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

INITIAL BRIEF OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY

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Eric F. Swanson
Elizabeth H. Schmiesing
Christopher J. Cerny
Winthrop & Weinstine, P.A.
225 South Sixth Street, Suite 3500
Minneapolis, Minnesota 55402

Lauren Steinhauser
Northern States Power Company
d/b/a Xcel Energy
414 Nicollet Mall
Minneapolis, Minnesota 55401

Attorneys for Xcel Energy

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INTRODUCTION

This proceeding concerns an outage at the Prairie Island Nuclear Generating Plant (Prairie Island or PINGP) in late 2023 and early 2024 following inadvertent damage to power cables (the Event) and whether that outage caused the customers of Northern States Power Company – Minnesota, d/b/a Xcel Energy (Xcel Energy or Company) to pay more for electricity than they would have had the outage not occurred, such that a refund of any excess power costs is appropriate. Resolving that core issue requires answering two central 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 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 are the additional costs for power, if any, incurred by Xcel Energy due to PINGP being offline – involves the evaluation of a number of inputs. It must consider the complexities of the Xcel Energy system, the regional transmission grid and the current energy marketplace. In addition, it 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, and then comparing those costs 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. 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 record in this case demonstrates that Xcel Energy has met its burden to provide evidence supporting the 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. 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 approximately

$7.4 million, plus interest, and it is just and reasonable for the Company to refund customers that amount.

I. BACKGROUND

Before turning to the specific issues in this case, it is helpful to understand the statutory and regulatory structure under which this case arose. Minnesota Statutes provide that the Minnesota Public Utilities Commission (Commission), "in the exercise of its powers . . . to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service."[1] As one part of providing both just and reasonable rates for customers and revenues sufficient to meet the cost of providing service for utilities, Minnesota Statutes and Commission Rules provide for an annual true-up mechanism for utilities' energy purchases and for the costs of fuel used in the generation of electricity.[2] In this annual adjustment process, utilities provide a quantification of the total fuel and market energy costs collected from customers for the prior year, as well as the actual costs incurred by the utility for that year, and then indicate whether the utility has over-collected for the year (meaning a refund to customers is due) or under-collected (meaning a surcharge will be put in place). This process results in customers paying for the costs of the energy they

[1] Minn. Stat. § 216B.16, subd. 6.
[2] Minn. Stat. § 216B.16, subd. 7; Minn. R. 7825.2800 through 7825.2840.

receive and utilities recovering the fuel and market costs they incur in providing that energy – no more and no less.[3]

This case began with the Company's March 1, 2024 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.[4]

After a notice and comment process in which the Commission received comments from the Department of Commerce (Department), Office of the Attorney General – Residential Utilities Division (OAG) and Citizens Utilities Board (CUB), as to all issues other than the impact of the PINGP outage on the Company's costs, the Commission approved the 2023 AAA Report and the Company's proposed $126 million refund to customers. 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

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

considered before requiring any refund of costs incurred during the outage.[5] Therefore, the Commission referred this matter to the Court of Administrative Hearings for this contested case proceeding. Subsequently, the Commission clarified the issues to be addressed in its January 31, 2025 Order Denying Reconsideration and Granting Request for Clarification (Order).

II. STATEMENT OF ISSUES

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 issues are limited to the refund owed to ratepayers for costs that flow through the fuel-clause adjustment report.[6]

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 <u>for replacement power costs in 2023 and 2024</u> 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 <u>for replacement power costs in 2023 and 2024</u> due to Xcel's lack of prudence regarding the October 2023 outage at Prairie Island.[7]

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[5] ORDER APPROVING 2023 FUEL-CLAUSE TRUE-UP REPORT, REQUIRING ADDITIONAL FILINGS, FINDING IMPRUDENCE, AND NOTICE OF AND ORDER FOR HEARING (Nov. 15, 2024).
[6] ORDER at 4, Ordering ¶2.
[7] ORDER at 2 (markings in original).

Second, the Commission clarified that this proceeding would not address other issues potentially related to the outage such as the impact of any de-rating of PINGP on capacity costs, but that any such issues would be addressed in the Company's ongoing electric rate case.[8]

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.[9]

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

1. 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?

2. Are there benefits or offsets that mitigate any additional power costs in whole or in part?[10]

III. STATEMENT OF FACTS

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

The Prairie Island Plant is a two-unit, nuclear-powered, electric generating station located in Red Wing, Minnesota.[11] 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

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[8] ORDER at 4, Ordering ¶2.
[9] ORDER at 4, Ordering ¶3.
[10] Ex. Xcel-1 at 9 (Krug Direct).
[11] Ex. Xcel-1 at 4 (Krug Direct).

baseload energy service, and is among the most reliable resources in the Company's fleet.[12] 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.[13]

Xcel Energy customers have benefited from this consistent and reliable operation of PINGP over the last several years.[14] The strong performance noted above included periods of extreme weather, including the 2019 polar vortex, the 2021 Winter Storm Uri, and others, where reliable energy supply was critical.[15] In total, over the five year period from 2018 through 2022, PINGP generated approximately 2,577 GWh above the Company's forecasted amount, resulting in substantial benefits to our customers, compared to normal operating performance over that time period, benefiting Xcel Energy customers by more than $50 million.[16] Customers exclusively benefit from this strong performance because they do not pay anything incremental—and the Company does not receive incremental compensation—for it.

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

[12] Ex. Xcel-1 at 4 (Krug Direct).
[13] 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).
[14] Ex. Xcel-1 at 4 (Krug Direct); Ex. Xcel-4 at 21-22 (Detmer Direct).
[15] Ex. Xcel-1 at 4 (Krug Direct); Ex. Xcel-4 at 21 (Detmer Direct).
[16] Ex. Xcel-1 at 4-5 (Krug Direct); Ex. Xcel-4 at 21-22 (Detmer Direct).

fact, while Xcel Energy itself has a large electric generation portfolio,[17] PINGP alone represents approximately 13 percent of the energy generated within the Minnesota region of the MISO North market.[18] This region 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. That means the Company is often price isolated from the broader energy market and often must address disruptions within its generation portfolio with its own resources, rather than purchasing additional power on the MISO market.[19] This is precisely what happened 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.[20]

B. The MISO Market

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. 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

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[17] Ex. Xcel-4 at 13 (Detmer Direct).
[18] Evidentiary Hearing Transcript (Tr.) at 56 (Detmer).
[19] Tr. at 54-55 (Detmer).
[20] Tr. at 56 (Detmer)

> market, and the second pass is the Real-Time market. Starting with the Day-Ahead market, Market Participants [such as Xcel Energy] 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 market sell energy at their LMP. The LMP is specific to generators and loads on the transmission grid, called Commercial Pricing nodes.[21]

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.[22] And, as the name implies, 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.[23] 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.[24] Regarding transmission capacity, there are areas of constraints of the transmission system,

[21] Ex. Xcel-4 at 3 (Detmer).
[22] Ex. Xcel-4 at 4 (Detmer Direct).
[23] Ex. Xcel-4 at 10 (Detmer Direct).
[24] Ex. Xcel-4 at 10 (Detmer Direct).

and at times the system can approach its maximum capacity.[25] When this occurs, the market responds by disfavoring generation located in areas of constrained capacity.[26]

Finally, it is important to recognize that 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.[27] Rather, as to the Xcel Energy generation facilities, when those 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.[28] 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 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

[25] Ex. Xcel-4 at 10 (Detmer Direct).
[26] Ex. Xcel-4 at 10 (Detmer Direct).
[27] Ex. Xcel-4 at 10 (Detmer Direct).
[28] Ex. Xcel-4 at 4-6, 10 (Detmer Direct).

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.[29]

This scenario is illustrated as follows:[30]

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

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

[29] Ex. Xcel-4 at 4-5 (Detmer Direct).
[30] Ex. Xcel-4 at 6, Table 1 (Detmer Direct).

Company's generation portfolio, such as PINGP, as those resources effectively hedge customers' exposure to higher and more volatile LMP prices.[31]

C. The Event And Subsequent Outage

On October 19, 2023, a team working on a cable-replacement project at PINGP inadvertently struck a direct current (DC) power cable bundle containing control cables, severing those cables (the Event).[32] Those cables control power to assets required to operate both units of PINGP at power.[33] At the time of the Event, PINGP Unit 2 was offline, in a planned refueling outage.[34] However, the Event caused PINGP Unit 1 to also shut down, and Unit 1 did not return to full service until January 30, 2024, meaning a total outage time for Unit 1 of 103 days.[35] In addition, while Unit 2 was already offline when the Event occurred, the work required to replace and test the control cables added 57 days to the length of the Unit 2 outage.[36] No party to this action presented testimony that either 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.[37]

D. The Company's Work Following The Outage

After the Event, the Company conducted an inspection of the cables and an Operational Decision-Making Issue (ODMI) evaluation that evaluated various options for

[31] Ex. Xcel-4 at 10-11 (Detmer Direct).
[32] Ex. Xcel-1 at 5 (Krug Direct).
[33] Ex. Xcel-1 at 5 (Krug Direct).
[34] Ex. Xcel-1 at 5 (Krug Direct).
[35] Ex. Xcel-1 at 6 (Krug Direct).
[36] Ex. Xcel-1 at 7 and Schedule 3 (Krug Direct).
[37] *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).

cable repair and replacement.[38] 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.[39] The Company's decision was based on the overall condition of the cable jackets, evidence of corrosion and degraded insulation.[40] Based on this analysis, the Company determined that replacing the cables, rather than repairing them, was the best course of action.[41] None of the parties to this action provided testimony contesting the Company's position that replacement, rather than repair, was appropriate.[42]

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. The Company sent portions of the damaged cables to the Electric Power Research Institute (EPRI) for testing and assessment.[43] 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.[44] EPRI found that the control cable samples had been subject to moisture and overheating, and some locations had cracked jackets.[45] EPRI also determined that the thermal resistance of the backfill was

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[38] Ex. Xcel-10, Schedule 2 at 2 (Bible Direct).
[39] Ex. Xcel-10, Schedule 2 at 2 (Bible Direct).
[40] Ex. Xcel-1 at 5 (Krug Direct).
[41] Ex. Xcel-1 at 5 (Krug Direct).
[42] 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).
[43] Ex. Xcel-13, Schedule 2 at 4 (Hiser Direct).
[44] Ex. Xcel-13, Schedule 2 at 4 (Hiser Direct).
[45] Ex. Xcel-13, Schedule 2 at 5 (Hiser Direct).

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.[46]

Company expert witness Mr. Carl Bible, a nuclear industry professional with over 45 years of nuclear industry experience, including substantial experience with power distribution, switchgear, cables, transformers, generators, instrument and control systems, associated regulatory requirements, and root cause and failure analysis, as well as direct experience with control cable failures,[47] also provided testimony.[48] Mr. Bible determined 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.[49]

Company expert witness Dr. Allen Hiser, who has over 30 years of experience with the Nuclear Regulatory Commission (NRC) focusing on aging management evaluations in the context of license renewal (LR) and subsequent license renewal (SLR),[50] testified that

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[46] Ex. Xcel-13, Schedule 2 at 5 (Hiser Direct).

[47] Ex. Xcel-10 at 1, Schedule 1 (Bible Direct).

[48] During the Evidentiary Hearing of this matter, the Department of Commerce cross-examined Mr. Bible regarding various actions taken by his former employer, Florida Power & Light, that were considered imprudent by various regulators and advisory bodies. As discussed previously, and as noted by the Commission in its Order, the prudency of the Company's action with respect to the Event is not at issue here, and Mr. Bible has provided no testimony as to whether the Company acted prudently with respect to the Event. And, contrary to Department counsel's statement at the hearing, nothing in any of the reports discussed at the hearing are relevant to Mr. Bible's credibility. Tr. at 75-85.

[49] Ex. Xcel-10, Schedule 2 at 3 (Bible Direct).

[50] Ex. Xcel-13 at 1, Schedule 1 (Hiser Direct).

replacement of the cables was a prudent measure that will ensure future reliability of the control cables.[51] Dr. Hiser also testified that the cables would likely have been subject to replacement during the SLR operating period, the period of operation that occurs after a second license renewal.[52] The Company intends to file a SLR Application for the Plant in late 2026.[53] 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.[54] 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.[55] Had these cables been included in the 20 percent sampled, it is highly likely that the degradation would be identified at that time.[56] It is likely that corrective actions would include replacement of the cables, similar to the actions taken by the Company following the Event.[57] This planned replacement, however, would likely have occurred as part of a planned dual unit outage.[58]

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

[51] Ex. Xcel-13, Schedule 2 at 5 (Hiser Direct).
[52] Ex. Xcel-13 at 2 and Schedule 2 at 6, n. 2 (Hiser Direct).
[53] Ex. Xcel-13, Schedule 2 at 3, 11 (Hiser Direct).
[54] Ex. Xcel-13, Schedule 2 at 11-12 (Hiser Direct).
[55] Ex. Xcel-13, Schedule 2 at 11-13 (Hiser Direct).
[56] Ex. Xcel-13, Schedule 2 at 13 (Hiser Direct).
[57] Ex. Xcel-13, Schedule 2 at 13 (Hiser Direct).
[58] Ex. Xcel-13, Schedule 2 at 13 (Hiser Direct).

cables.[59] If the condition of the cables that were tested and sampled was similar to that of the 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.[60]

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.[61] 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.[62] 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.[63]

The common thread among these scenarios is that, at some point, the cables would need to be replaced, either during a planned dual unit outage, if the degradation of the cables was discovered in the course of the SLRA process, or during a future unplanned dual unit outage if the degradation was not discovered. Either way, 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.

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[59] Ex. Xcel-13, Schedule 2 at 13 (Hiser Direct).
[60] Ex. Xcel-13, Schedule 2 at 14 (Hiser Direct).
[61] Ex. Xcel-13, Schedule 2 at 13-14 (Hiser Direct).
[62] Ex. Xcel-13, Schedule 2 at 13-14 (Hiser Direct).
[63] Ex. Xcel-13, Schedule 2 at 13-14 (Hiser Direct).

The majority of the outages planned by the Company are single unit, rather than dual unit.[64] 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[65] and the cooling water system pipe replacement.[66] By performing this work now, 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.[67] 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.[68]

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

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.[69] To the extent this "replacement power" cost more than customers would have paid absent the Event and outage, and to the extent those

[64] Ex. OAG-1, Schedule 2 at 4 (Lee Direct).
[65] 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).
[66] 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).
[67] Ex. DOC-1, Schedule 1 at 2 (Golden Direct).
[68] Ex. Xcel-3 at 6 (Krug Rebuttal); Ex. DOC-1 at 13 (Golden Direct).
[69] *See* Tr. at 56 (Detmer).

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. 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.

1. Power Costs

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.[70] 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.[71] 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. The record contains one method for estimating any such additional power costs – the use of production cost modeling using the PLEXOS® production cost model. 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).

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[70] Ex. Xcel-4 at 14 (Detmer Direct); Ex. DOC-1 at 6 (Golden Direct).
[71] Ex. Xcel-4 at 14 (Detmer Direct); Ex. DOC-1 at 6 (Golden Direct).

a. Production Cost Modeling

Xcel witness Mr. Detmer is the Company's Director of Market Operations and Analytics.[72] Mr. Detmer is a licensed professional engineer with 30 years of industry experience and over 20 years of experience performing the type of analytics and production cost modeling he conducted for this case.[73] As Mr. Detmer explained, 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."[74] He further explained 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.[75] 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.[76] These models are also used to conduct backward looking analyses, such as evaluating previous decisions or events, by creating a counterfactual study – for example, to develop what the overall system cost would have been under a different set of facts.[77] When used with the goal of minimizing costs for electric power, as was done in this proceeding, the modeling tool incorporates a

[72] Ex. Xcel-4 at 1 (Detmer Direct).
[73] Ex. Xcel-4 at 1 (Detmer Direct.); Tr. at 52 (Detmer).
[74] Ex. Xcel-4 at 11 (Detmer Direct).
[75] Ex. Xcel-4 at 11 (Detmer Direct).
[76] Ex. Xcel-4 at 11 (Detmer Direct).
[77] Ex. Xcel-4 at 11-12 (Detmer Direct).

number of factors, including fuel costs, non-fuel operations and maintenance costs, generating unit minimum run times, maximum capacity at various generating units.[78]

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.[79] For studies of power costs over a moderate term length of between one month and five years, Xcel Energy uses PLEXOS.[80] 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.[81]

Using this tool, the Company modeled the cost of replacement power 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.[82] The difference between these two cases provides a reliable estimate of the additional power costs incurred by the Company due to the PINGP outage, as discussed further, below.

b. LMP Method

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 even attempt to

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[78] Ex. Xcel-4 at 12-13 (Detmer Direct).
[79] Ex. Xcel-4 at 14 (Detmer Direct).
[80] Ex. Xcel-4 at 14 (Detmer Direct).
[81] Ex. Xcel-8 at 7 (Detmer Rebuttal).
[82] 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.

determine the amount of additional cost that may have been incurred during the outage time. Rather, the LMP Method assumes that, had PINGP been available, it would have had no impact on the other generation assets on the Xcel Energy system.[83] That is, it assumes that the generation at all of Xcel Energy's other generation facilities would not change, with or without PINGP operating.[84] Therefore, it also 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.[85] This method then uses this resulting alleged "lost revenue" differential as a proxy for the replacement power costs.[86]

2. Value Of Offsets And Benefits

a. Offsets For Avoided Outages

As discussed above, the record establishes two different "offsets" that should be considered 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. For each of these, the Company again utilized PLEXOS production cost modeling to estimate the value to customers of avoiding these future outage times.[87] The Department disagreed that the future avoided extended outage should be considered in this

[83] Ex. Xcel-8 at 9 (Detmer Rebuttal).
[84] Ex. Xcel-8 at 9 (Detmer Rebuttal); Ex. XLI-2 at 11(Andrews Direct).
[85] Ex. XLI-2 at 11(Andrews Direct).
[86] Ex. Xcel-8 at 9 (Detmer Rebuttal); Ex. XLI-2 at 11-12 (Andrews Direct).
[87] Ex. Xcel-4 at Schedule 2 (Detmer Direct).

proceeding.[88] However, 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.[89] And, while other parties disputed whether either offset should be considered, no party provided an alternative means of valuing these offsets, should they be considered.

b. Benefits Of Historic Performance

As discussed above, PINGP has a history of strong performance that has provided substantial benefits to Xcel Energy customers. In fact, over the five-year period from 2018 through 2022, PINGP generated approximately 2,577 GWh above the Company's forecasted amount.[90] All of the benefit of the Company's performance redounded to customers. Compared to the forecasted normal operating performance over that time period, this strong performance saved customers more than $50 million during that time.[91] The Company has proposed a historical performance adjustment that does not seek to recognize all of that customer benefit.[92] Rather, 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 recommends be applied in determining any final refund amount, as discussed further,

[88] Ex. DOC-2 at 13 (Golden Surrebuttal).
[89] Ex. Xcel-3 at 6 (Krug Rebuttal); Ex. DOC-1 at 13 (Golden Direct).
[90] Ex. Xcel-1 at 4-5 (Krug Direct); Ex. Xcel-4 at 21-22 (Detmer Direct).
[91] Ex. Xcel-1 at 4-5 (Krug Direct); Ex. Xcel-4 at 21-22 (Detmer Direct).
[92] Ex, Xcel-3 at 7 (Krug Rebuttal).

below.[93] 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.[94]

IV. ARGUMENT

A. The Company's Production Cost Modeling Provides The Most Reasonable Estimate Of The Additional Power Costs Incurred Due To PINGP Being Offline

As the Commission clarified in its Order, it 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.[95] 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. The record demonstrates the Company's PLEXOS modeling provides the most

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[93] Ex. Xcel-1 at 12-13 (Krug Direct); Ex. Xcel-4 at 21-22 and Schedule 3 (Detmer Direct).
[94] Ex. Xcel-3 at 8 (Krug Rebuttal).
[95] ORDER at 3. The Commission further clarified that parties should also develop a record regarding any offsets or benefits that should be considered in determining a final refund amount, if any. *Id*.

reliable estimate of replacement power costs in this proceeding and quantifies those costs as $34.3 million.

1. The Company's Production Cost Modeling Reliably Estimates The Cost Difference For Xcel Energy Due To The Loss Of A Resource Such As PINGP

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.[96] However, 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.[97] The difference between the total costs in the change case and the total costs in the base case results in the "replacement power cost."

The Company utilized the PLEXOS production cost model to develop the change case and base case results. This 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

[96] Ex. Xcel-4 at 14-15 (Detmer Direct).
[97] Ex. Xcel-4 at 16 (Detmer Direct).

proceedings that estimate replacement power costs.[98] In fact, 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.[99] The PLEXOS model utilizes a complex time-series decision tree that seeks to determine the lowest cost series of decisions over the study period.[100] 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.[101]

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 variable operations and maintenance costs for every generator on the Xcel Energy system.[102] The Company then ran the case such that *every generator operated at its actual generation level for every hour of the outage period*.[103] Running the model in this manner produced a highly accurate representation of the Company's actual production costs and

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[98] Ex. Xcel-4 at 15 (Detmer Direct); Tr. at 57 (Detmer).
[99] *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).
[100] Ex. Xcel-4 at 15 (Detmer Direct).
[101] Ex. Xcel-4 at 15 (Detmer Direct).
[102] Ex. Xcel-4 at 16 (Detmer Direct); Ex. Xcel-8 at 7-8 (Detmer Rebuttal).
[103] Ex. Xcel-8 at 8 (Detmer Rebuttal).

the Company then could run the model to develop the total system costs for energy over the outage period.[104]

Once this base case was established, the Company modified it by making PINGP available over this same time period.[105] Specifically, the Company assumed 100 percent availability of this low cost resource for every hour of every day of the outage period.[106] The Company then allowed the model to redispatch generating units and to make additional sales, again to optimize the results, thereby minimizing overall system costs.[107]

Next, 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.[108]

2. Intervenor Criticisms Of The Company's Incremental Power Cost Estimate Lack Merit

The Department and XLI both recommend that the Commission not rely on the Company's PLEXOS modeling estimate in this proceeding. 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."[109] However, he stated that the Company's use of the model in this case was

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[104] Ex. Xcel-4 at 16 (Detmer Direct); Ex. Xcel-8 at 8 (Rebuttal Direct).
[105] Ex. Xcel-4 at 16 (Detmer Direct); Ex. Xcel-8 at 3, 13 (Detmer Rebuttal).
[106] Ex. Xcel-4 at 16 (Detmer Direct); Ex. Xcel-8 at 3, 13 (Detmer Rebuttal).
[107] Ex. Xcel-8 at 11-12 (Detmer Rebuttal).
[108] Ex. Xcel-4 at 16 and Schedule 2, Attachment C (Detmer Direct).
[109] Ex. DOC-3 at 14 (Rakow Surrebuttal).

"internally inconsistent" and that the Company's model outputs "conflict with what is known in the real world."[110] Due to these purported flaws, Dr. Rakow instead recommended the Commission rely on the LMP Method as a "sufficiently reasonable" means of calculating an appropriate refund of power costs in this case.[111] However, Dr. Rakow's alleged flaws are not valid, and PLEXOS modeling remains the best method to address the questions posed in this docket.

First, Dr. Rakow observes that the Company's PLEXOS modeling did not attempt to calculate and then incorporate a change in LMPs between the base case and the change case, and he claims that this 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] However, maintaining uniform LMPs is the norm, not some sort of error. The Company and the Commission routinely rely on PLEXOS modeling in fuel clause and other proceedings to estimate replacement costs and those PLEXOS models include a variety of outages where LMPs are not changed during the outage periods,[113] just as the Company modeled here.

Further, any change in LMPs due to the inclusion of PINGP is a secondary effect and difficult, if not impossible, to calculate.[114] Therefore, rather than speculate as to the magnitude of any change in LMP, the Company's modeling assumed no change.[115] If

[110] Ex. DOC-3 at 5, 14 (Rakow Surrebuttal).
[111] Ex. Xcel-3 at 19 (Rakow Surrebuttal).
[112] Ex. Xcel-3 at 5 (Rakow Surrebuttal).
[113] Tr. at 56-57 (Detmer).
[114] Ex. Xcel-8 at 4-5 (Detmer Rebuttal); Tr. at 57 (Detmer).
[115] Ex. Xcel-8 at 5 (Detmer Rebuttal); Tr. at 57 (Detmer).

anything, this assumption over-estimates replacement power costs. As 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.[116] Therefore, leaving LMPs unchanged between the two cases, as the Company did here, exaggerates the replacement power costs in customers' favor.[117]

Second, Dr. Rakow claims that the Company's model outputs "conflict with what is known in the real world."[118] To support this assertion, Dr. Rakow looked at LMPs across MISO during the time of the outage. Based on his review of those LMPs, Dr. Rakow 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.[119] However, in the "real world," Xcel Energy *did* see the generation at its other generation resources increase 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.[120] In other words, contrary to Dr. Rakow's suggestion, the loss of PINGP's energy *was* replaced by Xcel Energy's own generation.

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[116] Tr. at 57 (Detmer).
[117] Tr. at 57 (Detmer).
[118] Ex. DOC-3 at 14 (Rakow Surrebuttal).
[119] Ex. DOC-3 at 13 (Rakow Surrebuttal).
[120] Tr. at 56 (Detmer).

This increase in generation from Xcel Energy generating units, as shown in both the real world and in the Company's modeling results, makes sense. As Mr. Detmer testified, Xcel Energy operates in a Narrow Constrained Area within the MISO North region.[121] 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.[122] In its 2022 filing, the IMM states that the Minnesota region, relevant here, 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, meaning it must address generation disruptions in the area with its own resources.[123] The Company's 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.

XLI offers an additional, unsupported critique of 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.[124] XLI offers no specific criticism or alleged errors in the Company's development of the base case and in fact acknowledges that it incorporated the actual output

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[121] Tr. at 54 (Detmer).
[122] Tr. at 54 (Detmer).
[123] Tr. at 55 (Detmer).
[124] Ex. XLI-2 at 4-5 (Andrews Direct). XLI witness Mr. Andrews, like Department witness Mr. Rakow, claimed the Company's modeling did not produce rational results, since he asserted "the generation output of Xcel's other resources should have been largely unchanged" with or without the energy supplied by PINGP. *Id.* at 3. The Company has already addressed this perceived flaw and will not repeat that discussion here.

from the generating units modeled.[125] In contrast, 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.[126] These inputs then, together with the use of *actual generation on an hour-by-hour basis*, do result in a highly accurate representation of the Company's power costs during the PINGP outage.[127]

In summary, 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 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.

3. The LMP Method Relies On An Unrealistic Scenario That Overstates The Company's Replacement Power Costs

In contrast to Commission precedent and the Department's prior approaches in similar cases, 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 would have been earned had [PINGP] been operating as usual."[128] As such, the LMP

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[125] Ex. XLI-2 at 4 (Andrews Direct).
[126] Ex. Xcel-8 at 7-8 (Detmer Rebuttal).
[127] Ex. Xcel-8 at 8 (Detmer Rebuttal).
[128] Ex. XLI-2 at 15 (Andrews Direct); *see also* Ex. DOC-3 at 19 ("the LMP calculation method recommended by Mr. Andrews provides a sufficiently reasonable result.").

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. The scenario is wildly unrealistic and overstates energy costs actually incurred by the Company and its customers.

As Company witness Mr. Detmer explained, 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.[129] 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.[130] However, 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.[131] For example, 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.[132] Adding such low-cost resources back into the Company's portfolio means that the Company and

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[129] Ex. Xcel-1, Schedule 2 (Krug Direct); Ex. Xcel-8 at 9 (Detmer Direct).
[130] Ex. Xcel-8 at 9 (Detmer Rebuttal).
[131] Ex. Xcel-8 at 9 (Detmer Rebuttal).
[132] Ex. Xcel-4 at 10 (Detmer Direct).

customers will pay less for power, and sometimes substantially less, than paying market prices, as implied by the LMP Method.[133]

As noted, the LMP Method supported by the Department and XLI 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 – a terribly unrealistic scenario.[134] This allows the LMP Method to estimate "the *net revenue* that would have been earned had [PINGP] been operating as usual," as described by XLI witness Mr. Andrews.[135] That also means that the LMP Method must assume that all PINGP power produced during that time, while it would have had production costs below the LMP price in order to clear the market, 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) power.

There is a simple way to check the reasonableness of using the LMP Method to estimate the customer impact of the PINGP outage. Because the LMP Method assumes every kilowatt hour of power from PINGP would have been sold on the MISO Market at LMP pricing, it also assumes that the *loss* of PINGP power had no impact whatsoever on the other Xcel Energy generating assets. In other words, the LMP Method assumes those other generating assets would have provided the exact same amount of production, with or without PINGP operating. That result is not just illogical, it is contrary to what the

[133] *See* Ex. Xcel-4 at 4-10 (Detmer Direct) for a discussion of different scenarios and how those scenarios impact customer cost.
[134] Tr. at 56 (Detmer).
[135] Ex. XLI-2 at 15 (Andrews Direct) (emphasis added).

Company experienced. As Company witness Mr. Detmer testified, 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.[136] For all of these reasons, the LMP Method does not provide a reasonable proxy for the replacement power costs incurred due to the PINGP outage. Therefore, in calculating replacement power costs, the only reasonable approach supported by the evidence in this record is to rely on the output of the PLEXOS model.

B. Customers Will Not Be Exposed To The Costs Of A Future Extended Outage, Due To The Company's Full Replacement Of The Impacted Cables

As discussed in the testimony of Company witnesses Bible and Hiser and described above, based on the discovered condition of the cut cables, the cables would have needed to be replaced at some point in the future—either as a result of a spontaneous failure or as a result of a corrective order during the SLR process. Because the cables would have needed to be replaced in the future, the replacement of the cables in 2023 avoided the inevitable future power replacement costs. 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. The most conservative scenario assumed a planned replacement of the cables resulting from inspection and testing during the SLRA process and — resulted in the lowest replacement

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[136] Tr. at 56 (Detmer).

power costs of the scenarios presented. The scenarios leading to higher recovery of 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.

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.[137] However, this objection is largely irrelevant, as the Company is not proposing to seek recovery of the amounts associated with either of the spontaneous failure scenarios.

The OAG, through the testimony of witness Shoua Lee, raised the same issue,[138] and also argues 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, such that it would then not therefore drive the length of a future outage.[139] Finally, 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.[140] The Company addresses these concerns in turn below.

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[137] Ex. DOC-1 at 11 (Golden Direct).
[138] Ex. OAG-1 at 13-14 (Lee Direct).
[139] Ex. OAG-1 at 13-14 (Lee Direct).
[140] Ex. OAG-1 at 14-15 (Lee Direct).

1. No NRC Requirements Or Guidance, And No Industry Standards, Require That DC Control Cables Be Tested Or Inspected At This Stage In The Plant's Operations

Company witnesses Bible and Hiser, based on their decades of experience in the nuclear industry, 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. 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).[141] 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.[142] 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.[143]

Only the OAG responded to this point, and responded purely with speculation that *at some future time*, the NRC's requirements *might* change to require testing or inspection of the DC control cables.[144] Beyond the fact that this speculation should be given little weight, it also is irrelevant. While it is possible that regulations might change in the future,

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[141] Ex. Xcel-14 at 2 (Hiser Rebuttal).
[142] Ex. Xcel-14 at 2 (Hiser Rebuttal).
[143] Ex. Xcel-11 at 4 (Bible Rebuttal).
[144] Ex. OAG-4 at 9 (Lee Surrebuttal).

there is, of course, no possible scenario where regulations would change in such a way to require retroactive inspections or testing. Ms. Lee acknowledges that by stating that any future cable failure or replacement would need to be assessed under "the NRC standards and guidelines applicable *at that time* . . . ."[145] 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 specifically was not aware of any such change that would retroactively require a different management approach to such cables.[146]

Regardless of the lack of requirements, the Company has in fact 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.[147] The record contains no evidence whatsoever that the Company should have performed additional inspections or testing of the cables.

2. Had It Been Conducted At A Future Time, The Cable Replacement Work Would Be Considered Critical Path And Would Have Driven The Length Of A Future Outage

The OAG's contention that the Company failed to demonstrate that the cable replacement work would not be critical path if conducted concurrently with other work, and would therefore not drive the length of a future outage, is misplaced. Mr. Bible provided a thorough discussion of the sequencing of the cable replacement project, pointing

[145] Ex. OAG-4 at 9 (Lee Surrebuttal).
[146] Tr. at 133 (Lee Cross).
[147] Ex. Xcel-14 at 3-4, Schedule 1 (Hiser Rebuttal).

out when concurrent projects could be conducted and referenced an illustrative timeline depicting these concepts.[148]

By her own admission, Ms. Lee is not qualified to opine on engineering-related matters.[149] While Ms. Lee contends that the issue of concurrent work is a "non-engineering" issue, this is simply incorrect. As Mr. Bible testified, determining which work can be conducted concurrently at a nuclear plant is *unquestionably* an engineering issue.[150] As Mr. Bible testified:

> 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.[151]

In response to discovery, the Company noted that refueling activities and major projects typically drive outage schedules, meaning that they are considered "critical path."[152] During the Evidentiary Hearing, Ms. Lee admitted she had no basis to disagree with the Company's response on this point.[153] Ms. Lee's baseless and speculative opinions on which nuclear projects can be done concurrently should be given no weight.

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[148] Ex. Xcel-11 at 6-7, Schedule 1 at 110 (Bible Rebuttal).
[149] Ex. OAG-1 at 13 (Lee Direct); Tr. at 124 (Lee Cross) (agreeing that neither the Administrative Law Judge nor the Commission should consider her opinion on any matters within the province of engineering).
[150] Ex. Xcel-11 at 5 (Bible Rebuttal).
[151] Ex. Xcel-11 at 6 (Bible Rebuttal).
[152] Ex. OAG-1, Schedule 2 (Lee Direct).
[153] Tr. at 132-33 (Lee Cross).

3. The Allocators Used To Calculate The Avoided Replacement Power Costs Associated With The Cable Replacement Were Appropriate

The OAG questioned the use of a higher allocator than that applied in October 2023 and 2024 for the calculation of avoided replacement power costs.[154] Because the avoided replacement costs would have occurred in the future, a jurisdictional allocator for 2029 was calculated by the Company.[155] 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.[156] The OAG continued to object to the calculation, claiming that the forecasted load may not come on line as anticipated.[157] Ms. Lee points 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, suggesting that the Commission will closely monitor developments of data centers in the Company's service area.[158] Nothing about this requirement, however, supports the OAG's stated concern regarding load. In any event, due to the nature of the proposed offset, estimates are necessary. The Company specifically addressed this issue at the outset by noting that the exact timing and duration of the avoided or shortened outages must be estimated and that a general estimate of

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[154] Ex. OAG-1 at 14-15 (Lee Direct).
[155] Ex. Xcel-3 at 5 (Krug Rebuttal).
[156] Ex. Xcel-3 at 5 (Krug Rebuttal).
[157] Ex. OAG-4 at 12 (Lee Rebuttal).
[158] Ex. OAG-4 at 12 (Lee Surrebuttal).

replacement power costs if those outages actually occurred.[159] That said, "[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."[160]

The Company's estimate of avoided power costs due to the avoided future cable replacement was conservative, and it is uncontested 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.

C. Customers Will Avoid Future Outage Related Costs Due To The Company Performing Certain Additional Work Beyond The Cable Replacement

As discussed above, the Company used the unplanned dual unit outage to perform work that had been slated for a later planned outage. By completing two of those projects during that outage, both of which would have required a dual unit outage, the Company avoiding 2.2 days of future outage time, saving approximately $500,000 in future costs.[161] Department witness Golden agrees with this calculation.[162] The OAG, however, took a different position, claiming that the Company failed to establish that the pulled-forward work could not have been completed in future outages without lengthening that future

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[159] Ex. Xcel-1 at 17 (Detmer Direct).
[160] Ex. Xcel-1 at 17 (Detmer Direct).
[161] 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. Ex. Xcel-3 at 6 (Krug Rebuttal); Ex. DOC-1, Schedule 1 at 2 (Golden Direct).
[162] Ex. DOC-2 at 2 (Golden Surrebuttal).

outage period and that the Company's assumed labor hours per outage day used to calculate the saved outage days appeared to be arbitrary.[163] These objections are again unsupported.

1. The Two Projects Included In The Pulled-Forward Work Calculation Would Be Critical Path And Would Have Determined The Length Of The Future Avoided Outage

Ms. Lee's contention that the Company failed to demonstrate that the two projects included in the calculation of saved outage days could not have been completed in future outages without lengthening that future outage is speculative and not supported by any evidence in the record. As noted above, Ms. Lee is not qualified to opine on engineering related matters.[164] Nonetheless, 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.[165] While Ms. Lee seems to concede that the two pulled-forward projects were critical path, she baselessly speculates that it could have been completed concurrently with other critical path work.[166] Ms. Lee's testimony demonstrates a misunderstanding of the nature of "critical path" work.

During the Evidentiary Hearing, Ms. Lee admitted that her 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.[167] Ms. Lee further acknowledged that the relevance of

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[163] Ex. OAG-4 at 2 (Lee Surrebuttal).
[164] Ex. OAG-1 at 13 (Lee Direct); Tr. at 124 (Lee Cross) (agreeing that neither the Administrative Law Judge nor the Commission should consider her opinion on any matters within the province of engineering).
[165] Ex. OAG-1 at 9 (Lee Direct).
[166] Ex. OAG-1 at 9 (Lee Direct).
[167] Tr. at 131-32 (Lee Cross).

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.[168] 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.[169] 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."[170] Ms. Lee's testimony 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.[171] This is not evidence, but mere speculation.

The Company understands that it bears the burden of proof to demonstrate that the refund due ratepayers should be offset by the value of the avoided outage days. That said, the standard of proof for contested case hearings is preponderance of the evidence.[172] 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.[173]

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[168] Tr. at 131-32 (Lee Cross).
[169] Tr. at 126 (Lee Cross).
[170] Tr. at 127 (Lee Cross).
[171] Tr. at 129 (Lee Cross).
[172] Minn. R. 1400.7300, subp. 5.
[173] Tr. at 127 (Lee Cross).

2. The Estimated Labor Hours Per Outage Day Used By The Company Was Appropriate And The 2.2 Days Of Avoided Outage Due To The Pulled-Forward Work Was A Conservative Estimate

The OAG also took issue with the Company's estimate of 1,050 labor hours per outage day, arguing that it was "arbitrary."[174] Ms. Lee contends that the relevant outage for this consideration is the future outage from which this work was pulled forward rather than the October 2023 outage.[175] Ms. Lee further relies 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.[176] The Company based its estimate of labor hours per outage day on the dual unit outage resulting from the Event.[177] By contrast, the outages Ms. Lee relied on for her comparison were all single unit outages,[178] and the pulled-forward work identified by the Company as leading to avoided outage days requires a dual unit outage.[179] Ms. Lee is comparing apples to oranges. And as noted by Mr. Bible, using data from an actual outage to calculate avoided days is not arbitrary.[180]

Ms. Lee also failed to address the Company's uncontested statement that its calculation of avoided outage days did not include the additional outage days that would be required to shut down and restart the reactor in its estimate.[181] Overall, the Company's

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[174] Ex. OAG-1 at 10 (Lee Direct).
[175] Ex. OAG-1 at 10 (Lee Direct).
[176] Ex. OAG-1 at 11 (Lee Direct).
[177] Ex. Xcel-4, Schedule 2 at 9 (Detmer Direct); Ex. Xcel-11 at 8 (Bible Rebuttal).
[178] Ex. OAG-4 at 6 (Lee Surrebuttal); Tr. at 133 (Lee Cross).
[179] Ex. Xcel-11 at 7-8 (Bible Rebuttal).
[180] Ex. Xcel-11 at 8 (Bible Rebuttal).
[181] Ex. OAG-4 at 6 (Lee Surrebuttal).

estimate of avoided outage days as a result of pulling forward two projects that would require a dual unit outage was conservative.[182]

A court cannot rely on speculation in making key findings in support of its ruling,[183] and the OAG has only offered 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.[184] Those 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. The Commission Should Consider PINGP's Historic Performance In Determining An Appropriate Refund Amount

In determining a just and reasonable outcome in this proceeding, the Commission should also 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.[185] This strong performance was critical to customers in periods of extreme weather, including the 2019 polar vortex, the 2021 Winter Storm Uri, and others.[186] The record demonstrates that over the five year period from 2018

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[182] Ex. Xcel-11 at 8-9 (Bible Rebuttal).
[183] *Mast v. County of Fillmore*, 993 N.W.2d 895, 910 (Minn. App. 2023).
[184] Ex. Xcel-11 at 7-9 (Bible Rebuttal); Ex. DOC-1, Schedule 1 at 2 (Golden Direct).
[185] Ex. Xcel-1 at 12 (Krug Direct).
[186] Ex. Xcel-1 at 4 (Krug Direct); Ex. Xcel-4 at 21 (Detmer Direct).

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.[187]

The Company acknowledges 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.[188] However, it did not exceed that average by 100 percent.[189] The industry also experienced outages at that time and 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.[190] This results in a recommended "historic performance" adjustment of 51 percent, to be applied to any net refund amount.[191]

E. A Refund Of $7.4 Million, Plus Interest, Reasonably Reflects The Net Impact On Customers From The PINGP Outage

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

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[187] Ex. Xcel-1 at 4-5 (Krug Direct); Ex. Xcel-3 at 7 (Kurg Rebuttal); Ex. Xcel-4 at 21-22 (Detmer Direct).
[188] Ex. Xcel-1 at 13 (Krug Direct); Ex. Xcel-3 at 7-8 (Krug Rebuttal).
[189] Ex. Xcel-1 at 13 (Krug Direct) ; Ex. Xcel-3 at 7-8 (Krug Rebuttal).
[190] Ex. Xcel-1 at 13 (Krug Direct); Ex. Xcel-3 at 7-8 (Krug Rebuttal); Ex. Xcel-4 at 24 (Detmer Direct).
[191] Ex. Xcel-4 at 24 (Detmer Direct).

replacement energy costs ($34.3 million)[192] and then recognizing 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[193] and $ 21.0 million for the avoided extended outage)[194] and considering the customer benefit of Xcel Energy’s superior operation of the plant for years prior to the Event, by applying a historic performance adjustment.[195] After this full consideration of the costs, offsets and benefits, the Company recommends that the Commission require a refund to customers of $7.4 million, plus interest at the prime rate.[196]

CONCLUSION

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.

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

[193] Ex. Xcel-3 at 6 (Krug Rebuttal); Ex. DOC-1 at 13 (Golden Direct); Tr. at 53 (Detmer).

[194] Ex. Xcel-6 at 18 (Detmer Errata).

[195] Ex. Xcel-3 at 9 (Krug Rebuttal).

[196] Ex. Xcel-3 at 9 (Krug Rebuttal). The Company notes that application of the methodology set forth in Company witness Mr. Detmer’s Direct Testimony (Ex. Xcel-6 at 24 (Detmer Errata)) and adjustment by the Company’s agreement with the Department regarding the value of the “supplemental” or “pulled-forward” work results in a refund of $6.5 million. However, as the Company stated the refund amount as $7.4 million in Rebuttal Testimony, and to not confuse the issue at this late date, the Company’s continues to support a refund of $7.4 million as a just and reasonable result.

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WINTHROP & WEINSTINE, P.A.

By: */s/ Eric F. Swanson*
Eric F. Swanson, #0188128
Elizabeth H. Schmiesing, #0229258
Christopher J. Cerny, #0403524

225 South Sixth Street, Suite 3500
Minneapolis, Minnesota 55402
(612) 604-6400

Lauren Steinhauser
NORTHERN STATES POWER COMPANY,
d/b/a XCEL ENERGY
414 Nicollet Mall
Minneapolis, Minnesota 55401

ATTORNEYS FOR XCEL ENERGY

41194759v2