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

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

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

*In the Matter of Xcel Energy's Petition for Approval
of its 2023 Annual Fuel Forecast and Monthly Fuel Cost Charges*

**INITIAL BRIEF
OF THE OFFICE OF THE ATTORNEY GENERAL—
RESIDENTIAL UTILITIES DIVISION**

November 25, 2025

TABLE OF CONTENTS

INTRODUCTION1

STATEMENT OF FACTS1

I. THE PRAIRIE ISLAND NUCLEAR GENERATING PLANT1

II. XCEL WORKERS CUT THROUGH BURIED CABLES AT PRAIRIE ISLAND, CAUSING AN EXTENDED PLANT OUTAGE.2

III. INSPECTION OF THE SEVERED CABLES REVEALS PREEXISTING DAMAGE TO THE CABLE JACKETS CAUSED BY OVERHEATING.....4

IV. PRAIRIE ISLAND’S OUTAGE CAUSES XCEL TO INCUR REPLACEMENT-POWER COSTS, WHICH XCEL PASSES ON TO RATEPAYERS.....9

V. THE COMMISSION FINDS THAT XCEL IMPRUDENTLY CAUSED THE OUTAGE AND REFERS THE CASE TO THE COURT OF ADMINISTRATIVE HEARINGS TO DEVELOP THE RECORD ON REPLACEMENT-POWER COSTS.10

LEGAL STANDARD.....11

ARGUMENT.....12

I. THE COMMISSION SHOULD REQUIRE XCEL TO REFUND \$40.6 MILLION IN REPLACEMENT-POWER COSTS.....13

II. THE COMMISSION SHOULD REJECT XCEL’S PROPOSED OFFSETS.....16

A. The Commission Should Reject Xcel’s “Supplemental Work” Offset.18

B. The Commission Should Reject Xcel’s “Avoided 2029 Costs” Offset.....20

1. Xcel may not offset a customer refund based on Xcel’s efforts to remedy its own imprudence.....21

2. The “avoided 2029 costs” offset depends on numerous speculative assumptions.....22

a. The “avoided 2029 costs” offset is based on an event that Xcel’s own witness testified has a less-than-20-percent chance of occurring.....23

b. Xcel assumes that, if the control cables were not inspected and replaced because of SLR, they would have inevitably failed due to degradation, and this failure would have occurred in 2029.24

c.	Xcel assumes that a future control-cable replacement would not be caused, in whole or part, by Xcel’s own imprudence.	26
d.	Xcel assumes that the cable replacement would have been critical path in a future outage.	28
C.	Xcel Overstates Minnesota’s Share of the “Supplemental Work” and “Avoided 2029 Costs” Offsets.....	30
D.	The Commission Should Reject Xcel’s Historic Performance Adjustment.	32
III.	XCEL SHOULD BEAR ITS OWN COSTS FOR THE CONTESTED CASE.....	35
	CONCLUSION.....	37

INTRODUCTION

In October 2023, Xcel Energy caused an extended outage at the Prairie Island nuclear power plant by failing to properly oversee excavations at the plant. Its workers struck buried cables that were not shown on the maps they had been given. Fortunately, no one was hurt, and the plant’s safety-related backup systems performed as expected, preventing a nuclear incident. With the plant offline for repairs, however, Xcel’s ratepayers experienced millions of dollars in additional wholesale power purchases, and foregone revenues, from the plant’s missing generation.

The Commission found that Xcel had acted imprudently and referred the case to the Court of Administrative Hearings to develop the record on the refund needed to make ratepayers whole for the outage’s costs. Rather than accepting responsibility for its imprudent actions, Xcel concocts several dubious theories for why it should be able to hold back more than 80 percent of the incremental energy costs it collected from ratepayers during the outage. The ALJ and the Commission should require Xcel to refund these costs in full and reject the offsets by which Xcel seeks to avoid accountability for the harm caused by its imprudence.

STATEMENT OF FACTS

I. THE PRAIRIE ISLAND NUCLEAR GENERATING PLANT

Prairie Island Nuclear Generating Plant (“Prairie Island” or “the plant”) is a two-unit nuclear power plant located on an island in the Mississippi River near Red Wing, Minnesota.¹ The plant has been in service for over 50 years, with Unit 1 commencing operation in 1973 and Unit 2 in 1974.² Prairie Island’s generating units are separately licensed by the federal Nuclear

¹ Ex. OAG-1 at 2 (Lee Direct).

² Ex. Xcel-2 at 4 (Krug Direct).

Regulatory Commission (NRC).³ The NRC renewed both licenses in 2011, and the current licenses expire in 2033 and 2034.⁴ Xcel plans to apply to the NRC next year for a subsequent license renewal that would allow the units to operate until 2053 and 2054.⁵

II. XCEL WORKERS CUT THROUGH BURIED CABLES AT PRAIRIE ISLAND, CAUSING AN EXTENDED PLANT OUTAGE.

In October 2023, Xcel began a project to replace one of the power cables that connect Prairie Island to a nearby electrical substation.⁶ The project, conducted by supplemental workers from one of Xcel's nonnuclear divisions, involved horizontal directional drilling to create an underground path for the new cable.⁷

On the morning of October 19, with Unit 1 operating at 100 percent power and Unit 2 offline for scheduled refueling, the nonnuclear workers began to bore a hole in preparation for their fifth conduit pull.⁸ The workers deviated from the planned drilling path, which had been surveyed with ground-penetrating radar to ensure it was clear of other infrastructure, and followed a new path that had not been surveyed.⁹ They struck a bundle of buried cables, severing them and causing an outage.¹⁰

The cables that the workers had severed were low-voltage direct-current cables, known as "control cables," that supply control power to equipment essential to the operation of both Prairie Island generating units.¹¹ A total of 30 control cables run approximately 1,300 feet in a common

³ See Ex. Xcel-13, sched. 2 at 3 (Hiser Direct).

⁴ Ex. Xcel-13, sched. 2 at 3 (Hiser Direct).

⁵ Ex. Xcel-13, sched. 2 at 3 (Hiser Direct).

⁶ Ex. OAG-7 at 5, 7 of 14.

⁷ *Id.*; Ex. OAG-2, SL-D-1 at 1 (Lee Direct Schedules).

⁸ Ex. OAG-7 at 7 of 14.

⁹ See PUC Agenda Meeting on 2024-09-19, <https://minnesotapuc.granicus.com/player/clip/2421> (statement begins at 2:18:00).

¹⁰ Ex. OAG-7 at 7 of 14; Ex. Xcel-2 at 5 (Krug Direct).

¹¹ Ex. OAG-2, SL-D-5 at 1–2 (Lee Direct Schedules).

trench from the Prairie Island substation to the plant.¹² The severed control cables were original to the plant and had been in service for approximately 50 years as of October 2023.¹³ They were buried in direct contact with the soil without a conduit or other protective enclosure, as was common practice in the early 1970s.¹⁴

Severing the control cables caused multiple substation breakers to open, which in turn caused Unit 1's turbine and reactor to trip offline, all non-safety-related busses to lose power, and backup cooling systems to kick in.¹⁵ The incident precipitated a months-long forced outage¹⁶ of both Prairie Island units while Xcel worked to replace the severed cables.¹⁷ Unit 1 would ultimately return to service at the end of January 2024 and Unit 2 at the beginning of March 2024.¹⁸

In a March 2024 report to the NRC, Xcel described the root cause of the October 2023 incident as “weakness in the Excavation Permit approval process as well as the inadequate oversight of the non-nuclear supplemental workers performing HDD [horizontal directional drilling] work.”¹⁹

With regard to permit approval, Xcel explained that “[s]ite personnel reviewing and approving the permit were not adequately intrusive to ensure that all interferences had been

¹² Ex. Xcel-5, sched. 2 at 2 of 12 (Detmer Direct).

¹³ See Ex. Xcel-14, sched 1. at 3–4 (Hiser Rebuttal); Ex. DOC-6 at 2.

¹⁴ Ex. Xcel-10, sched. 2 at 3 (Bible Direct).

¹⁵ Ex. OAG-7 at 5 of 14.

¹⁶ A “forced outage,” also called an “unplanned outage,” refers to the situation where a generator experiences an outage that the utility had not planned. By contrast, a “planned outage” is an outage that is planned in advance, typically to conduct maintenance activities that cannot be completed with the plant running.

¹⁷ See Ex. OAG-1 at 3 (Lee Direct).

¹⁸ Ex. DOC-1 at 3 (Golden Direct).

¹⁹ Ex. OAG-7 at 7 of 14.

properly identified.”²⁰ Specifically, Xcel did not survey the drilling area using ground-penetrating radar.²¹ Had it done so, it “would have identified the interference with the DC cables.”²²

With regard to inadequate oversight, Xcel explained that “procedural weaknesses and poor communication between site departments allowed the HDD work to continue without a clear understanding of which site department was responsible for providing oversight to the HDD crew.”²³ As a result, the work progressed without “controls in place that would be expected for work at a nuclear plant.”²⁴ More specifically, “approved work plans were not always available at the work site and approved construction drawings for HDD work were not updated when changes were made in the field.”²⁵

As Xcel’s counsel would later explain at a September 2024 Commission hearing,

[E]ven though the path that was planned for this line had been surveyed, the individuals in the field realized, while they were doing the activity, that they needed to adjust the path. And they adjusted the path. And they called—they brought in the project engineer, who looked at maps. And for whatever reason, that project engineer believed that the maps that he was looking at indicated that at the depth they were running, this was clear. And it didn’t indicate that, because we had only surveyed the original path.²⁶

III. INSPECTION OF THE SEVERED CABLES REVEALS PREEXISTING DAMAGE TO THE CABLE JACKETS CAUSED BY OVERHEATING.

In the immediate aftermath of the incident, Xcel inspected the control cables and found “evidence of corrosion, and degraded insulation.”²⁷ Xcel determined that the condition of the cables put them at risk of water intrusion and therefore opted to permanently replace the control

²⁰ Ex. OAG-7 at 7 of 14.

²¹ Ex. OAG-7 at 7 of 14.

²² Ex. OAG-7 at 7 of 14.

²³ Ex. OAG-7 at 7 of 14.

²⁴ Ex. OAG-7 at 7 of 14.

²⁵ Ex. OAG-7 at 7 of 14.

²⁶ PUC Agenda Meeting on 2024-09-19, <https://minnesotapuc.granicus.com/player/clip/2421> (statement begins at 2:18:00).

²⁷ Ex. Xcel-2 at 5 (Krug Direct).

cables rather than simply repairing the portion that it had damaged.²⁸ Xcel also asked the Electric Power Research Institute (EPRI) to conduct a forensic evaluation to determine the probable causes of the cable degradation.²⁹

Figure 1, below, displays the cross-section of one of these control cables. As the figure shows, a control cable comprises five twisted pairs of copper conductors enclosed in chlorinated polymer insulation of various colors.³⁰ The conductors are further separated by a fiber fill and surrounded by a tinned copper foil shield and a common neoprene jacket.³¹

**Figure 1 –
Control Cable Cross-Section³²**



²⁸ Ex. Xcel-2 at 5–6 (Krug Direct).

²⁹ Ex. OAG-5 at 10 of 16 (EPRI Report – Final).

³⁰ Ex. OAG-5 at 10 of 16.

³¹ Ex. OAG-5 at 10 of 16.

³² Ex. OAG-5 at 12 of 16 fig.2 (EPRI Report – Final).

EPRI requested that Xcel provide “long continuous lengths of cable” to allow EPRI to perform electrical tests and observe the relative locations of the degradation.³³ Xcel, however, provided cable pieces cut to lengths of only three to four feet, making it impossible for EPRI to conduct meaningful electrical tests.³⁴ Xcel also failed to mark the pieces to allow EPRI to establish the interrelationship between them.³⁵ This failure, and the lack of any manufacturer markings on the jacket, made it impossible for EPRI to reassemble the full cable length or determine where on the cable the overheating occurred.³⁶

**Figure 2 –
Cable and Soil Samples Received from Xcel³⁷**



³³ Ex. OAG-5 at 10 of 16.

³⁴ Ex. OAG-5 at 10, 14–15 of 16.

³⁵ Ex. OAG-5 at 10 of 16.

³⁶ Ex. OAG-5 at 10, 16 of 16.

³⁷ Ex. OAG-5 at 11 of 16, fig.1.

There were also problems with the soil sample that Xcel provided to EPRI. EPRI had requested that the sample be “hermetically sealed in Tupperware-like containers” to preserve the compaction and moisture levels present in the soil.³⁸ Xcel, however, provided the soil in an unsealed plastic bag.³⁹ Given the unsealed container and the amount of time the sample was in transit, EPRI found it “unlikely that the local conditions could be reconstituted from this sample and, thereby, provide meaningful thermal resistance information.”⁴⁰

The information that EPRI was able to glean from the soil sample, however, suggested that it was a less-than-ideal fill material for direct-buried cables. Specifically, EPRI found that the soil was largely composed of “fine sand of similar particle size” and had a low moisture content.⁴¹ This information suggests that the soil’s “thermal resistivity was higher than planned for buried cables.”⁴² Instead of fine sand, a good thermal backfill for buried cables should include a range of particle sizes.⁴³ The low moisture level of the soil sample could also lead to higher-than-planned thermal resistivity—instead, a “controlled level of moisture” is desirable.⁴⁴

EPRI’s inspection of the cable samples uncovered evidence of overheating and pyrolysis,⁴⁵ supporting its hypothesis that the soil’s thermal resistivity was higher than planned for buried cables. First, several of the cable pieces displayed copper oxide at the cut surfaces, indicating likely exposure of the conductor to moisture and chlorine.⁴⁶ Polymer insulation can release chlorine through pyrolysis if it reaches a high enough temperature, and since no other source of

³⁸ Ex. OAG-5 at 10 of 16.

³⁹ Ex. OAG-5 at 10 of 16.

⁴⁰ Ex. OAG-5 at 10 of 16.

⁴¹ Ex. OAG-5 at 10–11 of 16.

⁴² Ex. OAG-5 at 11 of 16.

⁴³ Ex. OAG-5 at 11 of 16.

⁴⁴ Ex. OAG-5 at 11 of 16.

⁴⁵ See Ex. OAG-5 at 11–16 of 16 (reviewing cable condition).

⁴⁶ Ex. OAG-5 at 11 of 16.

chlorine was present, this indicates that the control cable overheated.⁴⁷ Second, the jackets of 5 out of the 56 cable pieces were cracked, and the jackets of another 6 displayed heat damage.⁴⁸ These defects in the cables jacket suggest, again, that the control cables were subjected to overheating.⁴⁹

**Figure 3 –
Control Cable Jacket Defects⁵⁰**



Cracked Jacket



Heat Damage

EPRI's report links the degradation of the control-cable jackets to the resistivity of the soil the cables were buried in. It notes that "soil resistivity can greatly impact cable longevity."⁵¹ If the soil around the control cables is dry and not compacted well, its thermal resistivity would be elevated and could lead to cable overheating and hardening of the jacket.⁵² This in turn could cause cracks to form that would allow moisture to penetrate the jacket, further damaging the internal conductors.⁵³

⁴⁷ Ex. OAG-5 at 11 of 16.

⁴⁸ Ex. OAG-5 at 12 of 16.

⁴⁹ Ex. OAG-5 at 14 of 16.

⁵⁰ Ex. OAG-5 at 14 of 16, fig.5.

⁵¹ Ex. OAG-5 at 14 of 16.

⁵² Ex. OAG-5 at 14 of 16.

⁵³ Ex. OAG-5 at 14 of 16.

IV. PRAIRIE ISLAND’S OUTAGE CAUSES XCEL TO INCUR REPLACEMENT-POWER COSTS, WHICH XCEL PASSES ON TO RATEPAYERS.

When a generation asset like Prairie Island goes offline, Xcel must procure energy from other sources to continue serving its customers.⁵⁴ This energy can come from Xcel’s other power plants, bilateral purchases from an independent power producer, or purchases on the Midcontinent Independent System Operator’s (MISO) wholesale market.⁵⁵ Xcel also loses the ability to earn revenue by selling the unit’s energy into the MISO market.⁵⁶

The increased costs and lost revenues that Xcel experiences as a result of a generator outage are referred to as “replacement-power costs.”⁵⁷ In this case, Xcel estimates the total replacement-power costs incurred during the October 2023 outage to be approximately \$48.5 million on a Total Company basis, or \$34.3 million for the Minnesota Jurisdiction.⁵⁸

Xcel collects fuel and purchased-energy costs through an automatic-rate-adjustment mechanism called the Fuel Clause Rider.⁵⁹ The Fuel Clause Rider undergoes an annual “true-up” process where the total energy costs Xcel incurs in a year are compared to what was collected through the rider.⁶⁰ Xcel then recalculates the Fuel Clause rates to refund any overcollection to ratepayers or surcharge ratepayers for any undercollection.⁶¹

⁵⁴ Ex. DOC-1 at 3 (Golden Direct).

⁵⁵ Ex. DOC-1 at 3 (Golden Direct).

⁵⁶ Ex. DOC-1 at 4 (Golden Direct).

⁵⁷ *See, e.g.*, Ex. Xcel-5 at 14 (Detmer Direct) (referring to these costs alternately as “replacement power costs” and “incremental power-related costs”).

⁵⁸ Ex. DOC-1 at 4 (Golden Direct).

⁵⁹ *See* N. States Power Co., Minnesota Electric Rate Book at 91, 91.2 (Apr. 30, 2021), https://www.xcelenergy.com/company/rates_and_regulations/rates/rate_books (click “[Section 5 - Rate Schedules Part 3 \(PDF\)](#)” link).

⁶⁰ Ex. Xcel-2 at 7 (Krug Direct).

⁶¹ *See* Ex. Xcel-2 at 7 (Krug Direct) (describing true-up process).

Xcel recovered replacement-power costs for Prairie Island from ratepayers through the Fuel Clause Rider,⁶² and did not propose any refund in its March 2024 true-up filing.⁶³ Indeed, few details of the October 2023 incident appeared in Xcel’s filing at all.⁶⁴ As a result, it fell to the Department of Commerce, the OAG, and the Citizens Utility Board to uncover the root causes of the outage and draw the Commission’s attention to Xcel’s imprudence and the need for a refund.⁶⁵

V. THE COMMISSION FINDS THAT XCEL IMPRUDENTLY CAUSED THE OUTAGE AND REFERS THE CASE TO THE COURT OF ADMINISTRATIVE HEARINGS TO DEVELOP THE RECORD ON REPLACEMENT-POWER COSTS.

The Commission concluded that the October 2023 incident and outage resulted from Xcel’s imprudence and that Xcel should not be allowed to retain the imprudently incurred replacement-power costs.⁶⁶ The Commission was unable, however, to determine from the existing record the refund amount necessary to remedy Xcel’s imprudence.⁶⁷ It therefore referred the matter to the Court of Administrative Hearings (CAH) for a contested case to determine the appropriate refund amount.⁶⁸ At Xcel’s request, the Commission also directed that the contested case 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.”⁶⁹

⁶² See ORDER APPROVING 2023 FUEL-CLAUSE TRUE-UP REPORT, REQUIRING ADDITIONAL FILINGS, FINDING IMPRUDENCE, AND NOTICE OF AND ORDER FOR HEARING at 3 (Nov. 15, 2025) (finding that ratepayers “have borne the resulting costs” of the October 2023 outage through the fuel clause) [hereinafter REFERRAL ORDER].

⁶³ See *generally* Annual True-up and Compliance Report (Mar. 1, 2024).

⁶⁴ See Annual True-up and Compliance Report at 10, part C attachs. 4, 5 (Mar. 1, 2024).

⁶⁵ See REFERRAL ORDER at 3–4.

⁶⁶ REFERRAL ORDER at 2.

⁶⁷ REFERRAL ORDER at 8.

⁶⁸ REFERRAL ORDER at 8–9, 11.

⁶⁹ ORDER DENYING PETITION FOR RECONSIDERATION AND GRANTING REQUEST FOR CLARIFICATION at 4 (Jan. 31, 2025).

LEGAL STANDARD

Every rate “made, demanded, or received” by a public utility must be just and reasonable.⁷⁰

The burden to prove that a rate is just and reasonable is on the utility, and any doubt as to reasonableness will be resolved in favor of the consumer.⁷¹ As the party with the burden of proof, Xcel “ha[s] the burden of supporting its proposed action by a preponderance of the evidence.”⁷²

Automatic adjustments through the Fuel Clause Rider are considered provisionally approved and are placed into effect without Commission action.⁷³ Erroneous adjustments are subject to refund.⁷⁴ Moreover, the Commission may after investigation, notice, and hearing issue an order to discontinue or modify an automatic adjustment.⁷⁵ “When a utility proposes new or revised electric energy . . . adjustment provisions, the proposal is considered a change in rates and must be reviewed according to commission rules and practices relating to utility rate changes.”⁷⁶ Accordingly, the burden of proof does not shift to intervenors by virtue of the fact that Xcel has already recovered the replacement-power costs. Rather, the burden remains on Xcel to establish the amount of fuel and purchased energy costs it is entitled to recover through the Fuel Clause Rider by a preponderance of the evidence.⁷⁷

Xcel also has the burden to establish its claimed offsets by a preponderance of the evidence.⁷⁸ When a utility seeks to offset a refund of replacement-power costs using benefits that allegedly arose from a forced outage, such as avoiding future outages, the utility’s burden of proof

⁷⁰ Minn. Stat. § 216B.03.

⁷¹ *See id.*; Minn. Stat. § 216B.16, subd. 4.

⁷² Minn. R. 1400.8608.

⁷³ Minn. R. 7825.2920, subp. 1.

⁷⁴ Minn. R. 7825.2920, subp. 2.

⁷⁵ Minn. R. 7825.2920, subp. 3.

⁷⁶ Minn. R. 7825.2390.

⁷⁷ *See* Minn. Stat. § 216B.16, subd. 4; Minn. R. 1400.8608.

⁷⁸ *See* Minn. R. 1400.8608 (providing that if a party “asserts any affirmative defenses, that party shall have the burden of proving the defense by a preponderance of the evidence”).

requires it to do more than offer speculative estimates of future costs that were avoided.⁷⁹ Moreover, the Commission historically has not allowed a utility to offset a refund of imprudently incurred replacement-power costs using benefits that accrued from the utility’s prudent actions “responding to and resolving the consequences of” the prior imprudent conduct.⁸⁰ This is because a utility’s “prudent management of the restoration process—including efforts to mitigate costs—[is] the expectation and does not offset or mitigate . . . prior imprudence.”⁸¹

ARGUMENT

Xcel’s litigation strategy in this case elevates burden-shifting to an art form. At every turn, Xcel asks the ALJ and the Commission to accept unproven assumptions, resolving doubt in its favor, when the law requires exactly the reverse—resolving all doubt in favor of consumers. Xcel’s goal is to avoid responsibility for its actions and deprive ratepayers of more than \$28 million that they are owed because of its imprudence.

First, Xcel asks the ALJ and the Commission to accept unsupported assumptions regarding the October 2023 outage’s impact on its other generators. These assumptions make the outage look less costly to ratepayers than it was, decreasing their refund. Xcel’s energy-cost modeling should be rejected, and replacement-power costs should be calculated using a simpler method that asks what Prairie Island’s net revenues would have been had it been online during the outage.

Second, Xcel trots out three “offsets” that it contends should reduce the total replacement-power costs refunded to ratepayers. The first two offsets imply that the October 2023 outage *benefitted* ratepayers by avoiding future outages, but reaching this conclusion would require the

⁷⁹ See *In re Application of N. States Power Co.*, MPUC Docket Nos. E-002/GR-12-961 et al., ORDER ADOPTING ADMINISTRATIVE LAW JUDGE REPORT AS MODIFIED, REQUIRING REFUND OF CERTAIN DISALLOWED REPLACEMENT POWER COSTS, AND REQUIRING FURTHER ACTION at 36 (Dec. 24, 2024) [hereinafter SHERCO 3 ORDER].

⁸⁰ SHERCO 3 ORDER at 36.

⁸¹ SHERCO 3 ORDER at 36.

ALJ and the Commission to resolve a series of uncertain assumptions in favor of Xcel rather than consumers. The third offset goes beyond burden-shifting: Xcel contends that because Prairie Island was on a hot streak in 2018–2022 (a period Xcel cherry picks where the plant had relatively few outages), the Commission should slash ratepayers’ refund in half. This “performance adjustment” must be soundly rejected: Xcel is expected to operate its plants prudently and cannot bank extra prudence to avoid making ratepayers whole from its imprudence.

Finally, the Commission should require that Xcel bear its own costs for this contested case, which has been primarily a vehicle for Xcel to try to deprive ratepayers of a refund to which they are entitled because of Xcel’s costly mistake in October 2023.

I. THE COMMISSION SHOULD REQUIRE XCEL TO REFUND \$40.6 MILLION IN REPLACEMENT-POWER COSTS.

Xcel used a software program called PLEXOS to estimate the replacement-power cost that resulted from the October 2023 outage.⁸² Xcel first modeled a “base case” scenario reflecting data on the actual operation of its system without Prairie Island.⁸³ Once the base case was calibrated to actual operations, Xcel extracted the total system costs from the model for the outage, or the “study period.”⁸⁴ Xcel then created a “change case” that made Prairie Island available for generation during the same period.⁸⁵ The difference in cost between Xcel’s base and change cases was \$34.3 million allocated to Minnesota.⁸⁶

XLI witness Brian Andrews and Department witness Steve Rakow identified significant flaws and inconsistencies in Xcel’s modeling assumptions.⁸⁷ These flaws led them to conclude

⁸² See Ex. Xcel-5 at 13, 16 (Detmer Direct).

⁸³ Ex. Xcel-5 at 16 (Detmer Direct).

⁸⁴ Ex. Xcel-5 at 16 (Detmer Direct).

⁸⁵ Ex. Xcel-5 at 16 (Detmer Direct).

⁸⁶ Ex. Xcel-5 at 16 (Detmer Direct).

⁸⁷ See Ex. XLI-1 at 5–11 (Andrews Direct); Ex. XLI-3 at 3–7 (Andrews Surrebuttal); Ex. DOC-3 at 5–14 (Rakow Surrebuttal).

that a more reliable method of estimating the replacement-power costs in this case would be the “LMP method” calculation described by Mr. Andrews.⁸⁸

The LMP method assumes that the output of Xcel’s other generators would have been largely unchanged regardless of Prairie Island’s availability.⁸⁹ The replacement-power costs can then be determined by calculating the net revenue that Xcel would have earned from Prairie Island had it been operating as usual during the October 2023 outage.⁹⁰ Under the LMP method, the net revenue Xcel would have earned from Prairie Island is assumed to equal the product of its generation (in MWh) and the prevailing the market prices (or LMPs), less Prairie Island’s fuel and operating costs.⁹¹ Using the LMP method, Mr. Andrews calculated a replacement-power cost for the October 2023 outage of \$40.6 million (MN jurisdiction), a substantial increase from the \$34.3 million (MN jurisdiction) Xcel had calculated using PLEXOS.⁹²

Xcel acknowledges that the LMP method is a common method for estimating replacement-power costs and that Xcel used the method to calculate an initial estimate in this case.⁹³ However, Xcel argues that the LMP method is appropriate only where the size of a facility is small, such that a change in its availability does not impact the output of other nearby resources.⁹⁴ Xcel contends that Prairie Island is a large resource relative to the MISO North region and that the availability of

⁸⁸ Ex. XLI-1 at 15 (Andrews Direct); Ex. XLI-5 at 1 (Andrews Direct Errata); Ex. XLI-3 at 8 (Andrews Surrebuttal); Ex. DOC-3 at 19 (Rakow Surrebuttal).

⁸⁹ Ex. DOC-3 at 14–15 (Rakow Surrebuttal).

⁹⁰ Ex. DOC-3 at 15 (Rakow Surrebuttal).

⁹¹ Ex. XLI-1 at 8 (Andrews Direct).

⁹² Ex. XLI-2 at 12 (Andrews Trade Secret Direct). While Mr. Andrews marks the total dollar amount as trade secret, Xcel indicated, via an email dated November 18, 2025, that it would waive trade-secret protection for XLI’s total.

⁹³ Ex. Xcel-5 at 9 (Detmer Rebuttal).

⁹⁴ Ex. Xcel-5 at 9 (Detmer Rebuttal).

Prairie Island “would impact” the output of other Xcel generation resources.⁹⁵ Xcel asserts that a production-cost model like PLEXOS is needed to evaluate this impact.⁹⁶

While production-cost modeling would normally be the preferred way of estimating replacement-power costs, Xcel’s modeling here is too unreliable to use.⁹⁷ Most fatally, Xcel’s modeling assumes transmission-system constraints that are unsupported by real-world data.⁹⁸ Xcel asserts that because of transmission constraints between the MISO North region and the rest of MISO, the output of its other generators would have been materially impacted by Prairie Island’s unavailability.⁹⁹ But Xcel has failed to show that its other generators were materially impacted, and actual market-pricing data do not support the existence of significant congestion.¹⁰⁰ Given the lack of reliable modeling, the LMP method provides a reasonable estimate for the purposes of refunding replacement-power costs.¹⁰¹

Recent experience in another Xcel forced-outage case suggests that, if anything, the LMP method may *understate* the October 2023 outage’s costs.¹⁰² Xcel incurred replacement-power costs following a catastrophic failure of Unit 3 at its Sherburne County (Sherco) Generating Station.¹⁰³ Xcel’s modeling in that case accounted for three categories of costs and revenues: (1) lost net revenue from Unit 3; (2) increased expense of making more purchases from the market; and (3) increased net revenue from other Xcel generators.¹⁰⁴ The increased expense from market

⁹⁵ Ex. Xcel-5 at 10 (Detmer Rebuttal).

⁹⁶ Ex. Xcel-5 at 10 (Detmer Rebuttal).

⁹⁷ Ex. DOC-3 at 14, 19 (Rakow Surrebuttal).

⁹⁸ Ex. DOC-3 at 14, 19 (Rakow Surrebuttal).

⁹⁹ Ex. DOC-3 at 7 (Rakow Surrebuttal).

¹⁰⁰ Ex. DOC-3 at 13 (Rakow Surrebuttal).

¹⁰¹ Ex. DOC-3 at 19 (Rakow Surrebuttal).

¹⁰² See Ex. XLI-1 at 14 (Andrews Direct).

¹⁰³ SHERCO 3 ORDER at 2.

¹⁰⁴ Ex. XLI-1 at 14 (Andrews Direct).

purchases and the increased net revenue from other Xcel generators largely canceled each other out, leaving lost net revenue from Sherco Unit 3 as the bulk of the replacement-power costs.¹⁰⁵ The lost net revenue in Sherco is the equivalent of XLI's LMP-method calculation here.¹⁰⁶ And in Sherco, the increased market-purchase expenses exceeded the increased net revenue from other generators by more than five percent, meaning that the net impact of these two cost categories was to increase the refund.¹⁰⁷ In other words, looking at lost net revenues in isolation, as the LMP method does, may actually understate total replacement-power costs.¹⁰⁸

For these reasons, Xcel has failed to meet its burden to establish by a preponderance of the evidence that the Prairie Island replacement-power costs were \$34.3 million (MN jurisdiction). Instead, the best available estimate of replacement-power costs stemming from the outage is the amount calculated using the LMP method. For the reasons explained in the next section, Xcel has failed to establish that any of its proposed offsets should be applied to reduce the replacement-power costs refund. Therefore, the ALJ should recommend, and the Commission should order, that Xcel refund \$40.6 million (MN jurisdiction) through the Fuel Clause Rider.

II. THE COMMISSION SHOULD REJECT XCEL'S PROPOSED OFFSETS.

Xcel has advanced three offsets that, together, would reduce the replacement-power-cost refund by \$28.5 million, or more than 80 percent of Xcel's proposed replacement-power costs. These offsets are (1) the "supplemental work" offset; (2) the "2029 avoided costs offset; and (3) a "historic performance adjustment":

¹⁰⁵ See Ex. XLI-1 at 14 (Andrews Direct).

¹⁰⁶ Ex. XLI-1 at 14 (Andrews Direct).

¹⁰⁷ See Ex. XLI-1 at 14 (Andrews Direct).

¹⁰⁸ Ex. XLI-1 at 14 (Andrews Direct).

**Table 1 –
Xcel’s Proposed Customer Refund After Offsets¹⁰⁹**

Replacement-Power Costs per Xcel	\$34.3 million
Less Supplemental Work Offset	\$1.8 million*
Less Avoided 2029 Costs Offset	<u>\$21.0 million</u>
Subtotal	\$11.4 million
Historic Performance Adjustment	<u>51%</u>
Total Customer Refund	\$5.8 million

* In rebuttal testimony, Xcel revised the supplement-work offset to \$500,000.

For the reasons discussed in the following sections, the ALJ and the Commission should reject Xcel’s offsets in their entirety.

The supplemental-work and “avoided 2029 costs” offsets are both premised on the theory that the work Xcel completed during the October 2023 outage avoided future outages. But they both rely on unproven assumptions, and the “avoided 2029 costs” offset is inconsistent with Commission precedent denying offsets for a utility’s efforts to remedy prior imprudence. Moreover, Xcel inflates both offsets by allocating a larger percentage share of the offset to Minnesota than the percentage it uses to allocate replacement-power costs to Minnesota. This difference in allocators is premised on projections of sales changes among Xcel’s three jurisdictions (Minnesota and the Dakotas) due to data-center growth in the late 2020s and thus resolves significant uncertainty about the future in Xcel’s favor.

Last, Xcel requests a “historic performance adjustment,” which according to Xcel recognizes the exemplary performance of Prairie Island in 2018–2022. The Commission, however, has found that Xcel has a duty to operate and maintain its generation plants in a

¹⁰⁹ Ex. Xcel-7 at 24 tbl.4 (Detmer Public Direct Errata). All amounts are Minnesota-jurisdictional.

reasonable and prudent manner.¹¹⁰ Utilities do not get “extra credit” for prudently operating power plants, and the historic performance adjustment is an unprecedented attempt to evade responsibility for the consequences of Xcel’s imprudent actions in October 2023.

A. The Commission Should Reject Xcel’s “Supplemental Work” Offset.

Xcel seeks an offset of \$500,000 for supplemental work, unrelated to the control-cable replacement, that it completed during the October 2023 outage.¹¹¹ Xcel initially sought credit for 8,505 labor hours of supplemental work, claiming that doing this work during the outage avoided 8.1 future outage days and associated replacement-power costs worth \$1.8 million (MN jurisdiction).¹¹² In rebuttal testimony, however, Xcel conceded that completing this supplemental work avoided no more than 2.2 future outage days, or approximately \$500,000 (MN jurisdiction) in replacement-power costs.¹¹³ Even this reduced offset amount is unreasonable. The Commission should deny any offset for the supplemental work because Xcel has failed to establish that doing this work during the October 2023 outage avoided or shortened a future outage.¹¹⁴

Xcel asserts that two of the supplemental projects—replacing a pipe in the cooling water system and inspecting the “plant screenhouse stop rail guide”—needed to be done with both units offline.¹¹⁵ Xcel reasons that if these dual-unit projects were done during a scheduled refueling outage of one of the units, they would cause an outage of the nonrefueling unit.¹¹⁶ Xcel concludes that doing these projects when Prairie Island was already in a dual-unit outage “avoided the non-

¹¹⁰ SHERCO 3 ORDER at 16.

¹¹¹ Ex. OAG-4 at 7 (Lee Surrebuttal).

¹¹² Ex. OAG-1 at 6–7 (Lee Direct).

¹¹³ Ex. Xcel-3 at 6 (Krug Rebuttal).

¹¹⁴ See Ex. OAG-4 at 3 (Lee Surrebuttal).

¹¹⁵ See Ex. Xcel-12 at 7–8 (Bible Rebuttal).

¹¹⁶ Ex. Xcel-12 at 8 (Bible Rebuttal).

refueling operating unit shutdown outage days” in a future refueling outage.¹¹⁷ Xcel’s conclusion, however, depends on two unproven assumptions.

First, Xcel assumes that the need to complete these projects would have caused Xcel to convert a single-unit refueling outage into a dual-unit outage. Under Xcel’s chosen scenario of a single-unit refueling outage, completing a project that required *both* units to be offline would indeed drive outage time for the non-refueling unit (assuming there were no other reason to take the non-refueling unit offline). But Xcel’s theory that the supplemental-work projects would, on their own, have occasioned a dual-unit outage is contradicted by the record.

Before the October 2023 outage, the cooling-water-system pipe replacement project was on Xcel’s “dual unit forced outage list.”¹¹⁸ This means that the pipe-replacement project was not scheduled to occur during a planned refueling outage but rather “was identified as needing to be added to the next available dual unit outage.”¹¹⁹ In other words, Xcel has the causation backwards: the decision to do the pipe-replacement project was driven by a dual-unit forced outage and not vice versa. With regard to the plant screenhouse stop rail guide inspection, the initial data that Xcel presented suggested that this project did not require an outage *at all*, much less a dual-unit outage.¹²⁰ But even assuming that the inspection could only be done during a dual-unit outage, there is no evidence that the need to complete this project, alone, would have caused Xcel to schedule a dual-unit outage.

Xcel’s second unsupported assumption is that these projects would have driven the *length* of a future dual-unit outage. In other words, Xcel assumes that these projects would have been

¹¹⁷ Ex. Xcel-12 at 8 (Bible Rebuttal).

¹¹⁸ Ex. OAG-4 at 4 (Lee Surrebuttal).

¹¹⁹ Ex. OAG-4 at 4 (Lee Surrebuttal).

¹²⁰ Ex. OAG-4 at 5 (Lee Surrebuttal).

“critical path” in any future outage. A “critical path” project is simply the project that takes the longest and therefore drives an outage’s length.¹²¹ Xcel admits that “whether an item is critical path can depend on the other projects scheduled for the same outage” and that “[i]f a future dual unit outage were performed and included other work that was scheduled to take more time to perform than these two activities, then these activities would not be critical path.”¹²² It is unknown whether the supplemental work could or would have been done in parallel with a longer-duration project in a future outage and, therefore, whether completing them during the October 2023 outage avoided any future outage days.¹²³

The supplemental work did not drive the length of the October 2023 outage,¹²⁴ and Xcel has given no reason, beyond conclusory assertions, to believe that these relatively small projects would drive the length of any other outage. Accordingly, Xcel has failed to carry its burden to prove that pulling forward these projects saved any future outage time, and the ALJ and the Commission should reject Xcel’s request for an offset on that basis.

B. The Commission Should Reject Xcel’s “Avoided 2029 Costs” Offset.

Xcel seeks an offset of \$21.0 million (MN jurisdiction) because it claims that replacing the control cables during the October 2023 outage eliminated the need to do so later, avoiding replacement-power costs associated with a hypothetical 2029 cable-replacement outage.¹²⁵ The ALJ and the Commission should reject this offset for two main reasons. First, the Commission rejected this type of offset on principle when Xcel raised a similar defense after the catastrophic failure at Xcel’s Sherco plant. Second, even if this type of offset were permissible, it depends

¹²¹ Ex. OAG-4 at 3 (Lee Surrebuttal).

¹²² Ex. OAG-4 at 3 (Lee Surrebuttal).

¹²³ Ex. OAG-4 at 3 (Lee Surrebuttal).

¹²⁴ Ex. OAG-4 at 3 (Lee Surrebuttal).

¹²⁵ Ex. OAG-1 at 12 (Lee Direct).

upon too many uncertain assumptions to justify using it to reduce the ratepayer refund for the October 2023 outage.

1. Xcel may not offset a customer refund based on Xcel’s efforts to remedy its own imprudence.

Xcel’s “avoided 2029 costs” offset seeks credit for avoiding a future outage to replace the control cables. Xcel, in other words, is attempting to offset a customer refund for its imprudent conduct using an alleged benefit that may eventually result from Xcel’s efforts to remedy that imprudence. The Commission rejected exactly this type of offset last year in a forced-outage case where it ordered a refund for Xcel’s imprudent maintenance of Sherco Unit 3. It should do the same here.

Sherco Unit 3 experienced an extended outage caused by Xcel’s imprudence.¹²⁶ Similar to this case, Xcel purchased replacement power to during the outage and recovered the costs of the replacement power from ratepayers via the Fuel Clause Rider.¹²⁷ As here, Xcel advanced several offsets to avoid paying a full refund,¹²⁸ including one for avoided future outage time.¹²⁹

Xcel made essentially the same arguments there as it is making here. Xcel witness Darin Schottler testified that the restoration of Sherco Unit 3 avoided approximately 10 to 11 weeks of outage time to conduct planned overhauls of this equipment in the future.¹³⁰ Xcel witness Nicholas Detmer (who is also a witness in the current case) agreed that the work performed during the Sherco Unit 3 outage enabled Xcel to “avoid or shorten later planned outages, meaning the

¹²⁶ SHERCO 3 ORDER at 4.

¹²⁷ SHERCO 3 ORDER at 2.

¹²⁸ SHERCO 3 ORDER at 27.

¹²⁹ See SHERCO 3 ORDER at 32–33; see also MPUC Docket No. E-002/GR-12-961, ALJ FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS at 81–82 (May 17, 2024) (noting Xcel’s claim that ratepayers benefitted from the outage due, in part, to the reduction of future outage time).

¹³⁰ MPUC Docket No. E00-2/GR-12-961, Direct Test. of Darin W. Schottler at 15 (June 16, 2023).

Company also avoided replacement power costs that otherwise would have been passed on to customers.”¹³¹ Mr. Detmer estimated that Xcel avoided “a total of 76 to 84 days of additional outage time after Unit 3 returned to service, with those avoided outage days occurring . . . between [the] 2015 and 2022 time frame” and further estimated the value of the associated replacement power to be approximately \$4.3 million to \$4.8 million (MN jurisdiction).¹³²

The Commission determined that it would not allow Xcel “to offset a refund of imprudently incurred costs by any benefits that accrued from Xcel’s prudent actions responding to and resolving the consequences of Xcel’s imprudent behavior.”¹³³ In other words, prudently managing the restoration process, including mitigating future costs, was “the expectation and does not offset or mitigate Xcel’s prior imprudence.”¹³⁴

The Commission should deny Xcel’s “avoided 2029 costs” offset for the same reasons it denied Xcel’s avoided-replacement-power offset in the Sherco case. As in that case, here Xcel is trying to get credit for future replacement-power costs it claims to have avoided by responding to and resolving the consequences of failing to prudently oversee the excavations. But, just as in Sherco, prudently responding to the October 2023 incident was the expectation and should not offset or mitigate its prior imprudence.

2. The “avoided 2029 costs” offset depends on numerous speculative assumptions.

Even if the ALJ and Commission believe Xcel should be able to use efforts to correct its imprudence as the basis for an offset, the ALJ and Commission should still reject the “avoided

¹³¹ MPUC Docket No. E00-2/GR-12-961, Direct Test. of Nicholas J. Detmer at 19 (June 16, 2023).

¹³² MPUC Docket No. E00-2/GR-12-961, Direct Test. of Nicholas J. Detmer at 19 (June 16, 2023).

¹³³ SHERCO 3 ORDER at 36.

¹³⁴ SHERCO 3 ORDER at 36.

2029 costs” offset because it depends on many unproven assumptions. In Sherco, the Commission found Xcel’s estimates “too speculative and unsupported to justify the offsets sought by Xcel.”¹³⁵

Likewise, here, the avoided 2029 costs offset depends on numerous assumptions for which Xcel has offered limited or no proof: (1) that, absent the October 2023 incident, the control cables would have been replaced during subsequent licensing renewal (SLR); (2) that the cables inevitably would have failed had they not been replaced during the SLR process; (3) that a future cable replacement would not be the result of Xcel’s imprudence; and (4) that the cable-replacement project would have been critical-path in a future outage. If any one of these predictions does not come true, the avoided “2029 costs offset” collapses. Because Xcel has failed to substantiate any of these claims, the ALJ and the Commission should find that the “avoided 2029 costs” offset is unsupported.

a. The “avoided 2029 costs” offset is based on an event that Xcel’s own witness testified has a less-than-20-percent chance of occurring.

Xcel’s avoided 2029 costs offset is based on a scenario it calls “Case 1.”¹³⁶ Case 1 assumes that, absent the October 2023 incident, Xcel would have inspected the control cables as part of the SLR process, discovered their degraded condition, and replaced them in 2029.¹³⁷ However, the engineer that Xcel engaged to evaluate the SLR process determined that there was “less than a 20 percent probability” that the control cables would have been selected for inspection in the SLR process.¹³⁸ In other words, Xcel’s avoided 2029 costs offset is based on a scenario that had only a one-in-five chance of occurring.

¹³⁵ SHERCO 3 ORDER at 36.

¹³⁶ Ex. Xcel-2 at 14 (Krug Direct).

¹³⁷ Ex. Xcel-5 at 18 (Detmer Direct).

¹³⁸ Ex. Xcel-13, sched. 2 at 13 (Hiser Direct).

Xcel characterizes its use of Case 1 as “conservative” because the two other scenarios that Xcel modeled (“Case 2” and “Case 3”) would have yielded even larger avoided costs.¹³⁹ But this ignores that there are any number of other scenarios that Xcel did *not* model or otherwise consider.¹⁴⁰ Some of these scenarios would have yielded fewer avoided costs than Xcel’s Case 1 scenario. Indeed, some of these scenarios could even result in *no* recoverable costs if the future outage in which the cables are replaced is caused by Xcel’s imprudence.¹⁴¹ For the reasons discussed in the next section, Xcel’s Case 2 and Case 3 scenarios are also too uncertain to use as the basis for an offset.

b. Xcel assumes that, if the control cables were not inspected and replaced because of SLR, they would have inevitably failed due to degradation, and this failure would have occurred in 2029.

Xcel’s Case 2 and 3 scenarios assume that the control cables would spontaneously fail when either (a) both units are online (Case 2) or (b) one unit is in scheduled refueling (Case 3).¹⁴² To quantify the avoided replacement-power costs for these hypothetical failures, Xcel assumed an outage in 2029 (when Unit 2 is already scheduled to be refueled) and used modeling software to evaluate the avoided power costs at that time.¹⁴³ The problem with this approach is twofold. First, Cases 2 and 3 both assume that the control cables would inevitably have failed during the life of the plant—an outcome that is simply unknowable. And second, they both assume that this spontaneous failure would have occurred in 2029, an even more speculative prediction.

¹³⁹ See Ex. Xcel-5 at 18 (Detmer Direct).

¹⁴⁰ Ex. OAG-1 at 15 (Lee Direct).

¹⁴¹ See *infra* Part II.B.2.c (explaining how Xcel failed to rule out that the 2029 cable replacement outage would be the result of imprudence).

¹⁴² Ex. Xcel-5 at 18–19 (Detmer Direct).

¹⁴³ Ex. Xcel-5, sched. 2 at 3 (Detmer Public Direct).

Xcel’s basis for arguing that the cables would have eventually failed is the condition in which they were found after Xcel severed them.¹⁴⁴ The cables were direct-buried, parts of the outer jacketing were cracked, and there was evidence that the cables had been exposed to moisture.¹⁴⁵ But there is simply no way of knowing whether they would have failed absent the October 2023 incident. The cables had been in service for 50 years without issue before the October 2023 incident,¹⁴⁶ and Xcel’s previous testing of equipment served by the cables had indicated that all conductors were working normally.¹⁴⁷ Moreover, industry experience is that control cables fail either due to damage caused during installation or from long-term exposure to water.¹⁴⁸ Since there had been “no observations of water accumulation in manholes or ponding of water in the vicinity of these cables,”¹⁴⁹ it is likely that any water intrusion into the cables would be a gradual process. There is no evidence that the degradation would have continued at a rate that would have led to the cables’ failure during Prairie Island’s operating life.¹⁵⁰ And, even if Xcel had established this, it would still have to prove that it was not at fault for the cables’ accelerated degradation as discussed in the next section.

Moreover, even if Xcel had shown that the control cables would fail during the plant’s operating life, Xcel cannot reasonably predict *when* the cables would have failed or how much this failure would have cost. Xcel acknowledges that the timing of the avoided cable-replacement outage is merely an estimate.¹⁵¹ Moreover, replacement-power costs can vary significantly on a

¹⁴⁴ Ex. Xcel-10, sched. 2 at 3 (Bible Direct).

¹⁴⁵ Ex. OAG-5 at 11, 14 of 16 (EPRI Report – Final).

¹⁴⁶ Ex. Xcel-12 at 4 (Bible Rebuttal).

¹⁴⁷ Ex. Xcel-14, sched. 1 at 3, attach. A (Hiser Rebuttal).

¹⁴⁸ Ex. Xcel-10, sched. 2 at 4 (Bible Direct).

¹⁴⁹ Ex. Xcel-10, sched. 2 at 4 (Bible Direct).

¹⁵⁰ *But see* Ex. Xcel-10 at 2 (Bible Direct) (claiming “high probability” that cables would have failed if not discovered during boring activity).

¹⁵¹ Ex. Xcel-5 at 17 (Detmer Direct).

day-to-day basis.¹⁵² In other words, Xcel’s avoided-costs estimate required it to guess when the cables would fail and then guess what wholesale power costs would be at that time. Xcel had to make *dozens* of assumptions to forecast costs out to 2029—hourly LMPs, hourly loads, monthly fuel prices, monthly operation and maintenance costs for every generator, unit heat rates, outage rates, startup costs, and fuel-transportation costs, just for starters.¹⁵³ The upshot is that Xcel is asking the Commission to offset the very real replacement-power costs that ratepayers experienced during the October 2023 outage with highly uncertain avoided replacement-power costs from a hypothetical outage four years in the future. This would not resolve doubt in favor of ratepayers or yield a just and reasonable refund.

The avoided costs Xcel calculates in this case are even more uncertain than the avoided costs for the offset that the Commission rejected in the Sherco case. The projects that Xcel avoided by repairing Sherco Unit 3 involved scheduled maintenance that the Company was already planning to do. Xcel even identified rough timeframes for when it would otherwise have completed this maintenance—between 2015 and 2022.¹⁵⁴ In this case, however, we have no idea if or when the control cables would have failed or been replaced, since they had worked without issue through 50 years of service and Xcel had no plans to replace them.

c. Xcel assumes that a future control-cable replacement would not be caused, in whole or part, by Xcel’s own imprudence.

Even if it were possible to know that the control cables would have been replaced in 2029, for the avoided costs of that future replacement to offset the refund in this case, Xcel would have to establish that the future replacement would not have been caused by its imprudence. Xcel has failed to do so, and in fact the available evidence suggests the contrary.

¹⁵² Ex. Xcel-5 at 17 (Detmer Direct).

¹⁵³ Ex. XLI-3 at 9 (Andrews Surrebuttal).

¹⁵⁴ MPUC Docket No. E00-2/GR-12-961, Direct Test. of Nicholas J. Detmer at 20 (June 16, 2023).

First, there is no way to rule out the possibility that Xcel would have imprudently damaged the control cables at some future time had it not done so in 2023.¹⁵⁵ We know that this is a possibility because it has happened before—namely, in October 2023. The root causes of the October 2023 incident were weakness in Xcel’s excavation-permit approval process and inadequate oversight of the non-nuclear supplemental workers.¹⁵⁶ After the October 2023 incident, Xcel implemented multiple procedure changes to address these oversight and permit-approval gaps.¹⁵⁷ However, had the incident not occurred, Xcel may not have made these procedural changes, leaving a meaningful possibility that a similar incident could occur in the future.¹⁵⁸

In addition to Xcel imprudently damaging the control cables at a later time, it is also possible that the cables could fail or need replacing due to Xcel’s imprudent installation or maintenance. And, as discussed earlier, EPRI’s report suggests that Xcel’s sub-par installation contributed to the cables’ degradation. The control-cable bundle was direct buried in the ground, which was consistent with industry practice in the early 1970s.¹⁵⁹ However, when burying electric cables, it is important to use the right type of fill material—composed of a range of particle sizes—to decrease thermal resistance and control moisture levels.¹⁶⁰ According to EPRI’s report, Xcel’s control cables were buried in soil composed largely of fine sand of similar particle size with low

¹⁵⁵ See Evid. Hrg. Tr. at 38 (Krug) (agreeing that Xcel could have cut through the control cables at a future time had it not done so in 2023).

¹⁵⁶ Ex. OAG-7 at 7 of 14.

¹⁵⁷ Ex. OAG-7 at 7 of 14.

¹⁵⁸ Evid. Hrg. Tr. at 42 (Krug).

¹⁵⁹ Ex. Xcel-10, sched. 2 at 3 (Bible Direct).

¹⁶⁰ Ex. OAG-5 at 11 of 16 (EPRI Report – Final).

moisture content, suggesting that its thermal resistivity was “higher than planned for buried cables.”¹⁶¹

Unfortunately, since Xcel provided the soil sample in an unsealed container contrary to EPRI’s instructions, EPRI was not able to derive meaningful thermal resistance information from it.¹⁶² However, the evidence that portions of the cable had overheated suggests that the manner in which Xcel installed the cables contributed to their degradation.¹⁶³ The conclusion that Xcel may have improperly installed the cables is also supported by the testimony of Xcel witness Allen Hiser. Mr. Hiser testified that it is possible for direct-buried cables to last essentially indefinitely in the ground, and that he was unaware of DC control cables at any other plant experiencing this level of degradation.¹⁶⁴

Xcel has failed to show that the control cable’s future failure would not have been caused by its own imprudence. And Xcel is not entitled to offset the refund owed to ratepayers for October 2023-outage replacement-power costs with hypothetical outage costs necessary to address a cable failure that it may have imprudently caused.

d. Xcel assumes that the cable replacement would have been critical path in a future outage.

Finally, Xcel’s offset relies on the assumption that the cable replacement would have been the critical-path project in the 2029 outage.¹⁶⁵ This distinction is important because if a project is not critical-path, it does not drive the outage’s overall length and thereby replacement-power costs.¹⁶⁶ In other words, if the 2029 cable replacement were done concurrently with other work

¹⁶¹ Ex. OAG-5 at 10–11 of 16.

¹⁶² Ex. OAG-5 at 10 of 16.

¹⁶³ See Ex. OAG-5 at 14 of 16 (discussing evidence that cables had been subject to overheating and explaining how improper fill material can contribute to overheating).

¹⁶⁴ Evid. Hrg. Tr. at 95 (Hiser).

¹⁶⁵ Ex. OAG-4 at 10 (Lee Surrebuttal).

¹⁶⁶ Ex. OAG-4 at 10 (Lee Surrebuttal).

that required as much or more time to complete, then replacing the cable during the October 2023 outage did not avoid any future outage time or replacement-power costs.¹⁶⁷ In any outage, Xcel is expected to minimize costs,¹⁶⁸ as it did by adding supplemental work to the October 2023 outage. In its 2029 scenario, however, contrary to the principle of cost-minimization, Xcel assumes that the cable replacement would not be scheduled to overlap with other major work. This assumption favors Xcel and unjustly decreases ratepayers' refund.

While Xcel does assume it would have taken some steps to minimize the 2029 outage length—specifically, trenching and laying cable prior to shutting the units down—Xcel also assumes that the only other work done during the outage would be refueling one of the two units.¹⁶⁹ Xcel assumes this refueling work is “planned for approximately 27 days without major work scope other than the cable replacement project.”¹⁷⁰ Yet most of Xcel’s planned outages since 2005 have been longer than 27 days and in some cases, substantially longer.¹⁷¹ According to information provided by Xcel, Prairie Island has had six planned outages exceeding 70 outage days since January 2005, and many others exceeding 30 outage days.¹⁷²

Xcel’s failure to account for overlapping outage tasks was one of the reasons the Commission found the Sherco avoided-costs offset unsupported.¹⁷³ Likewise, Xcel’s self-serving assumption in this case that no major work would occur during the 2029 outage, other than 27 days of refueling, arbitrarily increases the offset and reduces ratepayers’ refund. The ALJ and the

¹⁶⁷ Ex. OAG-1 at 13–14 (Lee Direct).

¹⁶⁸ SHERCO 3 ORDER at 36.

¹⁶⁹ Ex. Xcel-5, sched. 2 at 3 (Detmer Direct).

¹⁷⁰ Ex. Xcel-5, sched. 2 at 3 (Detmer Direct).

¹⁷¹ See Ex. OAG-6 at 2–4 tbl.1 (listing planned outages at Prairie Island since January 2005).

¹⁷² See Ex. OAG-6 at 2–4 tbl.1 (listing planned outages at Prairie Island since January 2005).

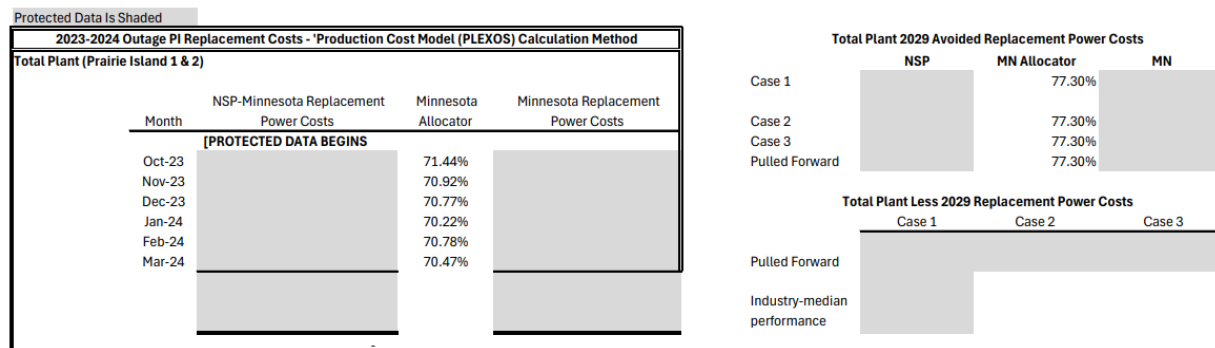
¹⁷³ See SHERCO 3 ORDER at 36 (finding that Xcel had failed to adequately explain “whether any outage tasks could have overlapped with other outage tasks” in future outage for which Xcel was claiming avoided costs).

Commission should find that Xcel’s calculation of avoided 2029 costs is too uncertain to use as an offset against the ratepayer refund for Xcel’s imprudence.

C. Xcel Overstates Minnesota’s Share of the “Supplemental Work” and “Avoided 2029 Costs” Offsets.

For the reasons discussed in the two preceding sections, the Commission should reject Xcel’s proposed offsets for supplemental work and avoided 2029 costs as speculative and unsupported. If the Commission adopts either offset, however, the offset will need to be recalculated to allocate a smaller share to Minnesota.¹⁷⁴ Xcel calculates each offset based on replacement-power costs for its entire system and then converts this overall “NSP” or “Total Company” offset to a Minnesota-specific offset. Xcel accomplishes this conversion by applying a percentage, called an “allocator,” to the Total Company amount.¹⁷⁵ These calculations are shown on the last page of Schedule 2 to the direct testimony of Nicholas Detmer.¹⁷⁶ Figure 4 below reproduces a portion of the public redacted version of that schedule:

**Figure 4 –
Detmer Direct, Schedule 2: Jurisdictional Allocation**



¹⁷⁴ See Ex. OAG-1 at 14 (Lee Direct); Ex. OAG-4 at 13–14 (Lee Surrebuttal).

¹⁷⁵ See Ex. Xcel-5 at 18, sched. 2 at 12 (Detmer Public Direct).

¹⁷⁶ See Ex. Xcel-4, sched. 2 at 990 (Detmer Trade Secret Direct); Ex. Xcel-5, sched. 2 at 12 (Detmer Public Direct).

On the left side, Xcel uses allocators ranging from 70.22% to 71.44% to determine the Minnesota share of the replacement-power costs incurred during the October 2023 outage.¹⁷⁷ On the right side, Xcel uses a much larger allocator, 77.30%, to determine Minnesota’s share of both the Case 1 costs (which are the basis for the “avoided 2029 costs” offset) and the costs allegedly avoided by the supplemental work.¹⁷⁸ In other words, Xcel is relatively stingier when assigning replacement-power costs to Minnesota ratepayers for refunding, and more generous to itself when assigning Minnesota ratepayers a share of the “avoided” costs that offset their refund.

Xcel states that the allocators for the October 2023 replacement-power costs reflect Minnesota’s relative share of total sales in each month.¹⁷⁹ Xcel similarly bases the 2029 allocator on forecasted sales for that year, resulting in the 77.30% figure.¹⁸⁰ Xcel explains that the 2029 allocator is higher because Xcel is projecting a significant increase in Minnesota load, relative to North and South Dakota, largely due to data centers.¹⁸¹

Xcel’s proposal to decrease ratepayers’ refund based on its 2029 sales forecast would unreasonably resolve doubt in favor of the utility.¹⁸² The Commission should instead require Xcel to calculate Minnesota-jurisdictional offsets using a weighted average of the allocators used for the October 2023 outage replacement-power costs, or 70.57%.¹⁸³ Allocating the offsets using actual, known allocators that applied during the October 2023 outage is a more reasonable approach, particularly where Xcel’s alternative would assign more costs to Minnesota ratepayers

¹⁷⁷ See Ex. OAG-1 at 14 (Lee Direct) (citing Ex. Xcel-5, sched. 2 at 12 (Detmer Public Direct)).

¹⁷⁸ See Ex. OAG-1 at 14 & n.2 (Lee Direct) (citing Ex. Xcel-5, sched. 2 at 12 (Detmer Public Direct)).

¹⁷⁹ Ex. Xcel-3 at 5 (Krug Rebuttal).

¹⁸⁰ Ex. Xcel-3 at 5 (Krug Rebuttal).

¹⁸¹ See Ex. Xcel-3 at 5 (Krug Rebuttal).

¹⁸² Ex. OAG-4 at 13 (Lee Surrebuttal).

¹⁸³ See Ex. OAG-4 at 13 & tbl.1 (Lee Surrebuttal).

based on uncertain assumptions about how much new load will materialize in each jurisdiction over the next four years.

D. The Commission Should Reject Xcel’s Historic Performance Adjustment.

Finally, Xcel seeks to roughly halve the refund that remains after applying the “avoided 2029 costs” and supplemental-work offsets by applying a “historic performance adjustment.”¹⁸⁴ Xcel’s basis for this adjustment is that Prairie Island produced 2,577 gigawatt–hours more energy than Xcel forecasted it would during the five-year period from 2018 through 2022, a difference that Xcel characterizes as “delivering over \$50 million dollars in customer benefits.”¹⁸⁵ Xcel does not, however, recommend a \$50 million offset. Instead, it employs a convoluted, arbitrary method to translate this “benefit” into an offset. First, Xcel extends the 2018–2022 evaluation period forward to include the October 2023 outage.¹⁸⁶ Xcel then compares Prairie Island’s operating hours over this combined 2018-through-early-2024 period to the industry median during that period.¹⁸⁷ Xcel calculates that Prairie Island was offline 51 percent more of the time than the median during this period.¹⁸⁸ Finally, Xcel concludes that “49 percent of the net costs should be removed” from any refund.¹⁸⁹

The ALJ and the Commission should firmly reject this offset because it is contrary to regulatory principles. The historic-performance adjustment seeks to give Xcel “extra credit” for operating Prairie Island in a prudent manner prior to the October 2023 incident.¹⁹⁰ However, a

¹⁸⁴ See Ex. OAG-1 at 4–5 & tbl.4 (Lee Direct).

¹⁸⁵ Ex. OAG-1 at 15–16 (Lee Direct) (quoting Ex. Xcel-5 at 24 (Detmer Direct)).

¹⁸⁶ Ex. OAG-1 at 16 (Lee Direct).

¹⁸⁷ Ex. OAG-1 at 16 (Lee Direct); *see also* Ex. Xcel-5, sched. 3 at 1 (Detmer Direct) (showing Prairie Island-to-industry comparison).

¹⁸⁸ Ex. Xcel-5 at 21 (Detmer Direct); *see also id.* sched. 3 at 1 (showing Prairie Island-to-industry comparison).

¹⁸⁹ Ex. OAG-1 at 17 (Lee Direct) (quoting Ex. Xcel-5 at 22 (Detmer Direct)).

¹⁹⁰ The OAG’s testimony did not opine on whether Xcel’s operation of Prairie Island prior to October 2023 was *in fact* prudent, nor is the OAG taking a position on that question now, as Xcel’s

utility has a duty to “operate and maintain [generation plants] in a reasonable and prudent manner consistent with good utility practices.”¹⁹¹ The idea that a utility would be allowed to, essentially, bank “excess” prudence and use it to reduce liability for later imprudent conduct is antithetical to the purpose of regulation.¹⁹² As a regulated electric utility in Minnesota, Xcel is granted an exclusive service area in exchange for operating as a rate-regulated, investor-owned utility subject to the jurisdiction of the Minnesota Public Utilities Commission.¹⁹³ Under this regulatory scheme, Xcel agrees to provide electric service at rates determined by the Commission in exchange for the opportunity to earn its cost of service plus a fair rate of return, including earning a profit on its capital investments such as Prairie Island.¹⁹⁴ This scheme is generally referred to as the “regulatory compact.”¹⁹⁵

Xcel’s ratepayers have held up their end of the regulatory compact by paying Xcel for Prairie Island’s depreciation, return, taxes, and other operating expenses throughout its life.¹⁹⁶ In exchange, they are entitled to all benefits associated with Prairie Island’s performance, and Xcel is expected to prudently operate Prairie Island.¹⁹⁷ To allow an adjustment based on prior prudent operation of Prairie Island would be to double-compensate Xcel’s investors for the Prairie Island’s performance¹⁹⁸—once through recovery of a return on Prairie Island, and again by allowing Xcel to hold back imprudently incurred replacement-power costs.

prudence is not an issue in this case. For the sake of argument, however, the OAG takes this premise as true.

¹⁹¹ SHERCO 3 ORDER at 16.

¹⁹² See Ex. OAG-1 at 17 (Lee Direct); Ex. OAG-4 at 14–15 (Lee Surrebuttal); Ex. DOC-2 at 8 (Golden Surrebuttal); Ex. XLI-3 at 10–11 (Andrews Surrebuttal).

¹⁹³ Ex. OAG-1 at 17 (Lee Direct).

¹⁹⁴ Ex. OAG-1 at 17 (Lee Direct).

¹⁹⁵ Ex. OAG-1 at 17 (Lee Direct).

¹⁹⁶ Ex. OAG-1 at 17 (Lee Direct).

¹⁹⁷ Ex. OAG-1 at 17 (Lee Direct).

¹⁹⁸ Ex. OAG-4 at 15 (Lee Surrebuttal).

There are at least three further reasons that Xcel’s historic-performance adjustment is arbitrary and should be rejected.

First, the idea that Xcel is entitled to an offset for benefits that accrued prior to the October 2023 incident implies that, absent the incident, ratepayers would “owe” Xcel the money for those benefits since there would be no imprudent replacement-power costs to offset. This is an obviously absurd implication, and it underscores that a utility does not get compensated, beyond its approved rate of return, for being “extra” prudent.¹⁹⁹ That fact does not change just because a utility has committed an imprudent act and owes ratepayers a refund.

Second, the choice of periods over which to evaluate Prairie Island’s performance has a large impact on the outcome, and in choosing 2018–2022, Xcel appears to have cherry-picked a favorable period. While Prairie Island achieved a 95 percent average capacity factor in 2018–2022, the plant only achieved average capacity factors of 77 percent, 86 percent, and 91 percent in the three years preceding that.²⁰⁰ In fact, PINGIP’s relatively high capacity factor in 2018–2022 appears to be a historical anomaly, with the plant achieving much lower capacity factors under a variety of other historical periods.²⁰¹ This raises the concern that Xcel selected the 2018–2022 timeframe to maximize the value of the performance adjustment rather than for any principled reason.²⁰²

Third, and relatedly, rewarding Xcel based on Prairie Island’s outage hours over 2018–early 2024 makes no sense because Prairie Island’s performance was *worse* than the industry

¹⁹⁹ Cf. Ex. OAG-1 at 17 (Lee Direct) (explaining that utilities do not get extra credit for prudently operating their plants).

²⁰⁰ Ex. DOC-1 at 16–17 (Golden Direct).

²⁰¹ See Ex. DOC-2 at 4 & tbl.1 (Golden Surrebuttal).

²⁰² Ex. DOC-1 at 17 (Golden Direct).

median over this period.²⁰³ Xcel admits that Prairie Island experienced 51 percent more outage hours than the median during this time.²⁰⁴ It is not reasonable to reward Xcel through an offset for achieving worse-than-average performance. If anything, Xcel’s below-average performance is further evidence of Xcel’s imprudence²⁰⁵ and suggests that no adjustment is appropriate.

III. XCEL SHOULD BEAR ITS OWN COSTS FOR THE CONTESTED CASE.

In setting rates, the Commission must consider both the public’s need for “adequate, efficient, and reasonable service” and the utility’s need for sufficient revenue to meet the cost of furnishing that service.²⁰⁶ In other words, consumers are not obliged to pay all expenses the utility incurs; they are required to pay only for the costs a utility proves are necessary to deliver service in an adequate, efficient, and reasonable manner. This statutory charge requires the Commission to exercise its “legislative” power to determine whether ratepayers or the utility should bear a challenged cost item.²⁰⁷ The Commission’s legislative authority to allow or disallow costs applies to expenses that Xcel incurs in litigating proceedings before the Commission.²⁰⁸ In sum, Xcel may be entitled to have its day in court, but it is not entitled to have ratepayers pay for it.²⁰⁹

²⁰³ Ex. OAG-1 at 17 (Lee Direct).

²⁰⁴ Ex. OAG-1 at 18 (Lee Direct).

²⁰⁵ Ex. OAG-1 at 18 (Lee Direct).

²⁰⁶ Minn. Stat. § 216B.16, subd. 6.

²⁰⁷ See *In re Request of Interstate Power Co.*, 574 N.W.2d 408, 413 (Minn. 1998) (reasoning that “whether to permit the recovery of an item of expense . . . is essentially a policy question of whether the shareholders or the customers should bear the cost”); see also *In re Petition of N. States Power Co.*, 416 N.W.2d 719, 722–23 (Minn. 1987) (“[B]y merely showing that it has incurred . . . expenses, the utility does not necessarily meet its burden of demonstrating that it is just and reasonable that the ratepayers bear the costs of those expenses.”).

²⁰⁸ See, e.g., *In re Application of Interstate Power Co.*, No. E-001/GR-91-605, 1992 WL 348061 at *10 (Minn. P.U.C. June 12, 1992), *appeal dismissed in part per stipulation* (Minn. Ct. App. Jan. 12, 1993), *aff’d*, 500 N.W.2d 501 (Minn. Ct. App. 1993) (requiring utility to bear half its rate-case expenses because Commission found that these expenses benefitted both ratepayers and utility shareholders).

²⁰⁹ See *Roach v. County of Becker*, 962 N.W.2d 313, 322–23 (Minn. 2021) (stating American common law rule that civil litigants ordinarily bear their own attorney fees); see also *In re N. States Power Co.*, MPUC Docket No. E-002/GR-21-630, Findings of Fact, Conclusions, and Order at 23

This contested case has been, at best, only tenuously related to providing adequate, efficient, and reasonable electric service to Xcel’s ratepayers. The Commission referred the matter to CAH to determine “the appropriate amount for Xcel to refund ratepayers due to [its] lack of prudence regarding the October 2023 outage.”²¹⁰ The bulk of the case, however, has been consumed with rebutting dubious offsets by which Xcel seeks to avoid liability for its imprudence. All of Xcel’s offsets are either speculative, contrary to Commission precedent, contrary to bedrock regulation principles, or a combination of the three. Moreover, Xcel has greatly added to the cost of these proceedings by retaining outside counsel and two outside engineers. The purpose of hiring outside engineers appears to have been to lend a veneer of credibility to offsets that Xcel concocted and fed to the engineers.²¹¹

Given the tenuous link between this case and furnishing adequate electric service, as well as the incremental costs Xcel chose to incur, it would not be just or reasonable for ratepayers to bear Xcel’s litigation costs. The Commission will need to take affirmative steps to prevent this from happening, since all utility costs flow into rates to the extent that they are the basis for test-year budgets. The Commission should require Xcel to make a compliance filing after the Commission issues its order listing all costs Xcel incurred in litigating this contested case, including internal employee labor and overhead. Moreover, the Commission should order Xcel,

(July 17, 2023) (disallowing more than 75 percent of compensation of Xcel’s ten highest-paid executives and while noting that Xcel “has been and continues to be free to compensate its employees at levels in excess of its authorized rate recovery if it chooses to do so”).

²¹⁰ REFERRAL ORDER at 8.

²¹¹ See Ex. Xcel-5, sched. 2 at 1–7 (Detmer Public Direct) (attaching IR response, prepared by utility personnel, explaining basis for avoided-2029-costs, supplemental-work, and performance-adjustment offsets); Ex. Xcel-10, sched. 2 at 4 (Bible Direct) (stating that Xcel “provided for review” three scenarios related to the avoided-2029-costs offset as well as “their respective number of future outage days that would be avoided”); Evid. Hrg. Tr. at 65 (Bible) (confirming that Xcel “came up with these scenarios” and provided them to witness for review).

in any future rate case that relies on actual cost data from 2025 or 2026, to show that the internal and external costs for this contested case have been adjusted out of the test year(s).

CONCLUSION

The Commission must not allow Xcel to evade the consequences of its unfortunate mistake, leaving ratepayers to foot the bill. For all the reasons explained above, the ALJ should recommend, and the Commission should take, the following actions:

1. Reject each of Xcel's proposed offsets.
2. Order Xcel to refund \$40.6 million in replacement-power costs with interest at the prime rate, compounded monthly until the refund is fully paid.
3. Order that Xcel may not pass on to ratepayers the costs of the contested-case litigation.
4. Order Xcel to make a compliance filing after the Commission issues its order listing all costs Xcel incurred in litigating this contested case, including internal employee labor and overhead.
5. Order Xcel, in any future rate case that relies on actual cost data from 2025 or 2026, to show that the internal and external costs for this contested case have been adjusted out of the test year(s).

Dated: November 25, 2025

Respectfully submitted,

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