**BEFORE THE MINNESOTA COURT OF ADMINISTRATIVE HEARINGS**
**600 North Robert Street**
**Saint Paul, Minnesota 55101**

**FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION**
**121 Seventh Place East, Suite 350**
**Saint Paul, Minnesota 55101-2147**

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

**OAH Docket No. 21-2500-40336**
**MPUC Docket No. E-002/AA-22-179**

# PROPOSED FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY

**January 8, 2026**

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|---|---|
| In the Matter of Xcel Energy's Petition for Approval of its 2023 Annual Fuel Forecast and Monthly Fuel Cost Charges | OAH Docket No. 21-2500-40336<br>MPUC Docket No. E-002/AA-22-179 |

The above-entitled matter came on for an evidentiary hearing before the Honorable Kimberly Middendorf, Administrative Law Judge, on September 30, 2025, at the offices of the Minnesota Public Utilities Commission in St. Paul, Minnesota.

Eric Swanson and Elizabeth Schmiesing, Winthrop & Weinstine, P.A. and Ian Dobson and Lauren Steinhaeuser, Northern States Power Company – Minnesota, d/b/a Xcel Energy, appeared for and on behalf of Northern States Power Company d/b/a Xcel Energy (Xcel Energy or Company).

Katherine Arnold and Richard Dornfeld, Assistant Attorneys General, appeared for and on behalf of the Minnesota Department of Commerce, Division of Energy Resources (Department or DOC).

Peter Scholtz and Joey Cherney, Assistant Attorneys General, appeared for and on behalf of Minnesota Office of the Attorney General – Residential Utilities Division (OAG).

Brian Edstrom, Senior Regulatory Advocate, appeared for and on behalf of Citizens Utility Board of Minnesota (CUB).

Amber Lee and Eden Fauré, Stole Rives, LLP, appeared for and on behalf of the Xcel Large Industrials (XLI).

Ashley Marcus and Hirsi Mohamed appeared for and on behalf of the Minnesota Public Utilities Commission (Commission).

## STATEMENT OF THE ISSUES

1. Whether an outage at the Prairie Island Nuclear Generating Plant (Prairie Island or PINGP) in late 2023 and early 2024 caused Xcel Energy customers

to pay more for electricity than they would have had the outage not occurred, including an assessment of:

a. What is the best estimate of any additional costs for power the Company incurred because PINGP power was not available during the outage?

b. What is the appropriate value of benefits or offsets that mitigate any additional power costs in whole or in part?

## SUMMARY OF FACTS AND RECOMMENDATION

On October 19, 2023, a work team at the PINGP inadvertently struck a bundle of control cables during a cable-replacement project, severing the cables and leading PINGP Unit 1 to shut down (the Event). During the time required for Xcel Energy to replace the severed cables and return it to service, the Company purchased replacement power. The cost of that replacement power was included in Xcel Energy's Annual Automatic Adjustment (AAA) Reports and recovered from customers.

The Commission determined that the Company acted imprudently by inadvertently severing the cables, but deferred making a final determination on the recoverability of these costs and referred this matter to the Office of Administrative Hearings (now Court of Administrative Hearings (COA)) for a contested case hearing to determine the appropriate ratepayer refund amount resulting from the Event, if any. To the extent this "replacement power" cost more than customers would have paid absent the Event and outage, and to the extent those incremental costs are not fully offset by other avoided costs or consideration of other customer benefits realized because of the outage, a refund of any remaining incremental impact on customers may be appropriate.[1]

The central debates in this proceeding, therefore, concerned how to most reliably and accurately estimate the replacement power costs and how to value any demonstrated avoided costs or benefits. The course of the record development in this contested case hearing refined these two central considerations for determining the appropriate ratepayer refund amount resulting from the Event, which are best articulated by the following questions: (1) what is the best estimate of any additional costs the Company incurred for power because PINGP power was not available during the outage, and (2) are there any offsetting cost savings or customer benefits not captured in the replacement power cost

[1] ORDER APPROVING 2023 FUEL-CLAUSE TRUE-UP REPORT, REQUIRING ADDITIONAL FILINGS, FINDING IMPRUDENCE, AND NOTICE OF AND ORDER FOR HEARING at 4, 8 (Nov. 15, 2024) (eDocket No. 202411-211999-01) (hereinafter NOTICE OF AND ORDER FOR HEARING).

analysis that must be considered to fully assess the ultimate financial impact of the outage on customers?

The answer to the first of these questions – what is the best estimate of additional costs for power, if any, incurred by Xcel Energy due to PINGP being offline – involves the evaluation of a number of inputs and requires creating an alternate history, one in which the outage never happened, to determine what Xcel Energy's costs would have been had PINGP been fully operational. Those costs are then compared to the costs actually incurred in the outage. This analysis requires consideration of several key pieces of information, including: (1) PINGP and its role in both Xcel Energy's generation portfolio and in the broader Midcontinent Independent System Operator (MISO) energy marketplace; (2) aspects of how that broader MISO energy marketplace operates; (3) the work performed by Xcel Energy during the outage and whether that work impacted the duration of the outage; and (4) the available tools to reliably estimate the impact of the outage on Xcel Energy's power costs.

Answering the second question – the value of additional offsetting cost savings or benefits to customers from the work done by the Company during the outage – again requires consideration of numerous factors. It starts with an understanding of Xcel Energy's work during the outage to determine whether that work shortened or avoided future outages, such that the cost savings of those shortened or avoided future outages should be considered in determining an appropriate refund amount. That determination, in turn, requires consideration of the framework within which PINGP was operating, including plant operation and maintenance protocols, federal guidance concerning plant operations and maintenance, and the federal relicensing process that applied to PINGP. Once any such offsets or benefits are identified, valuing those offsets or benefits then requires a similar analysis to that used for estimating additional power costs.

The evidence in this case establishes that Xcel Energy provided the most appropriate calculation of replacement power costs, as well as offsetting cost savings and other benefits. In particular, the power cost modeling performed by Xcel Energy provides the most reliable estimate of the additional power costs incurred during the outage because it considers the relevant variables and provides the most accurate estimate of those costs. Additionally, the record demonstrates that customers benefited from both PINGP's prior performance and from the Company's work at PINGP during the outage, which avoided significant future outage costs. Taken together, this full analysis of the impact of the outage on customers demonstrates that the overall net impact of the outage on customers is between $7.4 million and $12.8 million, plus interest, depending on whether the Commission considers PINGP's prior operating history and whether Xcel Energy is held to a standard of perfect performance.

## FINDINGS OF FACT

## I. PROCEDURAL BACKGROUND

1. On March 1, 2024, the Company filed its Annual Fuel Clause True-Up and Compliance Report for fuel forecast and fuel-cost charges approved for the 2023 calendar year (2023 AAA Report). In the 2023 AAA Report, Xcel Energy reported 2023 actual fuel cost collections of approximately $1,091.8 million from its Minnesota customers. Further, the Company noted that it refunded $30.5 million to customers from July through September 2023 through a mid-year rate decrease. Therefore, net total Minnesota fuel collections were $1,061.3 million. The Company also reported its total actual fuel expense for 2023 of $935.3 million, meaning it over-collected fuel costs by $126.0 million for 2023, and the Company proposed to refund this amount to customers.[2]

2. On April 15, 2024, the Department of Commerce, Division of Energy Resources (Department) filed comments.[3]

3. On May 1, 2024, the Company filed reply comments.[4]

4. On May 15, 2024, the Department filed supplemental comments[5] and the Office of the Attorney General – Residential Utilities Division (OAG) filed comments.[6]

5. By June 18, 2024, five members of the public had filed comments.[7]

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[2] Exhibit (Ex.) Xcel-1 at 7 (Krug Direct).

[3] Comments of the Department (April 15, 2024) (eDocket Nos. 20244-205419-01 and 20244-205419-02).

[4] Xcel Energy Reply Comments (May 15, 2024) (eDocket Nos. 20245-206282-01, 20245-206282-02 and 20245-206282-03).

[5] Supplemental Comments of the Department (May 15, 2024) (eDocket Nos. 20245-206783-01 and 20245-206783-02) (attachments omitted inadvertently submitted May 21, 2024 – eDocket Nos. 20245-206953-02, 20245-206953-03, 20245-206953-04, 20245-206953-05 and 20245-206953-06).

[6] Comments of the OAG (May 15, 2024) (eDocket Nos. 20245-206795-01 and 20245-206795-02).

[7] Public Comment of Pamela Janisch (June 10, 2024) (eDocket No. 20246-207538-01); Public Comment of Judy Corson (June 10, 2024) (eDocket No. 20246-207533-01); Public Comment of David Bergstrom (June 10, 2024) (eDocket No. 20246-207529-01); Public Comment of Zachary Siegel (June 18, 2024) (eDocket No. 20246-207775-01); Public Comment of Quentin Ritchie (June 18, 2024) (eDocket No. 20246-207775-01).

6. On July 30, 2024, the Citizens Utilities Board of Minnesota (CUB) filed reply comments[8] and the Company filed supplemental reply comments.[9]

7. On August 23, 2024, the Department filed comments responding to the Company's July 30, 2024 filing.[10]

8. On September 19, 2024, the Commission met to consider this matter and approved the non-nuclear aspects of the 2023 AAA Report and the Company's proposed $126 million refund to customer.[11]

9. As to the potential impact of the PINGP outage, the Commission found that further record development was necessary to determine the impact of the outage on the power costs paid by customers and whether potential benefits or offsets should be considered before requiring any refund of costs incurred during the outage.[12]

10. On November 15, 2024, the Commission referred this matter to the Court of Administrative Hearings for this contested case proceeding.[13]

11. The initial parties to the contested case proceeding were the Company, the Department, and the OAG.[14]

12. On November 27, 2024, the Administrative Law Judge Kimberly Middendorf issued the First Prehearing Order and established the following schedule of proceedings:[15]

| DATE | EVENT | DESCRIPTION |
|---|---|---|
| April 1, 2025 | Intervention Deadline | All petitions for intervention shall be served and filed by this date. |

[8] Reply Comments of CUB (July 30, 2024) (eDocket No. 20247-209116-01).
[9] Xcel Energy Supplemental Reply Comments (July 30, 2024) (eDocket Nos. 20247-209117-01, 20247-209117-02, 20247-209117-03 and 20247-209117-04).
[10] Department Reply Comments (Aug. 23, 2024) (eDocket No. 20248-209745-01).
[11] NOTICE OF AND ORDER FOR HEARING at 2 (Nov. 15, 2024) (eDocket No. 202411-211999-01).
[12] NOTICE OF AND ORDER FOR HEARING at 2 (Nov. 15, 2024) (eDocket No. 202411-211999-01).
[13] NOTICE OF AND ORDER FOR HEARING at 8 (Nov. 15, 2024) (eDocket No. 202411-211999-01).
[14] NOTICE OF AND ORDER FOR HEARING at 2 (Nov. 15, 2024) (eDocket No. 202411-211999-01).
[15] FIRST PREHEARING ORDER at 2-5 (Nov. 27, 2024) (eDocket No. 202411-212514-01).

| DATE | EVENT | DESCRIPTION |
|---|---|---|
| May 1, 2025 | Xcel Direct Testimony Due | Xcel's direct testimony shall be served and filed by this date. Xcel shall simultaneously serve and file its direct testimony. |
| July 2, 2025 | Other Party Direct Testimony | All other parties' direct testimony shall be served and filed by this date. The parties shall simultaneously serve and file their direct testimony. |
| August 13, 2025 | Rebuttal Testimony Due | All rebuttal testimony shall be served and filed by this date. The parties shall simultaneously serve and file their rebuttal testimony. |
| September 17, 2025 | Surrebuttal Testimony Due | All surrebuttal testimony shall be served and filed by this date. The parties shall simultaneously serve and file their surrebuttal testimony. |
| September 22, 2025 | Foundations Objections Due | Foundation objections must be served and filed by September 22, 2025. |

| DATE | EVENT | DESCRIPTION |
|---|---|---|
| September 25, 2025 | Service and Filing of Proposed Witness Lists, Proposed Exhibit Lists, and Proposed Exhibits | By 4:30 p.m., the parties shall serve and file, in the eDockets system, their proposed witness lists, proposed exhibit lists, and proposed exhibits. Proposed exhibit lists shall be clearly titled as: "[Party Name's] Proposed Exhibit List."<br><br>The parties shall also circulate among themselves via email, their proposed exhibit lists. The parties shall include the Administrative Law Judge and the court reporter in the email circulation of the proposed exhibit list. The proposed exhibit list shall be in the template form provided by the court reporter so that it can be compiled by Applicant into a Master Exhibit List.<br><br>At the conclusion of the hearing, Xcel shall prepare the Master Exhibit List using the template provided by the court reporter. The Master Exhibit List shall be given to the court reporter and filed in eDockets. The Master Exhibit list shall contain live links to the documents in eDockets and include the eDocket document numbers. |
| September 26, 2025 | **Second Prehearing Conference**<br><br>**10:00 a.m.** | The parties shall appear for a second prehearing conference to discuss hearing logistics. The settlement conference shall be conducted via telephone. Dial **1(651)395-7448**, and when prompted enter code **925 808 303#**. |
| September 30 and October 1, 2025 | **Evidentiary Hearing**<br><br>**9:30 a.m.**<br><br>**Public Utilities Commission**<br>**171 7th Place E. #350**<br>**St. Paul, MN** | An evidentiary hearing will be held at the office of the Public Utilities Commission (large or small hearing room) in St. Paul, commencing at 9:30 a.m. each day. |

| DATE | EVENT | DESCRIPTION |
|---|---|---|
| November 25, 2025 | Initial Briefs Due | By 4:30 p.m., the parties shall serve and file their Initial Briefs.<br><br>In addition to serving and filing their briefs in the eDockets system, the parties shall provide the Administrative Law Judge with: (1) a paper copy of their Initial Briefs via personal delivery or U.S. Mail; and (2) a Microsoft Word version of their Initial Briefs via email at: kimberly.middendorf@state.mn.us |
| January 8, 2026 | Responsive Briefs and Proposed Findings Due | By 4:30 p.m., the parties shall serve and file their Response Briefs and Proposed Findings.<br><br>In addition to serving and filing their documents in the eDockets system, the parties shall provide the Administrative Law Judge with: (1) a paper copy of their documents via personal delivery or U.S. Mail; and (2) a Microsoft Word version of their Responsive Briefs and Proposed Findings via email at: kimberly.middendorf@state.mn.us. |
| March 16, 2026 | Administrative Law Judge's Report Due | The Judge shall file her Findings of Fact, Conclusions of Law, and Recommendation. |

13. In the First Prehearing Order, Judge Middendorf established the parties in the contested case hearing to be the Company, the Department, the OAG, CUB and XLI.[16]

14. On December 5, 2024, the Department petitioned the Minnesota Public Utilities Commission to make a limited clarification of its November 15 Order.[17]

[16] FIRST PREHEARING ORDER at 2 (Nov. 27, 2024).
[17] Department Request for Clarification (Dec. 5, 2024) (eDocket No. 202412-212749-01).

15. On December 5, 2024, the Company petitioned the Commission to reconsider its November 15, 2024 Order.[18]

16. On December 16, 2024, CUB filed its Answer to the Company's Petition for Reconsideration.[19]

17. On December 16, 2024, the OAG filed its Answer to the Company's Petition for Reconsideration and the Department's Request for Clarification.[20]

18. On December 16, 2024, the Department filed its Answer to the Company's Petition for Reconsideration.[21]

19. And, on December 16, 2024, the Company filed its Answer to Petition for Clarification.[22]

20. Subsequently, the Commission clarified the issues to be addressed in its January 31, 2025 Order Denying Reconsideration and Granting Request for Clarification (Order).[23]

21. On May 1, 2025, the Company filed its Direct Testimony in this proceeding.[24]

22. On June 27, 2025, the Company filed errata to the Direct Testimony and Schedules of Nicholas J. Detmer.[25]

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[18] Xcel Energy Petition for Rehearing and Reconsideration (Dec. 5, 2024) (eDocket No. 202412-212755-01) (Petition for Reconsideration).

[19] CUB Answer to the Company's Petition for Reconsideration (Dec. 16, 2024) (eDocket No. 202412-213043-01).

[20] OAG Answer to Xcel Energy's Petition for Reconsideration and the Department of Commerce's Request for Clarification (Dec. 16, 2024) (eDocket No. 202412-213045-02).

[21] Department Answer to Xcel Energy's Petition for Reconsideration (Dec. 16, 2024) (eDocket No. 202412-213069-01).

[22] Xcel Energy's Answer to Petition for Clarification (Dec. 16, 2024) (eDocket No. 202412-213064-01).

[23] ORDER DENYING RECONSIDERATION AND GRANTING REQUEST FOR CLARIFICATION (Jan. 31, 2025) (eDocket No. 20251-214793-01) (hereinafter CLARIFYING ORDER).

[24] *See* Ex. Xcel-1-2, 4-5, 10 and 13.

[25] *See* Ex. Xcel-6-7.

23. On July 2, 2025, Joint Intervenors' (consisting of CUB, DOC, OAG and XLI) filed Notice of Motion and Motion for Partial Summary Disposition, Memorandum Supporting Partial Summary Disposition and Declaration of Richard Dornfeld.[26]

24. On July 2, 2025, the Department, OAG, and XLI filed Direct Testimony in this proceeding.[27]

25. On July 17, 2025, the Company filed its Memorandum in Opposition to Joint Intervenors' Motion for Partial Summary Judgment.[28]

26. On August 13, 2025, the CAH issued its Order Denying Motion for Partial Summary Judgment.[29]

27. On August 13, 2025, the Company filed its Rebuttal Testimony.[30]

28. On September 17, 2025, the Department, OAG, and XLI filed their Surrebuttal Testimonies.[31]

29. On September 22, 2025, the Company filed its Notice of Motion and Motion to Strike[32] and Memorandum of Law in Support of Motion to Strike Certain Surrebuttal Testimony of Brian C. Andrews.[33]

30. On September 23, 2025, the Company filed its Notice of Motion and Motion to Provide Responsive Testimony[34] and Memorandum of Law in Support of Motion to

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[26] Joint Intervenors' Notice of Motion and Motion for Partial Summary Disposition, Memorandum Supporting Partial Summary Disposition and Declaration of Richard Dornfeld (July 2, 2025) (eDocket Nos. 20257-220598-02, 20257-220598-03 and 20257-220598-04).

[27] *See* Ex. DOC-1; Exs. OAG-1 – OAG-3; Exs. XLI-1 – XLI-2.

[28] Xcel Energy's Memorandum in Opposition to Joint Intervenors' Motion for Partial Summary Judgment (July 17, 2025) (eDocket No. 20257-221097-01).

[29] ORDER DENYING PARTIAL SUMMARY JUDGMENT (Aug. 13, 2025) (eDocket No. 20258-222028-01).

[30] *See* Ex. Xcel-3, 8-9, 11-12, 14.

[31] *See* Exs. DOC-2 - DOC-3; Ex. OAG-4; Exs. XLI-3 – XLI-4.

[32] Xcel Energy's Notice of Motion and Motion to Strike (Sept. 22, 2025) (eDocket No. 20259-223213-01).

[33] Xcel Energy's Memorandum of Law in Support of Motion to Strike Certain Surrebuttal Testimony of Brian C. Andrews (Sept. 22, 2025) (eDocket No. 20259-223213-02).

[34] Xcel Energy's Notice of Motion and Motion to Provide Responsive Testimony (Sept. 23, 2025) (eDocket No. 20259-223236-01).

Provide Responsive Testimony to the Surrebuttal Testimony of Department of Commerce Witness Dr. Steve Rakow.[35]

31. On September 24, 2025, the Department filed Correspondence Responding to Xcel's Motion to Provide Responsive Testimony.[36]

32. On September 25, 2025, XLI filed Errata to Brian Andrews Direct Testimony.[37]

33. On September 25, 2025, XLI filed correspondence in opposition to Xcel Energy's Motion to Strike Certain Surrebuttal Testimony of Brian C. Andrews.[38]

34. On September 26, 2025, a Prehearing Conference was held.[39]

35. On September 30, 2025, the Evidentiary Hearing was held.[40]

36. On November 25, 2025, the Company, the Department, OAG, CUB, and XLI filed Initial Briefs in this proceeding.[41]

## II. STATEMENT OF ISSUES

37. In the Order, the Commission clarified the issues to be addressed in this proceeding in three ways. First, the Order states:

> The Commission grants the Department's request for clarification and adopts the amendments to the November 15, 2024 order shown on pages 5–6 of the Department's December 5, 2024 filing, clarifying that the contested case

[35] Xcel Energy's Memorandum of Law in Support of Motion to Provide Responsive Testimony to the Surrebuttal Testimony of Department of Commerce Witness Dr. Steve Rakow (Sept. 23, 2025) (eDocket No. 20259-223236-02).
[36] Department Response to Xcel's Motion to Provide Responsive Testimony (Sept. 24, 2025) (eDocket No. 20259-223279-01).
[37] *See* XLI-5.
[38] XLI correspondence in opposition to Xcel Energy's Motion to Strike Certain Surrebuttal Testimony of Brian C. Andrews (Sept. 25, 2025) (eDocket No. 20259-223319-01).
[39] *See* Prehearing Conference Transcript (Sept. 26, 2025) (eDocket No. 202511-224972-01).
[40] *See* Evidentiary Hearing Transcript (Tr.) (Sept. 30, 2025) (eDocket No. 202511-224972-02).
[41] Xcel Energy Initial Brief (Nov. 25, 2025) (eDocket No. 202511-225292-01); Department Initial Brief (Nov. 25, 2025) (eDocket No. 202511-225265-01); OAG Initial Brief (Nov. 25, 2025) (eDocket No. 202511-225275-02); CUB Initial Brief (Nov. 25, 2025) (eDocket No. 202511-225294-02); XLI Initial Brief (Nov. 25, 2025) (eDocket Nos. 202511-225296-02 – 202511-225296-03).

issues are limited to the refund owed to ratepayers for costs that flow through the fuel-clause adjustment report.[42]

38. The specific amendments recommended by the Department and adopted by the Commission modified the Commission's earlier order in this matter as follows:

> Over the course of this case, the Commission expects the parties will thoroughly develop a full record~~,~~ addressing~~, at a minimum,~~ the appropriate refund amount due to ratepayers for replacement power costs in 2023 and 2024 stemming from the lack of prudence regarding the October 2023 outage at PINGP.
>
> The Commission refers this matter to the Minnesota Office of Administrative Hearings for a contested case to determine the appropriate refund amount due to customers for replacement power costs in 2023 and 2024 due to Xcel's lack of prudence regarding the October 2023 outage at Prairie Island.[43]

39. Second, the Commission clarified that this proceeding would not address other issues potentially related to the outage such as the impact of any derating of PINGP on capacity costs, but that any such issues would be addressed in the Company's ongoing electric rate case.[44]

40. Third, the Commission stated:

> The Commission further clarifies that the contested case shall also consider any benefits and offsets in determining the appropriate refund and consider whether imprudence by Xcel Energy resulted in customers paying more for power than they otherwise would have paid such that a refund of power costs is appropriate.[45]

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[42] ORDER DENYING PETITION FOR RECONSIDERATION AND GRANTING REQUEST FOR CLARIFICATION at 4. Ordering ¶ 2 (Jan. 31, 2025) (eDocket No. 20251-214793-01).
[43] ORDER DENYING PETITION FOR RECONSIDERATION AND GRANTING REQUEST FOR CLARIFICATION at (Jan. 31, 2025) (eDocket No. 20251-214793-01) (markings in original).
[44] ORDER DENYING PETITION FOR RECONSIDERATION AND GRANTING REQUEST FOR CLARIFICATION at 4. Ordering ¶ 2 (Jan. 31, 2025) (eDocket No. 20251-214793-01).
[45] ORDER DENYING PETITION FOR RECONSIDERATION AND GRANTING REQUEST FOR CLARIFICATION at 4. Ordering ¶ 3 (Jan. 31, 2025) (eDocket No. 20251-214793-01).

41. Thus, as discussed above and as stated by Xcel Energy witness Allen Krug, this case requires answering two questions:

a. What is the best estimate of any additional power costs Xcel Energy may have incurred during the outages of Units 1 and 2 due to the Event?

b. What is the appropriate value of benefits or offsets that mitigate any additional power costs in whole or in part?[46]

## III. OVERVIEW OF PRAIRIE ISLAND, THE EVENT, AND THE COMPANY'S RESPONSE

### A. Prairie Island And Its Role In The Company's Generation Portfolio And In MISO

42. The Prairie Island Plant is a two-unit, nuclear-powered, electric generating station located in Red Wing, Minnesota.[47] Since it began operating in 1973 and 1974, PINGP has played a critical role in Xcel Energy's fleet of resources, providing low-cost, carbon-free baseload energy service, and is among the most reliable resources in the Company's fleet.[48]

43. In 2022, PINGP's two reactors operated at a combined 96 percent capacity factor and both units have consistently achieved an average capacity factor of 90 percent or more, achieving a combined average capacity factor of 95 percent between 2018 and 2022 – performance levels well above the industry average.[49]

44. Xcel Energy customers have benefited from this consistent and reliable operation of PINGP over the last several years, including during the 2019 polar vortex, the 2021 Winter Storm Uri, and others, where reliable energy supply was critical.[50] In total, over the five year period from 2018 through 2022, PINGP generated approximately 2,577 GWh above the Company's forecasted amount, benefiting Xcel Energy customers by more than $50 million. Customers exclusively benefit from this strong performance because they do not pay anything incremental—and the Company does not receive incremental compensation—for it.[51]

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[46] Ex. Xcel-1 at 9 (Krug Direct).
[47] Ex. Xcel-1 at 4 (Krug Direct).
[48] Ex. Xcel-1 at 4 (Krug Direct).
[49] Ex. Xcel-1 at 4 (Krug Direct); Ex. Xcel-4 at 20-21 and Schedule 3 (Detmer Direct); Ex. Xcel-10, Schedule 2 at 6 (Bible Direct).
[50] Ex. Xcel-1 at 4 (Krug Direct); Ex. Xcel-4 at 21 (Detmer Direct).
[51] Ex. Xcel-1 at 4-5 (Krug Direct); Ex. Xcel-4 at 21-22 (Detmer Direct).

45. As a key component of Xcel Energy's generation portfolio, PINGP also plays a significant role within the Minnesota region of the larger MISO North energy market. In fact, while Xcel Energy itself has a large electric generation portfolio, PINGP alone represents approximately 13 percent of the energy generated within the Minnesota region of the MISO North market.[52]

46. The Minnesota region of the MISO North market is what MISO refers to as a "Narrow Constrained Area" (NCA), meaning constraints in the transmission system can create bottlenecks and limit the ability to move power. The Company is often price isolated from the broader energy market and must address disruptions within its generation portfolio with its own resources, rather than purchasing additional power on the MISO market. This occurred during the outage following the Event, when the Company saw the generation at other Xcel Energy facilities increase from their previously forecasted generation due to the loss of PINGP.[53]

### B. The MISO Market

47. MISO is an independent transmission system operator that handles, among other things, electricity market facilitation for certain geographical electric markets. The MISO footprint covers multiple states and the Province of Manitoba, stretching as far south as Louisiana, and it includes all of Northern States Power Company – Minnesota's service territory and its transmission and generation assets.[54]

48. Regarding its facilitation of the electricity market, Xcel Energy witness Mr. Nicholas Detmer explained that, at a high level:

> The MISO electricity market is a "two-pass" market that seeks to minimize costs across the footprint MISO manages. The first pass is the Day-Ahead market, and the second pass is the Real-Time market. Starting with the Day-Ahead market, Market Participants offer to sell all the available generation under their control to MISO. Simultaneously, Market Participants with load obligations bid to buy load from the market. A generation resource "clears" the market when it submits an offer to sell into the market, and that resource is needed to fulfill the load obligations of the market. The cheapest generation resource offered into the market will clear the market first, then the next cheapest, and so on. MISO determines from these bids and offers where supply and demand intersect, and from there sets a wholesale price based on the last generation resource required to meet the demand, referred to as the Locational Marginal Price (LMP). All resources that cleared the

[52] Ex. Xcel-4 at 13 (Detmer Direct); Tr. at 56 (Detmer).
[53] Tr. at 54-56 (Detmer)
[54] Ex. Xcel-4 at 3 (Detmer Direct); Ex. Xcel-8 at 11 (Detmer Rebuttal).

> market sell energy at their LMP. The LMP is specific to generators and loads on the transmission grid, called Commercial Pricing nodes.[55]

49. Mr. Detmer further explained that the final derivation of LMPs is far more complex than this high-level view and considers multiple variables such as minimum run times of certain generators, start-up times and costs, hourly costs, transmission constraints, planned outages, and required reserves to respond to disruptions in the system.[56]

50. LMPs vary across the MISO footprint, depending on the location of the Commercial Pricing node. As Mr. Detmer discussed, two elements lead to this different pricing: distance and transmission capacity.[57]

51. Regarding distance, the further a generator is from loads, the higher the transmission energy losses associated with that generator will be, meaning more energy is needed to meet the load at that Commercial Pricing node.[58]

52. Regarding transmission capacity, there are areas of constraints of the transmission system, and at times the system can approach its maximum capacity. When this occurs, the market responds by disfavoring generation located in areas of constrained capacity.[59]

53. For a market participant such as Xcel Energy that both offers load into the market and purchases back from that same market, customers are not always paying LMP prices for their energy. When Xcel Energy generation facilities produce energy at generation costs below the LMP, the Company's sales from the facility into the market (at LMP pricing tied to the location of the Company's generators) and purchases back from the market (also at LMP pricing, but tied to the location of the Company's load) net out, and customers pay only the net generation costs.[60]

54. To illustrate this in the MISO Day-Ahead market, Mr. Detmer provided the following example:

> Assume Xcel Energy has a 100 Megawatt (MW) load that it must serve by buying energy from MISO. At the same time, Xcel Energy has two power plants selling energy to MISO. Put another way, the same Market Participant, in this case, Xcel Energy, is acting as both buyer and seller. Again, assume that one power plant generates 30 MW and costs $50/MWh and a second

[55] Ex. Xcel-4 at 3 (Detmer).
[56] Ex. Xcel-4 at 4 (Detmer Direct).
[57] Ex. Xcel-4 at 10 (Detmer Direct).
[58] Ex. Xcel-4 at 10 (Detmer Direct).
[59] Ex. Xcel-4 at 10 (Detmer Direct).
[60] Ex. Xcel-4 at 4-6, 10 (Detmer Direct).

plant generates 90 MW and costs $25/MWh. Even though the 90 MW plant clears the market at $25/MWh, some generation from the second plant that offers to sell its generation at $50/MWh is required to fulfill the load demand of 100 MW. In this simple example, the Locational Marginal Price will clear at $50 (the lowest cost to serve all of the load). Load – the power purchaser – pays 100 MW x $50/MWh = $5,000. The generators receive revenue according to the Locational Marginal Price (LMP), so the 90 MW plant revenues = 90 MW x $50/MWh = $4,500 and the 30 MW plant revenues = 10 MW x $50/MWh = $500. The Xcel Energy Market Participant, acting as both load and generation, received $5,000 for all the generation sold while paying $5,000 for the energy purchased resulting in a net market interaction of $0. Through the Company's fuel clause adjustment, the Company will pass 90 MW x $25/MWh + 10 MW x $50/MWh = $2,750 through to its customers [not the $5000 paid for the energy purchased]. In other words, the market interaction described here results in Xcel Energy passing only the fuel costs from generating the energy to its customers, as the market buys and sells net to zero.[61]

[61] Ex. Xcel-4 at 4-5 (Detmer Direct).

55. This scenario is illustrated as follows:[62]

| **LOAD PURCHASE** | | Load | Purchased | | Load |
|---|---|---|---|---|---|
| | | MW | MW | $/MWh | Payment |
| Load | Day Ahead | 100 | 100 | $50.00 | $5,000 |
| Total | | 100 | 100 | | $5,000 |

| **GENERATION (GEN) SALES** | | Available | Cost | Sold | LMP | Revenue |
|---|---|---|---|---|---|---|
| | | MW | $/MWh | MW | $/MWh | Received |
| Gen 1 | Day Ahead | 30 | $50.00 | 10 | $50.00 | $500 |
| Gen 2 | Day Ahead | 90 | $25.00 | 90 | $50.00 | $4,500 |
| Total | | | | 100 | | $5,000 |

| **GEN COST** | | Available | Cost | Sold | Cost | Total |
|---|---|---|---|---|---|---|
| | | MW | $/MWh | MW | $/MWh | Cost |
| Gen 1 | Day Ahead | 30 | $50.00 | 10 | $50.00 | $500 |
| Gen 2 | Day Ahead | 90 | $25.00 | 90 | $25.00 | $2,250 |
| Total | | | | 100 | | $2,750 |

| | |
|---|---|
| Customer Cost | $2,750 |

56. As shown in this example, due to the "netting out" of sales and purchases in the MISO market, Xcel Energy customers benefit from the low-cost resources in the Company's generation portfolio, such as PINGP, as those resources effectively hedge customers' exposure to higher and more volatile LMP prices.[63]

### C. The Event And Subsequent Outage

57. On October 19, 2023, a team working on a cable-replacement project at PINGP inadvertently struck a DC power cable bundle containing control cables, severing those cables (the Event). Those cables control power to assets required to operate both units of PINGP at power. At the time of the Event, PINGP Unit 2 was offline, in a planned refueling outage, and the Event caused PINGP Unit 1 to also shut down.[64]

[62] Ex. Xcel-4 at 6, Table 1 (Detmer Direct).
[63] Ex. Xcel-4 at 10-11 (Detmer Direct).
[64] Ex. Xcel-1 at 5-6 (Krug Direct).

58. The affected direct current (DC) control cables included 30 cables of 5 shielded twisted conductor pairs each, approximately 1,300 feet long. The cables supply control power to assets required to operate both units of PINGP.[65]

59. The Company permanently replaced the control cables, rather than repairing the damaged portions. Unit 1 did not return to full service until January 30, 2024, meaning a total outage time for Unit 1 of 103 days following the Event. The work required to replace and test the control cables added 57 days to the length of the Unit 2 outage.[66]

60. No party to this action presented testimony that neither the total outage for Unit 1 nor the length of the extension of the Unit 2 outage was unreasonable given the nature of the work required to replace the cables.[67]

### D. The Company's Work Following The Outage

61. After the Event, the Company conducted an inspection of the cables and performed an Operational Decision-Making Issue Evaluation (ODMI) to assess various options for cable repair and replacement.[68] The ODMI determined that it was not feasible to use any of the cables in the area of the inadvertent cable cut due to the observed degradation of the cables.[69]

62. Based on this analysis, the Company determined that replacing the cables, rather than repairing them, was the best course of action. The Company's decision was based on the overall condition of the cable jackets, evidence of corrosion and degraded insulation.[70]

63. No party to this action provided testimony contesting the Company's position that replacement, rather than repair, was appropriate.[71]

64. The information gathered by the Company at the time of the Event and other information demonstrated that, given the condition of the cables in the area impacted by the Event, the DC control cables in this area would have required replacement in the future.

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[65] Ex. Xcel-1 at 5 (Krug Direct).
[66] Ex. Xcel-1 at 6-7, and Schedule 3 (Krug Direct).
[67] *See* Exs. OAG-1 (Lee Direct); OAG-4 (Lee Surrebuttal); DOC-1 (Golden Direct); DOC-2 (Golden Surrebuttal); XLI-1, 2, 5 (Andrews Direct); XLI-3, 4 (Andrews Surrebuttal).
[68] Ex. Xcel-10, Schedule 2 at 2 (Bible Direct).
[69] Ex. Xcel-10, Schedule 2 at 2 (Bible Direct).
[70] Ex. Xcel-1 at 5 (Krug Direct).
[71] *See* Exs. OAG-1 (Lee Direct); OAG-4 (Lee Surrebuttal); DOC-1 (Golden Direct); DOC-2 (Golden Surrebuttal); XLI-1, 2, 5 (Andrews Direct); XLI-3, 4 (Andrews Surrebuttal).

The Company sent portions of the damaged cables to the Electric Power Research Institute (EPRI) for testing and assessment. The cables had been buried in direct contact with soil, as was the practice in the early 1970s, and the Company also provided EPRI with a sample of the backfill in the area of the damaged cables for analysis. EPRI found that the control cable samples had been subject to moisture and overheating, and some locations had cracked jackets. EPRI also determined that the thermal resistance of the backfill was likely higher than planned for buried cables, which would have contributed to the cables overheating, resulting in cracked jackets and the concomitant potential for water intrusion.[72]

65. Company expert witness Mr. Carl Bible provided testimony that, based on the information about the state of the cables, the cables would have failed during future plant operation if their condition had not been discovered as a result of the Event, which would result in future plant alarms, spurious operation of equipment, and potentially tripping one or both units.[73]

66. Company expert witness Dr. Allen Hiser testified that replacement of the cables was a prudent measure that will ensure future reliability of the control cables and that the cables would likely have been subject to replacement during the second license renewal (SLR) operating period (the period of operation that occurs after a second license renewal).[74]

67. The Company intends to file a SLR Application for the Plant in late 2026.[75] Dr. Hiser opined that based on SLR guidance, as part of the SLR Application (SLRA) scoping process for the Plant, 20 percent of the DC control cables at the Plant (with a maximum of 25 cables) would be subject to sampling. Had the Event not occurred, the degraded cables discovered as a result of the Event may have been part of the 20 percent sampled as part of the SLRA process. Had these cables been included in the 20 percent sampled, it is highly likely that the degradation would be identified at that time. It is likely that corrective actions would include replacement of the cables, similar to the actions taken by the Company following the Event. This planned replacement, however, would likely have occurred as part of a planned dual unit outage.[76]

68. Dr. Hiser further testified that if the degraded cables were not included in the 20 percent, it is likely that the observed condition of the cables that were subject to testing and inspection would be used within the SLR aging management plan (AMP) to identify whether testing or inspection activities would be necessary for the unsampled DC control cables. If the condition of the cables that were tested and sampled was similar to that of the

[72] Ex. Xcel-13, Schedule 2 at 4-5 (Hiser Direct).
[73] Ex. Xcel-10, Schedule 2 at 3 (Bible Direct).
[74] Ex. Xcel-13 at 2 and Schedule 2 at 5, 6, n. 2 (Hiser Direct).
[75] Ex. Xcel-13, Schedule 2 at 3, 11 (Hiser Direct).
[76] Ex. Xcel-13, Schedule 2 at 13 (Hiser Direct).

cables that were inspected after the Event, it is likely that those additional cables would be inspected and tested, and the degradation would likely be discovered, resulting in a replacement of the degraded control cables during a planned dual unit outage.[77]

69. Dr. Hiser also considered a third scenario, in which the degraded cables were not included in the 20 percent tested and sampled, and the observed condition of the cables that were tested and inspected did not demonstrate a need for testing of the untested cables. In this case, it is likely that the cables that were discovered to be degraded after the Event would spontaneously fail at some time during the projected 80-year operating period. In this scenario, it is likely that the cables would then need to be replaced during an unplanned dual unit outage, similar to the scenario that occurred in the wake of the Event.[78]

70. The replacement of the degraded cables as a result of the Event had the effect of avoiding either a planned or unplanned dual outage in the future. No witness disputed this fact.[79]

71. The majority of the outages planned by the Company are single unit, rather than dual unit.[80] The Company took advantage of the unplanned dual unit outage caused by the Event not just to replace the damaged cables, but also to perform future planned work that required a dual unit outage, specifically the plant screenhouse stop rail guide inspection[81] and the cooling water system pipe replacement.[82]

72. By performing this work during the Event-caused dual unit outage, the Company avoided future outage time and the associated replacement power costs that would have been incurred. These projects required approximately 2,272 hours, meaning savings of approximately 2.2 outage days.[83]

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[77] Ex. Xcel-13, Schedule 2 at 13-14 (Hiser Direct).
[78] Ex. Xcel-13, Schedule 2 at 13-14 (Hiser Direct).
[79] *See* Exs. OAG-1 (Lee Direct); OAG-4 (Lee Surrebuttal); DOC-1 (Golden Direct); DOC-2 (Golden Surrebuttal); XLI-1, 2, 5 (Andrews Direct); XLI-3, 4 (Andrews Surrebuttal).
[80] Ex. OAG-1, Schedule 2 at 4 (Lee Direct).
[81] This project is denoted as "Inspect CT Stop Log Rail Guides" in Attachment B to the Company's Supplemental response to DOC IR No. 35, in Ex. Xcel-4, Schedule 2 at 9 (Detmer Direct).
[82] This project is denoted as "replace Elbow above CR-5-1" in Attachment B to the Company's Supplemental response to DOC IR No. 35, in Ex. Xcel-4, Schedule 2 at 9 (Detmer Direct).
[83] Ex. DOC-1, Schedule 1 at 2 (Golden Direct).

73. The Company and Department agree that the replacement power cost savings associated with conducting this work during the cable replacement amounts to approximately $500,000.[84]

### E. Estimating The Additional Costs Incurred And The Value Of Offsets And Benefits

74. During the outage, the Company needed to replace the energy that would have been provided by Prairie Island with other power – either from its own generation facilities or from purchases on the MISO market.[85]

75. To the extent this "replacement power" cost more than customers would have paid absent the Event and outage, and to the extent those incremental costs are not fully offset by other avoided costs or consideration of other customer benefits realized because of the outage, a refund of any remaining incremental impact on customers may be appropriate. This requires an analysis of the costs of procuring power that would have been generated by Prairie Island and an analysis of the value of offsets or benefits that accrued to Xcel Energy consumers from the Companies response to the Event, including offsets for pulled forward work and avoided future outage time.

#### 1. Power Costs

76. Determining the exact additional costs incurred would require precisely determining what Xcel Energy's costs *would* have been had an outage not occurred, essentially recreating a history that never happened. Due to the complexities and interactions within the Company's generation portfolio and the complexity of the MISO North energy market as a whole, it is not possible to precisely determine the additional power costs incurred as a result of any particular outage. Because many variables – including the outage itself – affect energy market prices, it is necessary to make reasonable assumptions, create a reasonable hypothetical "what if" scenario, and then compare the costs incurred in that "what if" scenario to the costs actually incurred to estimate the amount of additional power costs.[86]

77. The record contains one method for estimating any such additional power costs – the use of production cost modeling using the PLEXOS® production cost model.[87]

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[84] Ex. Xcel-3 at 6 (Krug Rebuttal); Ex. DOC-1 at 13 (Golden Direct).
[85] *See* Tr. at 56 (Detmer).
[86] Ex. Xcel-4 at 14 (Detmer Direct); Ex. DOC-1 at 6 (Golden Direct).
[87] Ex. Xcel-4 at 14 (Detmer Direct)

78. The record also contains an alternative approach that does not seek to estimate additional costs, but to instead estimate lost revenues and use that figure as a proxy for additional costs – the LMP calculation method (LMP Method).[88]

a. Production Cost Modeling

79. Xcel witness Mr. Detmer explained that production cost modeling is "a tool used to match supply (electric generation) with demand (customer load) to minimize overall system cost, while still honoring the operating characteristics of each electric generating unit[,]"and that production cost modeling software is now used extensively in the electric power industry to analyze and make decisions for today's large, complex power systems. This type of modeling is used "to forecast key values, such as the quantity of fuel needed for a specific generating unit in the future, what portfolio of electric generators will best minimize system pollutant emissions, or the expected economic value of a proposed transmission project."[89]

80. These models are also used to conduct backward looking analyses, such as evaluating previous decisions or events. When used with the goal of minimizing costs for electric power, as was done in this proceeding, the modeling tool incorporates a number of factors, including fuel costs, non-fuel operations and maintenance costs, generating unit minimum run times, maximum capacity at various generating units.[90]

81. The Company uses a variety of production cost models, depending on the specific purpose for which it is employed or the data to be analyzed.[91] For studies of power costs over a moderate term length of between one month and five years, Xcel Energy uses PLEXOS.[92]

82. PLEXOS is widely used in the industry, relied on by the Company and the Commission in multiple past cases, and used by the Company's power plant management, who depend on sound forecasts for a variety of uses including developing production-based budgets and scheduling maintenance.[93]

[88] Ex. XLI-1 at 12 (Andrews Direct); Ex. Xcel-1, Schedule 2 (Krug Direct).
[89] Ex. Xcel-4 at 11 (Detmer Direct).
[90] Ex. Xcel-4 at 11-13 (Detmer Direct).
[91] Ex. Xcel-4 at 14 (Detmer Direct).
[92] Ex. Xcel-4 at 14 (Detmer Direct).
[93] Ex. Xcel-8 at 7 (Detmer Rebuttal).

83. Using PLEXOS, the Company modeled the cost of replacement power in this proceeding by comparing a "base case" representing actual operations during the outage time (i.e., without PINGP) to a "change case" that included generation from PINGP.[94]

b. LMP Method

84. In contrast to production cost modeling, which develops a base and change case to determine the impact of the PINGP outage, the LMP Method does not attempt to determine the amount of additional cost that may have been incurred during the outage time, but rather assumes that the generation at all of Xcel Energy's other generation facilities would not change, with or without PINGP operating. The LMP Method assumes that, had it been available, all of PINGP's energy would have been sold on the MISO market at the LMP, with Xcel Energy's customers then getting credit for those sales, less PINGP's production costs. This method then uses this resulting "lost revenue" differential as a proxy for the replacement power costs.[95]

2. Value Of Offsets And Benefits

a. Offsets For Avoided Outages

85. The record establishes two different "offsets" for consideration in this proceeding: an offset for certain "pulled forward" work that shortened the time required for future outages; and an offset for an avoided extended future outage that would have been required for the cable replacement work performed during this outage.

86. The Company utilized PLEXOS production cost modeling to estimate the value to customers of avoiding these future outage times.[96]

87. The Department and Company agreed on the value of the "pulled forward work," as estimated using the PLEXOS model, and agreed that this should be considered as an offset to any replacement power costs.[97]

88. The Department disagreed that the future avoided extended outage should be considered in this proceeding.[98]

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[94] Ex. Xcel-4 at 16 (Detmer Direct); Ex. Xcel-8 at 3 (Detmer Rebuttal), which also notes that the Company's change case assumed perfect performance and maximum energy production from PINGP.
[95] Ex. XLI-2 at 11-12 (Andrews Direct).
[96] Ex. Xcel-4 at Schedule 2 (Detmer Direct).
[97] Ex. Xcel-3 at 6 (Krug Rebuttal); Ex. DOC-1 at 13 (Golden Direct).
[98] Ex. DOC-2 at 13 (Golden Surrebuttal).

89. Other parties disputed whether either offset should be considered, but no party provided an alternative means of valuing these offsets, should they be considered.

b. Benefits Of Historic Performance

90. Over the five-year period from 2018 through 2022, PINGP generated approximately 2,577 GWh above the Company's forecasted amount. Compared to the forecasted normal operating performance over that time period, this strong performance saved customers more than $50 million during that time.[99]

91. The Company has proposed a historical performance adjustment that seeks to recognize PINGP's past strong performance and the benefit it provided customers, and to avoid unduly penalizing the Company due to the additional power costs estimated above, which assumed perfect performance by PINGP. The Company developed a "performance adjustment" that it recommended be applied in determining any final refund amount, as discussed further, below. The Company stated that this "performance adjustment" recognizes PINGP's past strong performance and—rather than assuming this level of performance necessarily would have continued, which would have penalized the Company for its superior operation—holds the Company to an assumption of industry-median performance, by reflecting the fact that some level of outage is expected and reasonable.[100] All other parties opposed this adjustment.

## IV. DISPUTED ISSUES

### A. Appropriate Methodology To Estimate The Additional Power Costs Incurred Due To PINGP Being Offline

92. The Commission ordered this contested case proceeding, first, to "develop a record related to replacement power costs" incurred by Xcel Energy and paid by customers, due to the PINGP outage.[101]

93. There is only one analysis in this record which even seeks to calculate replacement power costs: the PLEXOS production cost modeling sponsored by Company witness Mr. Detmer. In contrast, the LMP Method supported by XLI and the Department attempts to quantify lost revenues due to PINGP's unavailability, using that as a proxy for replacement power costs, but does not actually perform an analysis of the difference in the total power costs incurred by the Company during the outage, compared to what those costs would have been had PINGP been operating.

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[99] Ex. Xcel-1 at 4-5 (Krug Direct); Ex. Xcel-4 at 21-22 (Detmer Direct).
[100] Ex. Xcel-1 at 12-13 (Krug Direct); Ex. Xcel-3 at 8 (Krug Rebuttal); Ex. Xcel-4 at 21-22 and Schedule 3 (Detmer Direct).
[101] NOTICE OF AND ORDER FOR HEARING at 3.

1. PLEXOS Modeling

94. The first element of the required replacement power cost analysis is determining what impact the PINGP outage had on the total power costs incurred by the Company and paid by customers during that outage. Because the Company provides the energy needed by its customers through both its own generation resources and the MISO market, and due to the complexities and interactions of the Company's system and the MISO market as a whole, these "replacement power costs" cannot be precisely determined.[102]

95. A reliable and reasonable estimate of these costs can be developed with production cost modeling that compares the costs the Company would have paid had PINGP been available (the change case) to the base case, representing actual operations without PINGP. The difference between the total costs in the change case and the total costs in the base case results in the "replacement power cost." [103]

96. The Company utilized the PLEXOS production cost model to develop the change case and base case results. The PLEXOS model is the same optimization software model the Company uses for planning, budgeting, and decision-making and the same model routinely relied on by the Company and Commission in fuel clause and other Commission proceedings, including proceedings that estimate replacement power costs.[104]

97. The Commission recently relied on PLEXOS modeling results in calculating replacement power costs due to an extended outage at the Company's Sherco 3 generating plant, with both the Department and OAG supporting that result.[105]

98. The PLEXOS model utilizes a complex time-series decision tree that seeks to determine the lowest cost series of decisions over the study period. To do this, the model requires power plant physical and cost characteristics (such as a unit's ability to run at full capacity and unit fuel costs), renewable generation forecasts, load forecasts, impacts from plant outages, and gas and electricity market forecasts.[106]

99. The Company developed the base case by inputting actual data, including actual fuel prices for each day of the outage, fuel transportation costs, heat rates (i.e., the efficiency of each generation unit, which impacts fuel consumption), start-up costs, and

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[102] Ex. Xcel-4 at 14-15 (Detmer Direct).
[103] Ex. Xcel-4 at 16 (Detmer Direct).
[104] Ex. Xcel-4 at 15 (Detmer Direct); Tr. at 57 (Detmer).
[105] *See* MPUC Docket Nos. E002/AA-18-373 *et al*, ORDER ADOPTING ADMINISTRATIVE LAW JUDGE REPORT AS MODIFIED, REQUIRING REFUND OF CERTAIN DISALLOWED REPLACEMENT POWER COSTS, AND REQUIRING FURTHER ACTION at 25-27 (Dec. 24, 2024); Ex. Xcel-1, Schedule 2 at 10, fn. 6 (Krug Direct).
[106] Ex. Xcel-4 at 15 (Detmer Direct).

variable operations and maintenance costs for every generator on the Xcel Energy system. The Company then ran the case such that every generator operated at its actual generation level for every hour of the outage period, producing a highly accurate representation of the Company's actual production costs and the Company then could run the model to develop the total system costs for energy over the outage period.[107]

100. Once this base case was established, the Company modified it to create the change case by making PINGP available over this same time period, assuming a 100 percent availability for every hour of every day of the outage period, and then allowed the model to redispatch generating units and to make additional sales, again to optimize the results, thereby minimizing overall system costs.[108]

101. Finally, subtracting the change case total system costs from the base case total system costs results in a total estimated incremental power costs for the Xcel Energy system of approximately $48.5 million, with $34.3 million attributable to the Minnesota jurisdiction.[109]

102. The Department and XLI both recommend that the Commission not rely on the Company's PLEXOS modeling estimate in this proceeding.

103. Department witness Dr. Steve Rakow acknowledged that "use of a production cost model such as PLEXOS is the best method to address the question in this docket: estimating the incremental cost of the PINGP outage."[110]

104. Nevertheless, Dr. Rakow stated that the Company's use of the model in this case was "internally inconsistent" and that the Company's model outputs "conflict with what is known in the real world."[111]

105. Dr. Rakow criticized the Company's PLEXOS modeling for not attempting to calculate and then incorporate a change in LMPs between the base case and the change case, claiming that holding LMPs equal in the two cases is "internally inconsistent" with model results that show an increase in generation from other Xcel Energy generating facilities from the change case to the base case.[112]

106. The Company responded that maintaining uniform LMPs is the norm in PLEXOS modeling, not some sort of error. The Company argued that Xcel Energy and the Commission routinely rely on PLEXOS modeling in fuel clause and other proceedings to

[107] Ex. Xcel-4 at 16 (Detmer Direct); Ex. Xcel-8 at 7-8 (Rebuttal Direct).
[108] Ex. Xcel-4 at 16 (Detmer Direct); Ex. Xcel-8 at 3, 11-13 (Detmer Rebuttal).
[109] Ex. Xcel-4 at 16 and Schedule 2, Attachment C (Detmer Direct).
[110] Ex. DOC-3 at 14 (Rakow Surrebuttal).
[111] Ex. DOC-3 at 5, 14 (Rakow Surrebuttal).
[112] Ex. Xcel-3 at 5 (Rakow Surrebuttal).

estimate replacement costs and those PLEXOS models include a variety of outages where LMPs are not changed during the outage periods.[113]

107. The Company also presented testimony that any change in LMPs due to the inclusion of PINGP is a secondary effect and difficult, if not impossible, to calculate. Therefore, rather than speculate as to the magnitude of any change in LMP, the Company's modeling assumed no change. The Company testified that, if anything, this assumption over-estimates replacement power costs. As Company witness Mr. Detmer noted, if the Company had incorporated some estimated impact on LMPs due to the addition of PINGP to the system, LMPs would have been lower in the change case, reducing the value of any remaining market transactions. Therefore, leaving LMPs unchanged between the two cases, as the Company did here, exaggerates the replacement power costs in customers' favor.[114]

108. Dr. Rakow also stated that the Company's model outputs "conflict with what is known in the real world." Dr. Rakow reviewed LMPs across MISO during the time of the outage and concluded that the LMP data "[did] not support an assumption that loss of PINGP's energy would be replaced by Xcel's own generation," as shown in the Company's PLEXOS modeling results.[115]

109. The Company responded that the generation at its other generation resources demonstrably increased during the time PINGP was off-line, as shown by a comparison of annual forecasted generation (that included PINGP generation) to actual generation at those plants during the PINGP outage, evidence that the loss of PINGP's energy was replaced by Xcel Energy's own generation.[116]

110. The Company stated that this increase in generation from Xcel Energy generating units, as shown in both the real world and in the Company's modeling results, is logical. As Mr. Detmer testified, Xcel Energy operates in a Narrow Constrained Area within the MISO North region. MISO's Independent Market Monitor (IMM) reporting confirms constraints as occurring and the MISO IMM designates an NCA when an area constraint binds more than 2,000 hours in a year. In its 2022 filing, the IMM states that the Minnesota region bound more than 4,000 hours, limiting the ability to transport power into or out of the region and meaning Xcel Energy is often price isolated and must address generation disruptions in the area with its own resources.[117]

[113] Tr. at 56-57 (Detmer).
[114] Ex. Xcel-8 at 4-5 (Detmer Rebuttal); Tr. at 57 (Detmer).
[115] Ex. DOC-3 at 13-14 (Rakow Surrebuttal).
[116] Tr. at 56 (Detmer).
[117] Tr. at 54-55 (Detmer).

111. The Company stated that its PLEXOS modeling results reflect this reality and align with what actually occurred during the PINGP outage, further demonstrating the reasonableness and reliability of the Company's replacement power cost estimate.

112. XLI also criticized the Company's PLEXOS modeling by questioning whether the Company appropriately set (or calibrated) the "base case," to produce an accurate representation of the Company's actual power costs during the study period.[118]

113. However, XLI did not identify specific alleged errors in the Company's development of the base case and in fact acknowledged that it incorporated the actual output from the generating units modeled.[119]

114. Similar to Department witness Dr. Rakow, XLI witness Mr. Brain Andrews argued that "the generation output of Xcel [Energy]'s other resources should have been largely unchanged" with or without the energy supplied by PINGP.[120]

115. The record conclusively demonstrates that the Company's base case inputs included actual fuel prices for each day of the outage, fuel transportation costs, heat rates, start-up costs, and variable operations and maintenance costs for every generator in the Xcel Energy system. These inputs then, together with the use of actual generation on an hour-by-hour basis, result in a highly accurate representation of the Company's power costs during the PINGP outage.[121]

116. The Administrative Law Judge finds that the record demonstrates the reasonableness of both the Company's base case and change case. Moreover, observing the "real world" impacts of losing PINGP generation during the outage supports the Company's PLEXOS model results, as the evidence shows that generation at Xcel Energy's other generating units increased. Therefore, the PLEXOS model results reasonably and reliably estimate the cost of replacement power during the PINGP outage of approximately $48.5 million, with $34.3 million attributable to the Minnesota jurisdiction.

2. The LMP Method

117. The Department and XLI recommend the Commission not use a production cost model in this proceeding, but instead estimate replacement power costs with the LMP Method – describing it as a "simpler approach . . . that determines the net revenue that

[118] Ex. XLI-2 at 4-5 (Andrews Direct).
[119] Ex. XLI-2 at 4 (Andrews Direct).
[120] Ex. XLI-2 at 3, 11 (Andrews Direct).
[121] Ex. Xcel-8 at 7-88 (Detmer Rebuttal).

would have been earned had [PINGP] been operating as usual" and stating that it can provide a "sufficiently reasonable" result.[122]

118. The LMP Method does not attempt to determine the incremental cost of power the Company incurred during the PINGP outage. Rather, it assumes that every kilowatt hour of energy that would have been produced by PINGP had it been operating, and operating 24 hours a day every day of the week, would have been sold at LMP prices on the MISO market.[123]

119. As Company witness Mr. Detmer testified, the LMP Method is a common but overly simplistic (and not merely "simpler") method for developing a proxy for replacement power costs. The Company often uses the LMP Method as a quick and simple estimation tool and used it in this docket to develop an initial estimate of PINGP's replacement power costs.[124]

120. Xcel Energy also acknowledged that the LMP Method can also be reasonable if the size of the facility at issue is small enough that other nearby resources would be unaffected by the facility's unavailability.[125] The Company stated, however, that the LMP Method has inherent limitations that make it ill-suited for the kind of robust replacement power cost analysis required in this case, where a 1000 megawatt baseload facility was unavailable for several weeks.[126]

121. The LMP Method fails to recognize that Xcel Energy customers are not always exposed to market prices, but to Xcel Energy's generation costs, which can be lower than market prices, particularly in the case of a low cost resource such as PINGP. Adding such low-cost resources back into the Company's portfolio means that the Company and customers will pay less for power, and sometimes substantially less, than paying market prices, as implied by the LMP Method.[127]

122. The LMP Method supported by the Department and XLI also assumes that had PINGP been operating, rather than off-line, every kilowatt hour produced at PINGP would have been sold on the MISO market at LMP pricing, allowing the LMP Method to estimate "the net revenue that would have been earned had [PINGP] been operating as usual." [128]

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[122] Ex. XLI-2 at 15 (Andrews Direct); Ex. DOC-3 at 19 (Rakow Surrebuttal).
[123] Ex. XLI-2 at 11-12 (Andrews Direct)
[124] Ex. Xcel-1, Schedule 2 (Krug Direct); Ex. Xcel-8 at 9 (Detmer Direct).
[125] Ex. Xcel-8 at 9 (Detmer Rebuttal).
[126] Ex. Xcel-8 at 9 (Detmer Rebuttal).
[127] *See* Ex. Xcel-4 at 4-10 (Detmer Direct) (discussing different scenarios and how those scenarios impact customer cost).
[128] Ex. XLI-2 at 15 (Andrews Direct) (emphasis added).

123. The Company further noted that, because the LMP Method assumes every kilowatt hour of power from PINGP would have been sold on the MISO Market at LMP pricing, the LMP Method assumes those other generating assets would have provided the exact same amount of production, with or without PINGP operating.[129]

124. Finally, the Company explained that, in order for the LMP Method to provide a reasonable estimate of the impact of the PINGP outage, all PINGP power produced during the outage would have had to have production costs below the LMP price in order to clear the market, and would not have had production costs below Xcel Energy's other generating facilities. Had PINGP had costs lower than those other units, PINGP power would have displaced this other, higher cost (but still below LMP priced) power.[130]

125. Real world data confirms that the LMP Method supported by the Department and XLI does not reflect what actually occurred on the Company's system. Xcel Energy's other generation resources increased production during the time PINGP was off-line, as shown by a comparison of the Company's forecasted generation (assuming PINGP generation was fully operational) to actual generation at those plants during the PINGP outage.[131]

126. The Administrative Law Judge finds that the LMP Method does not provide a reasonable proxy for the replacement power costs incurred due to the PINGP outage. The Administrative Law Judge further finds that the record demonstrates the Company's PLEXOS modeling provides the most reliable estimate of replacement power costs in this proceeding and quantifies those costs as $34.3 million.

### B. Offset Of Future Extended Outage Costs Due To The Company's Full Replacement Of The Impacted Cables

127. The Commission also ordered this contested case proceeding to develop a record regarding any offsets or benefits that should be considered in determining a final refund amount, if any.[132]

128. The Company provided testimony and supporting evidence that replacement of the impacted cables in 2023 avoided future outage costs that it recommended be considered as an offset. As discussed in the testimony of Company witnesses Mr. Bible and Dr. Hiser, the cables would have needed to be replaced at some point in the future,

[129] Tr. at 56 (Detmer).
[130] Tr. at 56 (Detmer); Xcel Energy Initial Brief at 32.
[131] Tr. at 56 (Detmer).
[132] NOTICE OF AND ORDER FOR HEARING at 3.

either as a result of a spontaneous failure or as a result of a corrective order during the SLR process, based on the discovered condition of the cut cables.[133]

129. The Company analyzed three possible scenarios where a future cable replacement might occur and proposes adopting the value of the most conservative scenario as an offset to the incremental power costs of the outage – in other words, the scenario most favorable to customers. That scenario assumed a planned replacement of the cables resulting from inspection and testing during the SLRA process and resulted in the lowest avoided replacement power costs of the scenarios presented. The Company explained that the scenarios leading to higher potentially avoided replacement power costs are not proposed by the Company but are instead provided as examples of other situations where cable replacement would be necessary in the future.[134]

130. Company witness Mr. Nicholas Detmer testified that the value of the avoided replacement power under the most conservative scenario is approximately $27.2 million on a Total Company basis (approximately $21 million for the Minnesota jurisdiction).[135]

131. The Department did not initially specifically address whether or not the Company was entitled to an offset for avoided replacement power costs, but Department witness Golden indicated that the Company might not be able to recover replacement power costs in the event of a spontaneous cable failure, because the Company's failure to inspect or test those cables prior to such a failure could be deemed imprudent.[136]

132. OAG witness Ms. Shoua Lee raised the same issue and also argued that the Company failed to show that this future cable replacement could not be paired with other necessary work in such a way as to avoid adding any time to the length of a future outage. Ms. Lee also questioned the allocator used by the Company, which was based on projected 2029 sales, because it was higher than the allocator used for 2023 and 2024, therefore increasing the share of the share of the avoided 2029 costs allocated to Minnesota.[137]

#### 1. Requirements, Guidance, Or Industry Standards For DC Control Cable Testing Or Inspection

133. OAG witness Ms. Lee argued that the Commission should not allow an offset for future avoided costs attributable to cable replacement in 2023 because the Company

[133] Ex. Xcel-14 at 2 (Hiser Rebuttal); Ex. Xcel-11 at 4 (Bible Rebuttal).
[134] Ex. Xcel-3 at 4 (Krug Rebuttal).
[135] Ex. Xcel-6 at 18 (Detmer Errata).
[136] Ex. DOC-1 at 11 (Golden Direct).
[137] Ex. OAG-1 at 13-15 (Lee Direct).

has not shown that it was prudent to not have already inspected and replaced a 50-year-old control cable buried in direct contact with the soil.[138]

134. Similarly, Department witness Mr. Golden argued that it is not clear that Xcel Energy would be entitled to recover replacement power costs in the two study scenarios that included spontaneous cable failure because it is not clear that it would be prudent to wait until a cable failed to replace it.[139]

135. Company witnesses Mr. Bible and Dr. Hiser each testified that there are no regulatory requirements, guidance or industry standards applicable to PINGP that would have required testing or inspection of the damaged DC control cables prior to the Event.

136. Specifically, Dr. Hiser testified that the NRC does not require any aging management for these cables during the license renewal (LR) term, and the Plant is currently in the LR term (the period from 40-60 years after initial licensing). Inspection is only warranted when circumstances indicate a need for testing or inspection, including a history of cable failures, water ponding in the area, or connected equipment not operating properly.[140]

137. Mr. Bible also testified to the lack of standards or requirements that would require testing or inspection of the cables, noting that the condition of the cables as revealed after the Event was not expected due to the lack of history of cable failures, the functioning of the equipment attached to the cables, and the lack of water ponding in the area.[141]

138. OAG witness Ms. Lee responded to the Company's testimony and argued that at some future time, the NRC's requirements might change to require testing or inspection of the DC control cables.[142]

139. Ms. Lee's position is speculative and irrelevant and that it is possible that regulations might change in the future, there is no possible scenario where regulations would change in such a way to require retroactive inspections or testing. Ms. Lee acknowledged this by stating that any future cable failure or replacement would need to be assessed under "the NRC standards and guidelines applicable at that time . . . ." Ms. Lee admitted at the Evidentiary Hearing that she was not aware of any pending change in NRC regulations or guidance governing the management of DC control cables, and that she

[138] Ex. OAG-1 at 13 (Lee Direct).
[139] Ex. DOC-1 at 11 (Golden Direct).
[140] Ex. Xcel-14 at 2 (Hiser Rebuttal).
[141] Ex. Xcel-11 at 4 (Bible Rebuttal).
[142] Ex. OAG-4 at 9 (Lee Surrebuttal).

specifically was not aware of any such change that would retroactively require a different management approach to such cables.[143]

140. In response to Mr. Golden, the Company stated that his testimony is largely irrelevant, as the Company is not proposing to seek recovery of the amounts associated with either of the spontaneous failure scenarios and calculated the appropriate offset based on replacement of the cables during the SLRA process.

141. Further, the Company presented evidence that it has conducted functional testing of the end components attached to the cables that were cut, and the results of those tests did not show any issues suggesting problems with the cables.[144]

142. The Administrative Law Judge finds that the record contains no evidence that the Company should have performed additional inspections or testing of the cables. The Administrative Law Judge also finds that such inquiry has no bearing on the calculation of offset proposed by the Company, which is based on identifying the need for cable replacement during the SLRA process.

2. Estimate Of Avoided Future Outage Length

143. OAG witness Ms. Lee argued that it is uncertain that future cable replacement could not be performed concurrently with other work during another planned outage and thus would not be a critical path project that drives the length of a future outage, questioning the Company's estimate of an additional 93 outage days in 2029.[145]

144. In response, Company witness Mr. Bible provided a thorough discussion of the sequencing of the cable replacement project, pointing out when concurrent projects could be conducted and referenced an illustrative timeline depicting these concepts.[146]

145. Mr. Bible testified that:

> Critical path work is the work that takes the longest, and at a nuclear facility, it is work [that] needs to be done in a particular sequence for nuclear safety reasons. Due to the necessary sequencing of such work, that work drives the overall length of the outage, and nuclear safety considerations determine what work can and cannot be performed concurrently.[147]

[143] Ex. OAG-4 at 9 (Lee Surrebuttal); Tr. at 133 (Lee).
[144] Ex. Xcel-14 at 3-4, Schedule 1 (Hiser Rebuttal).
[145] Ex. OAG-1 at 13-14 (Lee Direct).
[146] Ex. Xcel-11 at 6-7, Schedule 1 at 110 (Bible Rebuttal).
[147] Ex. Xcel-11 at 6 (Bible Rebuttal).

146. The evidence presented by Mr. Bible demonstrates that the cable replacement project is critical path work which requires a dual unit shutdown and must be completed in a particular sequence.[148]

147. Mr. Bible further testified that determining which work can be conducted concurrently at a nuclear plant is unquestionably an engineering issue.[149]

148. In response to discovery, the Company noted that refueling activities and major projects typically drive outage schedules, meaning that they are considered "critical path."[150]

149. By her own admission, Ms. Lee is not qualified to opine on engineering-related matters. During the Evidentiary Hearing, Ms. Lee admitted she had no basis to disagree with the Company's response on this point.[151]

150. The Administrative Law Judge finds that the evidence supports Xcel Energy's estimate of an additional 93 outage days if the Company decided to replace the cables during a planned 2029 outage.

3. Avoided Replacement Power Cost Allocator

151. In her Direct Testimony, OAG witness Ms. Lee questioned the use of a higher allocator than that applied in October 2023 and 2024 for the calculation of avoided replacement power costs.[152]

152. The Company responded and explained that a jurisdictional allocator for 2029 was calculated by the Company because the avoided replacement costs would have occurred in the future. The Company has historically calculated such allocators by allocating fuel costs to each state based on sales. The same method was employed with respect to the allocator used here, with the calculation being based on forecasted sales in 2029.[153]

153. The OAG continued to object to the calculation in Rebuttal and Surrebuttal Testimony, claiming that the forecasted load may not come on line as anticipated. Ms. Lee pointed to the requirement included in the Commission's most recent integrated resource plan (IRP) that the Company make a filing with a proposal for development of a new rate class or sub-class and tariff for super-large customer related to data center load in the future,

[148] Ex. Xcel-11 at 6 (Bible Rebuttal).
[149] Ex. Xcel-11 at 5 (Bible Rebuttal).
[150] Ex. OAG-1, Schedule 2 (Lee Direct).
[151] Ex. OAG-1 at 13 (Lee Direct); Tr. at 124, 132-33 (Lee).
[152] Ex. OAG-1 at 14-15 (Lee Direct).
[153] Ex. Xcel-3 at 5 (Krug Rebuttal).

suggesting that the Commission will closely monitor developments of data centers in the Company's service area.[154]

154. The Company responded that nothing about this requirement supports the OAG's stated concern regarding load, and that due to the nature of the proposed offset, estimates are necessary. The Company specifically addressed this issue at the outset of this proceeding by noting that the exact timing and duration of the avoided or shortened outages must be estimated and that a general estimate of replacement power costs if those outages actually occurred," and that "[w]hile these estimates are just that, the avoided costs are real benefits that customer will receive due to the work done by the Company during the outage."[155]

155. The Administrative Law Judge finds that the Company's use of a jurisdictional allocator for 2029 appropriately reflects that the avoided replacement costs would have occurred in 2029. The Administrative Law Judge agrees that due to the removed nature of the avoided costs, estimates are necessary and appropriate to value the benefits that customer will receive due to the work performed in 2023.

156. In sum the record shows that the Company's estimate of avoided power costs due to the avoided future cable replacement was conservative. Further, the record is clear that no party has contested that the cables at issue, in their degraded state, would have failed in the future had they not been discovered as a result of the Event.

157. The Administrative Law Judge finds that the Company demonstrated that the replacement of the cables in 2023 avoided the inevitable future power replacement costs. Using the Company's most conservative estimate based on replacement during the SLRA process, the Administrative Law Judge finds that the Company avoided an additional 93 outage days in 2029 and that it is appropriate to offset the replacement power costs incurred during the PINGP outage by approximately $27.2 million on a Total Company basis (approximately $21 million for the Minnesota jurisdiction).

### C. Offset Of Avoided Future Outage Related Costs Due To The Company Performing Additional Work Beyond The Cable Replacement

158. The Company used the unplanned dual unit outage to perform work that had been slated for a later planned outage. The Company presented evidence that by completing two of those projects during that outage, both of which would have required a dual unit

[154] Ex. OAG-4 at 12 (Lee Rebuttal); Ex. OAG-4 at 12 (Lee Surrebuttal).
[155] Ex. Xcel-4 at 17 (Detmer Direct).

outage, the Company avoiding 1,050 of labor hours per day over 2.2 days of future outage time, saving approximately $500,000 in future costs.[156]

159. Department witness Golden agreed with this calculation.[157]

160. The OAG claimed that the Company failed to establish that the pulled-forward work could not have been completed in future outages without lengthening that future outage period and that the Company's assumed labor hours per outage day used to calculate the saved outage days appeared to be arbitrary.[158]

1. Determination Of The Length Of The Future Avoided Outage Time

161. OAG witness Ms. Lee disagreed that the Company avoided 2.2 days of future outage time by pulling-forward critical path work. Ms. Lee testified that the pulled-forward projects could have been completed concurrently with other work scheduled, or work that may be eventually scheduled, for future outages.[159]

162. The Company elicited testimony from Ms. Lee during the Evidentiary Hearing that her written testimony ignored that the definition of "critical path work" involves not just the length of the project at issue, but the sequencing of that work as well. Ms. Lee further acknowledged that the relevance of sequencing of projects to whether or not a project is "critical path," is an "engineering issue" and that she therefore does not have an opinion on that issue. Ms. Lee admitted that she had not evaluated the nature of either of the pulled-forward projects, and that in any event she was not qualified to do so. Ms. Lee indicated that she does not know that the pulled-forward work could have been completed with other work, and instead, she "just raised the question."[160]

163. The Company bears the burden of proof to demonstrate that the refund due ratepayers should be offset by the value of the avoided outage days. The standard of proof for contested case hearings is preponderance of the evidence.[161]

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[156] Ex. Xcel-3 at 6 (Krug Rebuttal); Ex. DOC-1, Schedule 1 at 2 (Golden Direct). The Company pulled forward additional work during the outage and initially calculated the saved outage days at 8.1. After conducting additional analysis of the nature of the work that was "pulled forward" into the dual unit outage, however, the Company determined that the number of outage days saved was more properly calculated as 2.2 days. *Id.*

[157] Ex. DOC-2 at 2 (Golden Surrebuttal).

[158] Ex. OAG-4 at 2 (Lee Surrebuttal).

[159] Ex. OAG-1 at 9 (Lee Direct); Ex. OAG-4 at 2 (Lee Surrebuttal).

[160] Tr. at 126-27, 131-32 (Lee).

[161] Minn. R. 1400.7300, subp. 5.

164. Ms. Lee's conjecture that the two projects identified could be performed concurrently with some as yet unidentified work is not evidence, and the Company is not required to "definitively" demonstrate that no such circumstance could exist in the future.

165. The Administrative Law Judge finds that the OAG presented no evidence that the pulled-forward work could be completed concurrently with other future work. Ms. Lee asserted only her non-expert supposition that there could be some other work in the future that required a dual unit outage, which might cause the two pulled-forward projects to not be critical path.

166. The Administrative Law finds that Xcel Energy met its burden of proof to and demonstrated the reasonableness of its estimate of 2.2 days of future outage time by pulling forward critical path work.

2. Estimated Labor Hours Per Outage Day And Calculation of Total Days Of Avoided Outage

167. The Company based its estimate of 1,050 labor hours per outage day on the amount of labor hours spent per day during the dual unit outage resulting from the Event.[162]

168. The OAG disagreed with the Company's estimate of 1,050 labor hours per outage day, arguing that it was "arbitrary." Ms. Lee argued that the relevant outage for consideration is the future outage from which this work was pulled forward rather than the October 2023 outage. Ms. Lee relied on information from the Company showing higher numbers of labor hours per day for earlier outages, and claims that the Company's use of data from the October 2023 dual unit outage improperly inflates the numbers of outage days avoided.[163]

169. The Company explained that the outages Ms. Lee relied on for her comparison were all single unit outages, and the pulled-forward work identified by the Company as leading to avoided outage days requires a dual unit outage. The Company argued that Ms. Lee's comparison is thus not appropriate and that, as noted by Company witness Mr. Bible, using data from an actual outage to calculate avoided days is not arbitrary.[164]

170. The Company also noted that its calculation of avoided outage days did not include the additional outage days that would be required to shut down and restart the

[162] Ex. Xcel-4, Schedule 2 at 9 (Detmer Direct); Ex. Xcel-11 at 8 (Bible Rebuttal).
[163] Ex. OAG-1 at 10-11 (Lee Direct).
[164] Ex. OAG-4 at 6 (Lee Surrebuttal); Ex. Xcel-11 at 7-8 (Bible Rebuttal); Tr. at 133 (Lee).

reactor in its estimate, and thus its estimate of avoided outage days as a result of pulling forward two projects that would require a dual unit outage was conservative.[165]

171. No party contested that the avoided outage days excluded the additional days required to shut down and restart the reactor.

172. A court cannot rely on speculation in making key findings in support of its ruling.[166]

173. The OAG offered unsupported speculation in support of its position. The only evidence relevant to the pulled-forward work establishes that the work would have been required to be completed during a dual unit outage, and that the two projects would have taken approximately 2.2 outage days to perform.[167]

174. The Administrative Law Judge finds that 2.2 future outage days were avoided because the Company conducted the work during the unplanned dual unit outage resulting from the Event. The Commission should accept the determination of the Department and Xcel to find that 2.2 days of outage time were avoided as a result of the pulled-forward work.

### D. PINGP's Historic Performance

175. The Company argued that the Commission should consider the substantial benefits Xcel Energy customers have received from the Company's operation of PINGP, resulting in strong historical performance compared to forecasted or industry-average performance.[168]

176. The Company explained that this strong performance was critical to customers in periods of extreme weather, including the 2019 polar vortex, the 2021 Winter Storm Uri, and others. The record supports the Company's positions and demonstrates that over the five year period from 2018 through 2022, not only did PINGP outperform the industry average, it generated approximately 2,577 GWh above the Company's forecasted amount of energy. This strong performance, compared to normal operating performance over that time period, benefited Xcel Energy customers by more than $50 million and no party disputes these benefits.[169]

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[165] Ex. Xcel-11 at 8-9 (Bible Rebuttal).
[166] *Mast v. County of Fillmore*, 993 N.W.2d 895, 910 (Minn. App. 2023).
[167] Ex. Xcel-11 at 7-9 (Bible Rebuttal); Ex. DOC-1, Schedule 1 at 2 (Golden Direct).
[168] Ex. Xcel-1 at 12 (Krug Direct).
[169] Ex. Xcel-1 at 4-5 (Krug Direct); Ex. Xcel-3 at 7 (Kurg Rebuttal); Ex. Xcel-4 at 21-22 (Detmer Direct).

177. The Company acknowledged that due to the impact of the Event, extending this historical performance review to cover the period of the outage shows that PINGP exceeded the industry-median outage hours. The Company explained that, because the industry also experienced outages at that time, the ultimate determination of any appropriate refund due to the PINGP outage should account for the fact that perfection is not achievable by incorporating a comparison of historical performance to industry standards and "benchmarking" PINGP performance to industry-median performance.[170]

178. Company witness Mr. Detmer testified that benchmarking PINGP performance to industry-median performance results in a recommended "historic performance" adjustment of 51 percent, to be applied to any net refund amount.[171]

179. The Department, OAG, and XLI opposed benchmarking PINGP performance.[172]

180. The Administrative Law Judge finds that the Company's proposal to incorporate a comparison of historical performance to industry standards is reasonable. The Administrative Law Judge also finds that the use of the most recent five-year period, including the outage resulting from the Event appropriately balances the benefits to Xcel Energy customers and the impacts from the Event. The Administrative Law Judge recommends that the Commission apply an adjustment of 51 percent to the net refund amount.

### E. Underspent Maintenance Expense

181. The Department argued in its Initial Brief that the any refund should be inflated by $51.8 million to reflect an "underspent" nuclear generation maintenance expense between 2018 and 2022.[173]

182. The Department's proposal is beyond the scope of this contested case proceeding. The Commission established that the scope of the contested case is "limited to the refund owed to ratepayers for the costs that flow through the fuel-clause adjustment report" along with "any benefits and offsets in determining the appropriate refund."[174]

183. Due to this limited scope of the contested case proceeding, there is no record supporting the Department's allegations. The record lacks any development or analysis of

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[170] Ex. Xcel-1 at 13 (Krug Direct); Ex. Xcel-3 at 7-8 (Krug Rebuttal); Ex. Xcel-4 at 24 (Detmer Direct).
[171] Ex. Xcel-4 at 24 (Detmer Direct).
[172] Ex. DOC-2 at 3 (Golden Direct); Ex. OAG-1 at 18 (Lee Direct); Ex. XLI-4 at 10-11 (Andrews Surrebuttal).
[173] Department Initial Brief at 23.
[174] CLARIFYING ORDER at 4.

whether the alleged underspend occurred or, if there was an underspend, any analysis of the reasons or causal factors. Further, if there was an underspend, there is no record establishing a causal connection to the Event.

184. The Administrative Law Judge finds that the record does not support the Department's allegations or proposed inflation of any replacement power refund.

### F. Recovery Of Company's Costs Of Participating In A Commission-Ordered Proceeding

185. The Department and OAG argued that the Company should be precluded from recovering the costs of participating in this proceeding.[175]

186. The Department argued that denying Xcel Energy recovery of it litigation expenses is consistent with the "American rule" that parties pay their own litigation costs, and that the Company's litigation expenses have no bearing on its obligations to provide adequate, efficient, and reasonable service. The Department argued that the Commission should not allow the recovery of costs that would encourage utilities to litigate every refund.[176]

187. The OAG similarly argued that the Company's litigation expenses are not related to furnishing adequate electric service.[177]

188. The arguments of the Department and OAG are not supported by the procedural posture of this matter. This contested case was ordered by the Commission because the Commission concluded that "[c]onsidering the current record . . . it is unable to determine the appropriate ratepayer refund amount resulting from Xcel's imprudence."[178]

189. The Commission clarified that it expected:

> the contested case will develop a record related to replacement power costs and the appropriate amount of any refund of costs that flow through the fuel-adjustment mechanism [and] the contested case may develop the record on whether any customer benefits or offsets should be considered in the determination of any appropriate refund amount.[179]

190. The clarifying order included the following order points:

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[175] Department Initial Brief at 24-26; OAG Initial Brief at 35-37.
[176] Department Initial Brief at 25-26.
[177] OAG Initial Brief at 36.
[178] NOTICE OF AND ORDER FOR HEARING at 8.
[179] CLARIFYING ORDER at 4.

> 2. The Commission grants the Department's request for clarification and adopts the amendments to the November 15, 2024 order shown on pages 5–6 of the Department's December 5, 2024 filing, clarifying that the contested case issues are limited to the refund owed to ratepayers for costs that flow through the fuel-clause adjustment report. In addition, the Commission also clarifies that parties should address other appropriate cost adjustments related to the October 2023 outage at Prairie Island, such as the impact of de-rating on capacity costs and insurance costs, in Xcel's currently pending general rate case for electric service, Docket E-002/GR-24-320.
>
> 3. The Commission further clarifies that the contested case shall also consider any benefits and offsets in determining the appropriate refund and consider whether imprudence by Xcel Energy resulted in customers paying more for power than they otherwise would have paid such that a refund of power costs is appropriate.[180]

191. The Administrative Law Judge finds that, as a regulated utility, the Company is required to comply with Commission orders. The Department's and OAG's disagreement with the position taken by the Company is not a basis for a disqualification of cost recovery.

192. The Administrative Law Judge also finds that the Department's and OAG's reliance on the "American rule" and authority related to recovery of attorneys' fees in litigation conducted in the courts is misplaced. This is not a situation where the Company chose to initiate or defend a piece of civil litigation. The Company was ordered by its regulating body, the Commission, to develop a record in a contested case that explicitly included consideration of offsets and benefits.

193. The Administrative Law Judge finds that there is no basis to accept the Department's and OAG's proposal to deny recovering the costs of participating in this proceeding.

### G. Refund Calculation

194. Fashioning a reasonable remedy in this case requires recognizing the totality of the circumstances for both customers and the Company. With respect to PINGP, that means beginning with the most reasonable and reliable estimate of the Minnesota jurisdiction replacement energy costs ($34.3 million) based on the Company's estimate using the PLEXOS model.[181]

[180] CLARIFYING ORDER at 4.
[181] Ex. Xcel-4 at 14-16 and Schedule 2 (Detmer Direct); Tr. at 53 (Detmer).

195. It is then appropriate to recognize the reasonable actions the Company took during the outage to minimize future outages and the associated costs ($0.5 million for the "pulled-forward" work and $21 million for the avoided extended outage).[182] Consideration of these offsets results in a refund of $12.8 million.

196. Finally, considering the customer benefit of Xcel Energy's superior operation of the plant for years prior to the Event, and to recognize that the perfect performance is not the standard for a power plant such as PINGP, it is reasonable to apply a historic performance adjustment of 51 percent to the net refund amount.[183] Application of that adjustment resulted in the Company recommending a refund of $7.4 million.[184]

197. After this full consideration of the costs, offsets and benefits, the records supports a Commission order requiring a refund to customers of $7.4 million to $12.8 million, plus interest at the prime rate.

## CONCLUSIONS OF LAW

1. The Commission and the Administrative Law Judge have jurisdiction to consider this matter pursuant to Minn. Stat. §§ 14.50, 216B.03.

2. The Commission has complied with all procedural requirements of law and rule, and the parties have had notice and an opportunity to fully participate in this proceeding. Therefore, this matter is properly before the Commission and the Administrative Law Judge.

3. Every rate made, demanded, or received by a public utility must be just and reasonable.[185]

4. The burden to prove the reasonableness of recovery of replacement power costs rests on Xcel Energy.[186]

5. The parties to this proceeding have established that a refund of $7.4 million is just and reasonable.

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[182] Ex. Xcel-3 at 6 (Krug Rebuttal); Ex. DOC-1 at 13 (Golden Direct); Ex. Xcel-6 at 18 (Detmer Errata); Tr. at 53 (Detmer).
[183] Ex. Xcel-3 at 9 (Krug Rebuttal).
[184] The Company noted an error in its original calculation of the $7.4 million. However, because correcting that calculation resulted in a smaller refund amount, the Company continued to support its original $7.4 million recommendation as a just and reasonable refund amount. *See* Xcel Initial Brief at 45.
[185] Minn. Stat. § 216B.03.
[186] Minn. Stat. § 216B.16, subd. 4.

Based on the Findings of Fact and Conclusions of Law, the Administrative Law Judge makes the following:

## RECOMMENDATION

1. For all of the reasons discussed above, a full analysis of the impact of the PINGP outage on customers demonstrates that the overall net impact of the outage on customers is approximately $7.4 million, plus interest. The just and reasonable outcome of this proceeding is for the Company to refund customers that amount.

Dated:_____

KIMBERLY MIDDENDORF
Administrative Law Judge

## NOTICE

Notice is hereby given that exceptions to this Report, if any, by any party adversely affected must be filed under the time frames established in the Commission's rules of practice and procedure, Minn. R. 7829.2700 and 7829.3100, unless otherwise directed by the Commission. Pursuant to Minn. R. 7829.2700, subp. 3, the parties will be granted an opportunity for oral argument before the Commission prior to its decision. The Commission will make the final determination of the matter after the expiration of the period for filing exceptions, or after oral argument, if an oral argument is held.

The Commission may, at its own discretion, accept, modify, or reject the ALJ's recommendations. The recommendations of the ALJ have no legal effect unless expressly adopted by the Commission as its final order.

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