Disclosure  
 Public Document – Not-Public Data Has Been Excised  
 Public Document

Xcel Energy Information Request No. 9  
Docket No.: E002/AA-22-179  
Response To: Minnesota Office of the Attorney General  
Requestor: Judy Sigal  
Date Received: June 2, 2025

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Question:

Reference:

- Detmer Direct at 20, which states, “By pulling forward these projects from planned future outages, customers received a measurable benefit by avoiding future incremental power costs associated with those future outages.”
  - Detmer Direct Schedule 2, pages 9-10 (listing pulled-forward work)
  - Detmer Direct Schedule 2, page 11 (calculating outage days for pulled-forward work)
- A. Explain the relationship between an outage day and a calendar day.
- B. Did pulling forward work from planned future outages lengthen the outage in this case? If not, why not? If so, by how many calendar days? Explain how the calendar days were calculated and provide the calculation.
- C. Did pulling forward work from planned future outages shorten the planned future outages? If so, by how many calendar days? Explain how the calendar days were calculated and provide the calculation.
- D. For each planned future outage listed in Detmer Direct Schedule 2 at 9–10 (i.e., in Column 3), provide:
1. The purpose(s) of the planned future outage that pulled-forward work was originally scheduled for (e.g., refueling, maintenance, upgrades, inspections).
  2. Whether the planned future outage was avoided in its entirety by pulling forward work to the outage in this case.
  3. If the planned future outage was not avoided in its entirety, the actual duration of the planned future outage in calendar days (or estimated duration if the planned future outage has not yet occurred).
  4. If the planned future outage was not avoided in its entirety, the details of any other work scheduled for the planned future outage that was not pulled forward, including the actual or estimated number of labor hours associated with that other work.
- E. Identify each planned outage at Unit 1 or Unit 2 for the period from January 1, 2015 to date. For each planned outage, provide:

1. The start date;
2. The purpose of the outage;
3. Whether any cables were replaced during the outage;
4. The duration of the outage in calendar days; and
5. The total number of internal and contract labor hours associated with the outage.

Any responsive documents must be provided in their unlocked native format with all formulas and links intact.

Response:

- A. An outage day is equivalent to a 24-hour period, and it is specifically a reference to all of the outage-specific activities going on during that day. The first outage day, for example, starts from the time that the breaker opens and the unit comes offline to 24 hours after that specific activity.
- B. No, pulling this work forward did not increase the length of the outage. The critical path work (i.e., work that drove the outage duration) was the cable replacement work, and in particular the testing. This additional outage time provided the opportunity to perform additional work that was scheduled in the future and compatible with the critical path work.

In terms of how the outage days were calculated to account for this pulled-forward work, this calculation was previously discussed and provided in the Direct Testimony of Company witness Nicholas Detmer (Detmer Direct), Schedule 2 pages 5 and 989. First, we determined the average labor hours worked during one outage day by dividing the total approximate hours worked over the course of the outage by the total outage days (141,796 divided by 135 equals 1,050 hours). The total approximate labor hours of the work that was pulled forward into the outage was 8,505 labor hours. This number was divided by the average labor hours worked per outage day to arrive at 8.1 outage days for pulled forward work.

- C. Typically refueling activities and major projects drive outage schedules (i.e. critical path projects). For the work pulled forward that required a dual unit shutdown, this was critical path and did avoid having to shut down a unit while in a future refueling outage. The combined approximate labor hours for this dual unit shutdown work is 2,272 labor hours. Divided by the 1,050 average daily labor hours worked for 1 outage day, this work reduced the future outage by approximately 2.2 outage days. See Detmer Direct, Schedule 2 page 3. The rest of the pulled forward work was not critical path, so it likely would not have changed the total length of any future outage(s). The benefit of pulling this

work forward is improved plant reliability and lowered risk for potential future outages, derates, or other online or outage non-critical path maintenance.

D. The Company assumes this question is referring to column 2 of Detmer Direct Schedule 2 at 987-988, which identifies the future planning from which work was pulled forward. The Company responds to subparts 1-4 in Table 1 below, which identifies each of the future planned outages or workstreams from which work was pulled forward.

**Table 1**

When Work Was Otherwise Scheduled to Take Place (future)	Purpose	Avoided in Its Entirety?	Actual Duration	Other Work & Duration
1R34 - 9/2024	Refueling and Baffle Former Bolt/Clevis Bolt Replacement Project	No	119 outage days	RCP seal replacements; control valve repair, Ovation software correction, single point vulnerability risk elimination on feedwater system, control damper inspection, circulating water pump motor troubleshooting, and hundreds of other outage activities/tasks (162,244 labor hours)
Online <sup>1</sup> - WW2402 (2nd week of January 2024)	Replace circulating water valve and pipe	Yes	98 labor hours	N/A
Online - Pre 1R34 (August 2024)	Outage preparation including solenoid valve replacement and control valve repair	Yes	284 labor hours	N/A
Online ; Winter 2024	Non-destructive examination of the motor driven cooling water pump baseplate	Yes	8 labor hours	N/A
Online ; Q1 2025	Cooling water strainer recurring inspection and maintenance; solenoid valve replacement	Yes	253 labor hours	N/A
On dual unit forced outage list	Pipe replacement on cooling water system	Yes	1,820 labor hours	None
Online; Q1 2025 (preference for dual unit outage)	plant screenhouse stop log rail guide inspection	Yes	452 labor hours	N/A
Online ; Q2 2025 (derate required)	Condenser in and outer pass cleaning	Yes	674 labor hours	N/A
2/5/24 (WW2405)	Switchyard relay actuation and inspection, replace bird spikes near transformer; electrical inspection and maintenance on Unit 2 auxiliary and main transformer and breaker internal inspection	Yes	1,927 labor hours	N/A

<sup>1</sup> “Online” work refers to planned future work that would occur online but would not require a unit shutdown.

When Work Was Otherwise Scheduled to Take Place (future)	Purpose	Avoided in Its Entirety?	Actual Duration	Other Work & Duration
Q1 2024	Cooling water strainer and breaker inspection; solenoid valve replacement	Yes	137 labor hours	N/A
Online D6 Diesel OOS Window - Q1 2025	Diesel maintenance window	Yes	162 labor hours	N/A
2R34 (10/2025)	Refueling outage	No	Planned 30 outage days	Refueling and outage maintenance and testing activities (final scoping is still in progress- early estimated labor hours 55,000)

E. The Company responds to subparts 1-5 in Table 2 below, which identifies each planned outage at Unit 1 or Unit 2 for the period from January 1, 2015 to date.

**Table 2**

Outage Start Date	Outage Purpose	Cables Replaced? Y/N	Planned Outage Duration in Days	Actual Duration in Outage Days	Planned Labor Hours	Estimated Labor Hours <sup>2</sup>
1/26/2015	Unit 1 Maintenance Outage for 12 Reactor Coolant Pump Seal Replacement and Flushing	N	N/A	16.21	2,760	N/A
4/7/2015	Unit 1 Maintenance Outage for 12 Reactor Coolant Pump Seal Replacement and Flushing	N	N/A	32.02	2,958	N/A
10/17/2015	Unit 2 Cycle 29 Refueling Outage	N	34.63	49.72	102,694	147,443
10/15/2016	Unit 1 Cycle 30 Refueling Outage	Y	35	36.68	94,764	99,313
10/13/2017	Unit 2 Cycle 30 Refueling Outage	Y	28.25	37.86	76,026	101,888
9/21/2018	Unit 1 Cycle 31 Refueling Outage	Y	35.67	34.80	105,198	102,632
10/28/2019	Unit 2 Cycle 31 Refueling Outage	Y	25	23.20	51,774	48,046
9/18/2020	Unit 1 Cycle 32 Refueling Outage	N	24.79	24.70	46,826	46,656
10/1/2021	Unit 2 Cycle 32 Refueling Outage	N	26.79	28.40	53,745	56,975
10/14/2022	Unit 1 Cycle 33 Refueling Outage	N	24.71	25.95	62,022	65,134
10/6/2023	Unit 2 Cycle 33 Refueling Outage and Baffle Former	Y	63	147.45	75,776	177,352 <sup>3</sup>

<sup>2</sup> Due to limited access of vendor contracts and vendor labor hour data, this is an estimate. We divided the “Planned Labor Hours” column by the “Planned Outage Duration in Days” column to get the daily planned labor hours. We then took this estimate and multiplied it by the Actual Duration in Outage Days to get the last column, “Estimated Labor Hours.”

<sup>3</sup> The labor hours for the 2023 outage were estimated to be an average of 1,202.8 labor hours daily using the entire 147.45 U2 outage duration. The 1,050 daily average labor hours used in previous calculations (i.e., for

Outage Start Date	Outage Purpose	Cables Replaced? Y/N	Planned Outage Duration in Days	Actual Duration in Outage Days	Planned Labor Hours	Estimated Labor Hours <sup>2</sup>
	Bolt/Clevis Bolt Replacement Projects					
9/20/2024	Unit 1 Cycle 34 Refueling Outage and Baffle Former Bolt/Clevis Bolt Replacement Projects	Y	63	118.95	85,930	162,244

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Witness: Nicholas J. Detmer  
 Preparer: Amanda J. Jepson  
 Title: Manager, Nuclear Regulatory  
 Department: Nuclear Regulatory Policy  
 Telephone: (651) 212-1679  
 Date: June 13, 2025

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work pulled forward) was calculated based on the start of the DC cable replacement outage, so initial Unit 2 Refueling Outage shutdown and defueling activities were not included. During this time period, many of the refueling and valve maintenance contractors were sent home, leading to the lower daily average labor hours calculated for work pulled forward.

- Not-Public Document – Not For Public Disclosure
- Public Document – Not-Public Data Has Been Excised
- Public Document

Xcel Energy Information Request No. 48  
Docket No.: E002/AA-22-179  
Response To: Minnesota Department of Commerce  
Requestor: Richard Dornfeld & Katherine Arnold  
Date Received: June 3, 2025

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Question:

Topic: Prairie Island capacity factor

In Krug direct at 4, Krug states:

PINGP achieved a combined average capacity factor of 95 percent between 2018 and 2022

Provide Prairie Island Nuclear Generating Plant’s combined average annual capacity factor for each year since 2000.

Response:

The combined average annual capacity factor for Prairie Island Units 1 and 2 since 2005 are provided below. Data prior to 2005 is not accessible to the Company.

Year	Average Annual Capacity Factor
2005	88.78%
2006	86.01%
2007	92.51%
2008	84.22%
2009	85.82%
2010	91.82%
2011	89.93%
2012	73.62%
2013	80.64%
2014	87.64%
2015	77.09%
2016	86.03%
2017	91.42%
2018	93.91%
2019	95.55%

<b>Year</b>	<b>Average Annual Capacity Factor</b>
2020	94.70%
2021	94.87%
2022	95.66%
2023	71.39%
2024	66.15%

---

Witness: Allen D. Krug  
Preparer: Amanda J. Jepson  
Title: Manager, Nuclear Regulatory Policy  
Department: Nuclear Policy Planning  
Telephone: (651) 212-1679  
Date: June 13, 2025



414 Nicollet Mall  
Minneapolis, Minnesota 55401

**PUBLIC DOCUMENT  
NOT PUBLIC DATA HAS BEEN EXCISED**

March 1, 2021

**—VIA ELECTRONIC FILING—**

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

RE: ANNUAL TRUE-UP COMPLIANCE REPORT  
2020 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES  
DOCKET NO. E002/AA-19-293

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Annual True-Up and Compliance Report for the fuel forecast and monthly fuel cost charges approved for the 2020 calendar year. This Report also includes compliance items required to be included in the Company's Electric Annual Automatic Adjustment of Charges Reports.

Please note that portions of our Petition and attachments are marked as "Not Public." Certain data is considered to be "not public data" pursuant to Minn. Stat. §13.02, Subd.9, and is "Trade Secret" information pursuant to Minn. Stat. §13.37, subd. 1(b) as this data derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document, and served copies of the summary on the parties on the attached service lists.

If you have any questions regarding this filing please contact Rebecca Eilers at (612) 330-5570 or [rebecca.d.eilers@xcelenergy.com](mailto:rebecca.d.eilers@xcelenergy.com) or me at 612-330-7681 or [lisa.r.peterson@xcelenergy.com](mailto:lisa.r.peterson@xcelenergy.com).

**PUBLIC DOCUMENT**  
**NOT PUBLIC DATA HAS BEEN EXCISED**

*vi. Company-Owned Nuclear Generation*

The Company-owned nuclear forecast includes key modeling parameters, such as monthly operating capacity, based on the capability of each individual unit. Planned maintenance for each unit, as well as forced outage rates based on historical data and expected conditions going forward, are included in the forecasted nuclear rates. Forecasted nuclear fuel price is based on the Company’s existing nuclear fuel contracts at the time the forecast was filed.

**Figure 6: Company-Owned Nuclear Forecast to Actuals**

	2020 (\$000)			2020 GWh			2020 \$/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
<b>Nuclear</b>	119,986	116,954	3,032	14,677	14,071	606	\$8.17	\$8.31	-\$0.14

Actual Company-owned nuclear generation experienced better-than-forecast performance in 2020 due to a lower than forecast outage rate. Recent investments made in our nuclear plants have paid off over the past several years, and that success continued into 2020. As of March 1, 2021 Monticello continues to operate at 657 continuous days online, Prairie Island Unit 1 at 139 days following a fall 2020 refueling outage, and unit 2 at 490 days. Over the past several years, plants have experienced improved performance during plant refueling outages, which were completed on time and on budget. In short, our nuclear fleet has never performed better.

Part C, Attachments 4 and 5 provide details on actual outages in 2020, including a comparison of forecast to actual outage costs by unit.

*vii. Purchased Natural Gas Generation*

The purchased natural gas forecast includes key modeling parameters, such as operating capacity and heat rate, based on capabilities of the individual plants or according to terms specified in the individual Power Purchase Agreements (PPAs). Planned maintenance for each unit based on the overhaul schedule provided by the PPA counterparty, as well as forced outage rates based on historical data and expected plant conditions going forward, are included in the forecasted purchased natural gas rates.

Direct Testimony and Schedule  
Pamela Prochaska

Before the Minnesota Public Utilities Commission  
State of Minnesota

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  
Prairie Island Nuclear Generating Plant Independent Spent Fuel Storage Installation

Docket No. E002/CN-24-68  
Exhibit\_\_\_\_(PP-1)

**Nuclear Policy and Operations**

February 10, 2025

1 Q. CURRENTLY, WHAT IS THE PRAIRIE ISLAND PLANT'S CAPACITY FACTOR?

2 A. The capacity factor, or operating time, for the Prairie Island Plant has been at  
3 an average of 90 percent for the past five years from 2019 through 2023. This  
4 reflects the strong performance at the Plant based on the capital investments  
5 and operational improvements the Company made over the past decade.

6

7 Q. WHAT DOES THE COMPANY ANTICIPATE WITH RESPECT TO O&M AND  
8 PRODUCTION COSTS FOR THE NEXT SEVERAL YEARS?

9 A. The Company cannot completely predict the Plant's operating costs into the  
10 future, but in our current rate case, we do anticipate an increase in O&M over  
11 the next few years. We anticipate that the predicted level of expenditure will  
12 ensure that the Plant will continue to run safely and efficiently, so that the  
13 Company's customers can expect to enjoy low-cost, clean, and reliable power  
14 for years to come should the Plant's life be extended.

15

16 Q. ARE THERE OTHER BENEFITS OF THE PRAIRIE ISLAND PLANT AND ITS ROLE IN  
17 THE COMPANY'S OVERALL PORTFOLIO THAT SHOULD BE CONSIDERED IN THIS  
18 PROCEEDING?

19 A. Yes. Traditionally, nuclear plants have been considered must-run baseload  
20 power and have been run continually at maximum power except during outages.  
21 However, the Company has recently prioritized developing a flexible power  
22 operations strategy that allows its nuclear facilities, including the Prairie Island  
23 Plant, to reduce power output during periods when other resources are  
24 providing large amounts of low-cost energy relative to customer demand such  
25 that it would be economically beneficial to run baseload resources at lower  
26 levels. The Company has developed operational strategies for its nuclear plants  
27 that allow them to maneuver from full output to a level of reduced output.

Direct Testimony and Schedules  
Peter A. Gardner

Before the Minnesota Public Utilities Commission  
State of Minnesota

In the Matter of the Application of Northern States Power Company  
for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-21-630  
Exhibit\_\_\_\_(PAG-1)

**Nuclear Operations**

October 25, 2021

1 materials costs included in O&M are generally those consumed in the operating  
2 process or small in amount and are in addition to materials capitalized in  
3 construction projects.

4  
5 A key element of materials for nuclear utilities is the regulatory scrutiny and  
6 rules for equipment components and parts in use at our plants. Replacement  
7 and repair parts must meet regulatory qualification requirements for safety  
8 tolerances. Given the fact that most nuclear plants are 40+ years old, the  
9 original equipment manufacturers (OEM) may no longer be in business or  
10 produce the same components. The availability of replacement OEM  
11 components from vendors, or the time needed to qualify new components as  
12 acceptable, can create plant licensing basis and shutdown risks due to non-  
13 conformance with requirements.

14  
15 Q. WHAT ARE THE MAJOR TRENDS IN MATERIALS COSTS OVER THE LAST THREE  
16 YEARS AND THROUGH THE TEST YEAR?

17 A. As Table 7 above shows, materials costs decreased from 2018 to 2020 from  
18 \$15.3 million to \$11.4 million. We are forecasting even lower costs of about  
19 \$10.3 million in 2021, with increases in 2022 to \$10.6 million, which remains  
20 lower than 2020 levels.

21  
22 Q. WHAT ARE THE DRIVERS BEHIND THESE TRENDS?

23 A. With consistent plant operation of three nuclear units, many of the chemicals,  
24 supplies, and inventoried parts and materials needed to operate our three  
25 nuclear units remain constant over time and represent a base level of cost that  
26 does not fluctuate notably.

1 The \$1 million decrease from 2020 to 2021 is largely due to decreased  
2 maintenance and project work planned in 2021. The continuing pandemic  
3 strategy is to defer work as much as possible without compromising safe  
4 operations. We are expecting to return to pre-COVID maintenance volumes  
5 in 2022, with a focus on work that had been deferred.

6  
7 5. *Employee Expenses*

8 Q. PLEASE DISCUSS WHAT EMPLOYEE EXPENSES ARE INCLUDED IN THE NUCLEAR  
9 OPERATION BUSINESS AREA'S 2022 TEST YEAR O&M BUDGET.

10 A. Employee expenses are comprised mainly of the costs for Nuclear employees  
11 to travel both within and outside the Company's service territory for business  
12 reasons. The most common need for travel is for: staff travel (by car) between  
13 plant sites and fleet headquarters to provide support and oversight; meetings  
14 with regulatory and oversight agencies such as NRC and INPO; meetings and  
15 initiatives with industry groups such as NEI, EEI, and USA; performing  
16 industry benchmarking with and quality reviews (including INPO) for other  
17 nuclear utilities; and vendor oversight for quality assurance (which can involve  
18 international travel). We critically review employee expenses and are working  
19 hard to optimize the benefit of such travel in consideration of the associated  
20 costs.

21  
22 Q. WHAT ARE THE MAJOR TRENDS IN NUCLEAR EMPLOYEE EXPENSES OVER THE  
23 LAST THREE YEARS AND THROUGH THE TEST YEAR?

24 A. As Table 7 above shows, employee expenses increased from 2018-2019 from  
25 \$3.0 million in 2018 to \$3.6 million in 2019. In 2020, we experienced a  
26 significant decrease to \$1.8 million, with employee expenses predicted to remain  
27 relatively flat into 2022.