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Rebuttal Testimony and Schedules
Carl R. Bible

BEFORE THE COURT OF ADMINISTRATIVE HEARINGS
FOR THE
MINNESOTA PUBLIC UTILITIES COMMISSION
STATE OF MINNESOTA

IN THE MATTER OF XCEL ENERGY'S PETITION FOR APPROVAL OF ITS 2023 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES	MPUC Docket No. E002/AA-22-179 CAH Docket No. 21-2500-40336

REBUTTAL TESTIMONY OF

CARL R. BIBLE

On Behalf of

NORTHERN STATES POWER COMPANY

August 13, 2025

Exhibit___(CRB-2)

Cable Failure and Customer Benefits

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Table of Contents

Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Carl Bible. I am employed by Enercon as an Electrical Consultant and am providing Rebuttal Testimony on behalf of Northern States Power Company – Minnesota, d/b/a Xcel Energy (Xcel Energy or the Company).

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS PROCEEDING?

A. Yes. I provided Direct Testimony in this matter on the topics of Cable Failure and Customer Benefit. In that testimony, I concluded that (1) there was a high probability that the direct buried section of the DC control cables would have failed during future plant operation if not discovered during the horizontal boring activity; (2) that upon discovering the condition of the cables, replacement, rather than repair, was best industry practice; (3) the outage times experienced to replace the cables were appropriate based on the scope of work and the testing required to ensure correct equipment operation; (4) Xcel Energy took advantage of the required outage time for the cable replacements to perform additional work that maximized the benefit to the plant, the Company, and its customers; (5) the Company's estimated outage times had the control cables not been replaced and then failed during operation are reasonable; and (6) the Prairie Island Nuclear Generating Plant's (PINGP) strong performance history has provided substantial benefits to Xcel Energy's customers.

Q. DID ANY INTERVENORS PROVIDE DIRECT TESTIMONY REGARDING THOSE TOPICS OR ANY OF YOUR CONCLUSIONS?

A. Yes. The Department of Commerce (Department) and Office of Attorney General (OAG) both provided Direct Testimony on issues raised in my Direct Testimony. Department witness Andrew Golden questioned whether the Company would have acted prudently if it had waited for the cables to fail before replacing them, as posited in scenarios 2 and 3 described at pp. 4-5 of Schedule 2 to my Direct Testimony, and OAG witness Shoua Lee similarly suggested that the Company would need to demonstrate prudence with respect to a repair or replacement occurring after a cable failure. OAG witness Lee also questioned the Company's claim that replacing the cable in 2029 would have led to additional outage days for that planned outage, and questioned both the Company's determination that the pulled forward work that was completed during the 2023 outage saved outage days in the future and the number of outage days that would have been saved.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My Rebuttal Testimony responds to these issues raised by the Department and the OAG.

Q. HOW IS YOUR REBUTTAL TESTIMONY ORGANIZED?

A. My Rebuttal Testimony is organized to address each point raised by subject.

II. RESPONSE TO INTERVENOR DIRECT TESTIMONY

Q. PLEASE SUMMARIZE THE INTERVENOR TESTIMONY SUGGESTING THAT THE COMPANY MAY BE ACTING IMPRUDENTLY BY NOT REPLACING CABLES PRIOR TO CABLE FAILURE, AS DISCUSSED IN YOUR SCENARIOS 2 AND 3.

A. The intervenor testimony suggests that if the Company did not replace the cables until they failed, as posited in scenarios 2 and 3 in my Direct Testimony, it may have acted imprudently. Department witness Golden notes that "given the age and degradation of the cable, it is not clear that it would be prudent to wait until a cable failure to replace it." OAG witness Lee stated, "Xcel has not shown that it was prudent for the Company not to already have inspected and replaced a 50-year-old control cable buried in direct contact with the soil." Both witnesses contend that a lack of prudence here would disqualify these scenarios from consideration as reasonable comparisons to the actual power replacement costs incurred due to the event. Both witnesses contend that the Company should not be able to recover replacement power costs for an outage associated with cable failure due to natural degradation due to aging.

Q. HOW DO YOU RESPOND TO THIS TESTIMONY?

A. The two scenarios at issue involve the hypothetical failure of the control cables as the result of degradation over time. Had the cables failed as a result of aging, it would not have been the fault of the Company, and a finding of imprudence would not be warranted for several reasons.

First, as I understand it, scenarios 2 and 3 from my Direct Testimony were not used as the basis of the Company's recommendation in this case. Rather, the Company utilized scenario 1 to calculate its overall recommendation. Second, I disagree with the suggestion by the Department and the OAG that a future failure of the cables, as was assumed in scenarios 2 and 3, would demonstrate that the Company acted imprudently with respect to those cables. I discuss these reasons below.

First, it is important to note that in the early 1970s, when the cables were installed, it was industry standard to install cables in direct contact with the soil. As a result, there was nothing imprudent about the Company's decision to do the same in connection with the installation of the cables.

Second, once installed and placed in service, the DC control cables were subject to natural processes that could neither reasonably have been prevented nor predicted by the Company. There were no actions by the Company which would have adversely contributed to the condition of the DC control cables prior to October 29, 2023, which would be one of two logical circumstances when one could find fault with the Company's actions. Nor is there evidence of any abnormal condition that would have prompted the need for a special inspection of the cables. There was no history of cable failures at PINGP, no water ponding occurring in the area which would cause degradation, and equipment connected to these cables was operating as expected. Put simply, the degraded condition of these low voltage cables was unexpected.

Third, as noted in my Direct Testimony, there are no industry or Nuclear Regulatory Commission (NRC) standards for inspection and management of the control cables that were impacted. As a result, there are no actions with respect to the cables that the Company failed to take, which would be the only other circumstance when one could find fault with a similarly situated operator's actions. As discussed in Company witness Hiser's Direct Testimony, adequate aging management activities (e.g., inspection, testing) are determined by the NRC as part of the license renewal (LR) and subsequent license renewal (SLR)

processes. Company witness Hiser's Rebuttal Testimony addresses this aspect of OAG witness Lee's testimony as well.

Q. WHAT DID OAG WITNESS LEE CONTEND WITH RESPECT TO THE COMPANY'S CLAIM THAT THE 2029 OUTAGE WOULD HAVE BEEN EXTENDED BY 93 OUTAGE DAYS IF THE COMPANY HAD DECIDED TO REPLACE THE CABLES DURING A PLANNED 2029 OUTAGE?

A. OAG witness Lee argues that in order for the Commission to consider this avoided extension as an offset, it "would have to assume that the 2029 cable replacement could not be done concurrently with other work during another planned outage." She also asserted that Xcel Energy "fail[ed] to account for the possibility of concurrent work …"

Q. HOW DO YOU RESPOND?

A. I disagree with OAG witness Lee's contention in a number of respects. Specifically, a determination that the outage would be extended as a result of the control cable work does not require an assumption that the 2029 cable replacement "could not be done concurrently with other work." The Company did account for the potential to complete work concurrently, as I discuss in greater detail below.

I note that OAG witness Lee acknowledges that she is not an engineer, and she then contends that the question of which work could be performed concurrently is a "non-engineering" issue. There is no question that the appropriateness of concurrent work during an outage *is* an engineering question. I respond to her arguments below.

The concept of "critical path" versus "non-critical path" work is helpful in understanding the flow and duration of any outage. Critical path work is the work that takes the longest, and at a nuclear facility, it is work 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. Here, the critical path work was the cable replacement, which required a dual unit shutdown and needed to be completed in a particular sequence.

In my Direct Testimony, I discussed a scenario (Scenario 1) where Unit 2 is in a planned refueling outage and Unit 1 is removed from service. A timeline for this scenario was submitted in the Company's response to DOC Information Request (IR) No. 49, Attachment B.[1] All cells shown in blue on page 1 of 2 of Attachment B show the cable replacement activities. These activities must be done in a sequential order. This timeline shows final installation of cables and ties to plant equipment to be 20 days. Certain non-critical path work (i.e., work that does not drive the length of the outage), such as some cable trenching could be performed prior to these 20 days (in fact some can be done while the units are online). Additionally, six days of defueled work activities (purple cell on page 1 of the Attachment B diagram) is done concurrently with the 20 days of trenching and final tie in. This is accounted for in the timeline. The same timeline also shows that, after cable installation, 25 days are required for extensive testing and startup.

[1] The Company's response to DOC IR No. 49 is attached to Bible Rebuttal Testimony as Exhibit___(CRB-2), Schedule 1.

As shown in Schedule 1, due to the risk of equipment malfunction during final cable tie-ins and testing, only those activities related to the installation of the cables that are not considered critical path (activities that do not have to be done in sequential order and do not drive outage duration) can be performed during refueling. Unit 2 therefore has a total of 45 days of additional outage time. Unit 1 would have the same 45 days for installation of the cables, testing and startup, plus an additional 3 days for shutdown of the reactor for a total of 48 days. All days of the Unit 1 outage would be considered additional outage days because this unit is not in a scheduled refueling outage. In my professional engineering opinion, the times allocated for these activities are reasonable.

Q. DID OAG WITNESS OAG WITNESS LEE EXPRESS ANY CONCERNS REGARDING THE WORK ADDED TO THE OUTAGE (PULLED-FORWARD WORK) DISCUSSED IN YOUR DIRECT TESTIMONY AND THAT OF COMPANY WITNESS NICHOLAS J. DETMER?

A. Yes. OAG witness Lee testified that, in her opinion, "the Company has not established that pull-forward work conducted during the October 2023 outage could not have been conducted during future planned outages without lengthening that future outage period."

Q. HOW DO YOU RESPOND TO OAG WITNESS LEE'S CONTENTION ON THIS POINT?

A. OAG witness Lee is incorrect. As set forth in the Company's revised Supplemental response to DOC IR No. 35, Attachment B,[2] the work pulled forward into the October 2023 outage included two projects that required dual

[2] The Company's Supplemental response to DOC IR No. 35 is attached to Bible Rebuttal Testimony as Exhibit___(CRB-2), Schedule 2.

unit outages (the cooling water system pipe replacement, denoted in Attachment B as "replace elbow above CR-5-1" and plant screenhouse stop rail guide inspection (denoted in Attachment B as "Inspect CT Stop Log Rail Guides"). Although the stop rail guide inspection was originally scheduled to be performed online, I understand that the Company determined that the rail guide inspection had to be done with both units shut down). These projects would have therefore otherwise required the operating unit not in a refueling outage to be shut down during the other unit's planned refueling outage. Pulling forward this critical work avoided the non-refueling operating unit shutdown outage days. This is not just my expert opinion. It is an undeniable fact.

Q. DID OAG WITNESS LEE EXPRESS ANY OTHER ISSUE WITH THE CALCULATION OF SAVINGS TO CUSTOMERS FROM PULLING FORWARD WORK INTO THE OCTOBER 2023 OUTAGE?

A. Yes. She contends that using 1,050 labor hours per outage day to calculate avoided outage days is arbitrary, but she also notes that this number was based on actual data related to the October 2023 outage.

Q. HOW DO YOU RESPOND TO THIS POINT?

A. I don't agree that using actual labor hours from an actual outage is "arbitrary" It is possible to utilize different assumptions for the daily outage labor hours and arrive at less avoided outage time, as OAG witness Lee suggests. However, the outages cited in OAG witness Lee's testimony that had higher labor hours per day were all single-unit outages, not dual-unit outages. Actual dual unit outage unit data was used to calculate this estimate. And as previously discussed, the cable repair activities require a dual unit outage. This estimate is therefore

very conservative as these work activities require shutting down a non-refueling unit, and the additional days required to shut down and restart the reactor are not included in the 2.2 days.

III. CONCLUSION

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

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Xcel Energy		Information Request No.	49
Docket No.:	E002/AA-22-179		
Response To:	Minnesota Department of Commerce		
Requestor:	Andrew Golden		
Date Received:	June 6, 2025		

Question:

Topic: Outage Time and Replacement Power Cost Estimation during Subsequent License Renewal

Reference(s): Detmer Direct at 18; Exhibit___(NJD-1), Schedule 2 at 2-4

Witness Detmer at page 18 and Exhibit___(NJD-1), Schedule 2 at page 2 of his Testimony estimates the Company avoided a total of 93 days of outage time replacing the cables following the cable failure rather than as part of its 2029 subsequent license renewal (SLR) "using certain simplifying assumptions." Exhibit___(NJD-1), Schedule 2 at 4 also states the PLEXOS model estimated 87 avoided future outage days.

- Please confirm and support whether the Company's avoided replacement power costs were calculated using the 93 or 87 avoided future outage days.
- Please provide additional detail of the quantification of estimated future outage days avoided, such as a timeline of potential cable replacement in 2029 compared to actual cable replacement duration, to better understand the calculation of the estimate and how the assumptions informed it.
- Please provide all inputs and assumptions used in this calculation, as well as any relevant spreadsheets with formulas included, and explain for each one, why they are reasonable.
- Please provide support for the jurisdictional allocator used and why it is reasonable in determining $26.5 million total company amount compared to the $20.5 million Minnesota jurisdictional amount.

Response:

A) The Company's avoided outage days for Case 1 is 93 days. The "87 avoided future outage days" and associated Unit 1 and Unit 2 outage days referenced for Case 1 in the above-referenced schedule was inadvertently incorrect, resulting in an incorrect calculation of the replacement power costs. The Company will submit errata testimony correcting this error.

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B & C) Please see Attachment B to this response. The first tab titled "Flow Chart" was originally developed to help depict the avoided future outage days for a planned cable replacement outage. The flow chart and ultimate avoided outage days calculation relies on best case scenarios. This means it relies on typical refueling outage activity durations for shutdown, defueling, refueling, and startup and assumes no equipment or other issues. As shown by the purple cells in the "Flow Chart" tab, a 27-day refueling outage was assumed as the basis for the planned outage, and the refueling days were not included in the avoided outage days estimate. The second tab, "Calc & Assumptions," provides a comparison of the actual duration of the 2023 outage compared to the estimated durations applied for this planned outage scenario, including the assumptions applied to support the reasonableness of the estimated durations.

D) Please see Attachment A to this response for the supporting documentation for the allocator used. As can be seen in Attachment A, the allocator is based on forecasted sales for the NSP system in 2029. Fuel clause costs have historically been allocated to each state using sales, so this allocator is consistent with that historical treatment.

Attachment A is marked "Not-Public" in its entirety as it comprises information the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). The information contains confidential forecast data that derives an independent economic value from not being generally known or readily ascertainable by others who could obtain economic value or a financial advantage from its disclosure or use. The Company takes efforts to protect this information from public disclosure. Thus, Xcel Energy excises this information as protected data pursuant to Minn. Rule 7829.0500

1. **Nature of the Material**: Long-range Sales Forecast
2. **Authors**: John Goodenough, Xcel Energy
3. **Importance**: Contains not-public, proprietary information.
4. **Date the Information was Prepared**: January 31, 2025 for the allocator and July 14, 2024 for the Sales Forecast

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Witness:	Nicholas J. Detmer	
Preparer:	Amanda J. Jepson	Nick Paluck
Title:	Manager, Nuclear Regulatory Policy	Manager, Regulatory Analysis
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Date:	June 18, 2025	

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Attachment A is marked "Not-Public" in its entirety as it comprises information the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). The information contains confidential forecast data that derives an independent economic value from not being generally known or readily ascertainable by others who could obtain economic value or a financial advantage from its disclosure or use. The Company takes efforts to protect this information from public disclosure. Thus, Xcel Energy excises this information as protected data pursuant to Minn. Rule 7829.0500

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Case 1 Planned Dual Unit Outage: Unit 2 Refueling Outage with DC Cable Replacement

U2: TOTAL TIME OFFLINE (72 days)

U2 TOTAL TIME NO FUEL IN CORE: 51 Days = U2 DC Cable Outage Days: 45 days* + **U2 Refueling Outage Days: 6 days**

U2: Reactor Shutdown, disassembly, core offload (7 days)

U2: Plant System Align, Electrical Alignment (3 days)

U2: Planned Defueled Work without DC cable impact (6 days)

U1/U2: U1 Reactor Shutdown, Cooldown, Alignments (3 days)

U1/U2: Alignment/Isolation of Xfmrs & Switchyard + Final Trenching and Plant Tie-In for DC Cables **(20 days)**

U1/U2: Cooling Tower Xfmr DC Cable Testing (1 day)

U1/U2: 1 Reserve Xfmr DC cable testing (4 days)

U1/U2: U1 Generator Output Breaker Testing (5 days)

U1/U2: 2Reserve Xfmr DC cable testing and xfmr restoration (4 days)

U1/U2: U2 Output Breaker testing (5 days)

U1/U2: U1 Heatup/Startup, Testing, ONLINE (6 days)

U2: Core Reload, Plant Startup/ONLINE (14 days)

U1: TOTAL TIME OFFLINE (48 days)

Notes:
- This graph depicts the main activity driving outage time; it does not depict all the details associated with a refueling/planned maintenance outage
- Purple blocks denote work that would need to be done during a refueling outage and are not counted towards avoided future outage days.
- Blue blocks denote required cable replacement work (Xfmr = Transformer)

*Unit 2 avoided outage days determined by full cable poject scope impacting U2 (51 days) minus overlapping defueled work activities (6 days)

Avoided Outage Days
Unit 1: 48 days
Unit 2: 45 days
Total: 48 + 45 = 93

	Actual Days (unplanned cable replacement)	Estimated Days (planned cable replacement)	Assumptions and Reasonableness
Total Dual Unit Impact	248.5	**93**	Total Estimated Outage Days Avoided, corresponding to breakdown below:
Unit 2 Refueling Outage + Cable Replacement	147.5	72	Actual Days (Column B) includes additional projects and activities that would be done prior to the outage if planned, and are not included in column C. Estimated Days (Column C) assumes best case for typical refueling outage activities with no major equipment issues.
Reactor Shutdown and Core Offload	7	7	This is required for refueling regardless of necessary outage work and not included in avoided outage days (see purple cells in "Flow Chart" tab)
Planned Defueled Work without DC Cable Impact	57.5	6	6 days are required for refueling regardless of other outage work and is not included in avoided outage days (see purple cells in "Flow Chart" tab). Column B included additional projects and activities. Column C represents a best case scenario with no additional projects and activities and no equipment issues.
DC Cable Replacement Impact	57	**45**	See flowchart for assumptions.
Core reload, plant startup/online	26	14	This work is required for refueling regardless of necessary outage work and not included in avoided outage days (see purple cells in "Flow Chart" tab).
Unit 1 Outage for Cable Replacement	101	**48**	The entire Unit 1 shutdown is driven by cable replacement and testing activities. The estimated duration (Column C) assumes best case, no major projects or equipment issues and the assumptions listed below.
Reactor Shutdown, Cooldown, alignments	14	3	The Column B actuals included other activities such as troubleshooting and project design and planning, which happened during the outage because it was unplanned. For a planned outage, this would all be done prior to the outage and therefore those other activities are not included in Column C, which represents the minimum required time for shutdown and cooldown.
Alignment/Isolation of Transformers & Switchyard + Final trenching and plant tie-in for DC cables	45	20	In Column B actuals, 100 percent of the trenching activities for the 2023 cable replacement were undertaken during the outage. Because Column C represents a planned outage, it assumes reduced trenching activities during the outage because a portion of it could be done prior to the outage.
Test setup and prep activities	6	0	Column B shows the actual 6 days for work plan development and reviews prior to each of the below tests being performed. Column C assumes this work would be completed online prior to the outage and would therefore not impact outage duration.
Cooling Tower Transformer DC Cable Testing	1	1	Column B shows the duration required for the work performed. Since no unusual circumstances were encountered that lengthened the time required, Column 6 assumes this same duration.
1 Reserve Tranformer DC Cable Testing	4	4	Column B shows the duration required for the work performed. Since no unusual circumstances were encountered that lengthened the time required, Column 6 assumes this same duration.
U1 Generator Output Breaker Testing	5	5	Column B shows the duration required for the work performed. Since no unusual circumstances were encountered that lengthened the time required, Column 6 assumes this same duration.
2 Reserve Xfmr DC Cable Testing and Xfmr Restoration	4	4	Column B shows the duration required for the work performed. Since no unusual circumstances were encountered that lengthened the time required, Column 6 assumes this same duration.
U2 Output Breaker Testing	5	5	Column B shows the duration required for the work performed. Since no unusual circumstances were encountered that lengthened the time required, Column 6 assumes this same duration.
U1 Heatup/Startup, Testing, ONLINE	17	6	Column B actuals include the impact of certain feedwater equipment issues. Column C reflects a best case scenario with no equipment issues. Feedwater equipment issues impacted actuals.

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Revised Supplement

Xcel Energy		Information Request No.	35
Docket No.:	E002/AA-22-179		
Response To:	Minnesota Department of Commerce		
Requestor:	Katherine Arnold		
Date Received:	October 1, 2024		

Question:
Topic: Calculation of Ratepayer Refund
Reference(s):

State the amount of the refund that you believe Xcel Energy's ratepayers should receive as a result of Xcel Energy's imprudence that resulted in the outages of Prairie Island One and: a) explain in detail your calculation; 2) produce each document that either supports or refutes your calculation. Please include both Total Company and Minnesota Jurisdictional amounts, including support for allocator used.

Response:
The Company objects to this request on the grounds that it is premature and overly burdensome. In particular, this request relates to the contested case ordered by the Commission at the hearing on September 19, 2024 in Docket No. E002/AA-22-179. We do not yet have an order from the Administrative Law Judge (ALJ) related to the discovery procedure or schedule for this case; we will provide responsive, non-privileged documents in response to discovery requested consistent with the schedule and procedures established by the ALJ.

Revision
On June 27, 2025, the Company filed with the Minnesota Public Utilities Commission errata to the Direct Testimony and Schedule 2 of Company witness Nicholas J. Detmer, including a corrected Schedule 2. Since Schedule 2 is the Company's supplemental response to DOC IR No. 35, this revision includes the same corrections provided in the June 27 errata and is provided for completeness. Corrections are made and highlighted in the below response. In addition, we provide live versions of revised Attachments A and C to this response with the cells on page 1 (Tab "PI Summary") of Attachment A and Attachment C marked to indicate the changes. We note that data in the remaining tabs of Attachment A also changed, but it is not possible to mark each of the changes to the hourly data produced in those tabs.

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Revised Supplemental Response
The Company maintains its initial objections to this request. The Company further objects to this request to the extent it assumes imprudence, which the Company continues to dispute.

Without waiving any objections, the Company states that a customer refund, if any, should account for a number of considerations, described in more detail below.

A. Refund Considerations

First, a customer refund, if any, must account for the benefits customers received from the steps the Company took to avoid future outages that would result in customers paying for replacement power costs in the future. These steps include:

Replacing rather than repairing the DC cables. The affected direct current (DC) control cables include 30 cables of 5 shielded twisted conductor pairs each, approximately 1,300 feet long. The cables are direct buried from the substation to the plant in a common trench and are terminated in common locations. The cables supply control power to assets required to operate both units of Prairie Island at power. These assets include transformers supplying offsite power to the plant as well as output breakers for both main electrical generators to supply generated power to the grid.

Upon investigating the event, the Company discovered that the damaged control cables were aging (about 50 years old) and at risk of additional water intrusion as evident by green discoloration of the copper conductor and jacket embrittlement. Eventually, this degradation would have led to one of two outcomes: (1) in the course of the Prairie Island Nuclear Plant Subsequent License Renewal process, the plant would be required to undertake cable aging management inspections and testing, which would likely have revealed the need for replacement; or, (2) a need to replace the cables would be recognized after cable failure, indicated by an increasing number of ground faults over time, causing electrical anomalies in performance of various plant equipment, such as loss of transformers or the generator output breakers, either of which would result in a trip of the units. As a result of either (1) or (2), the DC cables would have had to be replaced at a future date. By fully replacing the DC cables during the 2023 outage, the Company avoided future outage days. We have estimated the impact of each of these scenarios below.

Cable Replacement after Licensing Inspections. If we performed an inspection of the DC cables as part of the Subsequent License Renewal process and, assuming

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that as a result of that inspection, we identified the need to replace the cables, the Company would plan a dual-unit outage for the cable replacement. As indicated above, these cables connected to systems across both units, and these cable bundles were twisted together, coming into the same multi-unit terminal box, resulting in cable components serving both units being in close proximity to one another. Due to the complexity of the cable location and the plant assets the cables support, this would have required a planned dual-unit outage. We would plan the dual-unit outage to coincide with a planned refueling outage for one unit.

The alternative to a dual-unit outage—planning two, single-unit outages—would create a high risk of tripping the online unit during replacement of the offline unit's cables and increase overall outage time. An attempt to separate the cable bundles would likely result in a reactor trip of the other online unit, either due to damage of surrounding conductors or due to the fact that these cable bundles are twisted together and come into the same multi-unit terminal box. The close proximity of cables from each unit also creates the risk of incorrectly disconnecting and reconnecting the wires. These risks are eliminated by performing the cable replacement with both units offline.

In order to determine avoided outage days for a future dual-unit outage to replace the cables, the Company determined that the replacement would be executed the same way it was executed during the 2023 dual-unit outage, excluding those activities that could be performed in advance of the outage. The following assumptions were made:

1) While 100 percent of the trenching activities for the 2023 cable replacement were undertaken during the outage, we assumed the avoided future outage would include reduced trenching activities, accounting only for those portions that require the units to be offline: a section going into the substation and a section going to the plant boundary.
2) While all the cable was laid during the 2023 outage, we assumed that cable would be partially laid prior to the avoided future outage.
3) We assumed that the avoided future outage would take place in conjunction with a typical refueling outage on one of the units, planned for approximately 27 days without major work scope other than the cable replacement project. We removed the refueling work window and associated outage days from the total avoided future outage days. In other words, the Company's total avoided future outage days include only the days required *beyond* refueling to perform the cable replacement.

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After removing overlapping defueled work on Unit 2, the avoided future outage days for Unit 2 is 45 days and for Unit 1, 48 days. Total avoided future outage days for both units is therefore 93 days.

To quantify the avoided replacement power costs for those days, the Company assumed an outage in 2029 when Unit 2 is scheduled for refueling and utilized PLEXOS to evaluate the avoided costs. As shown in the data identified by Case 1 on the "PI Summary" tab of Attachment A to this response, the PLEXOS model assumed an additional 45 days of outage at Unit 2 and 48 days at Unit 1 for a total of 93 avoided future outage days. The avoided replacement power costs had the Company needed to perform this work in 2029 are estimated to be **[PROTECTED DATA BEGINS PROTECTED DATA ENDS].**

Cable Replacement after Cable Failure. As discussed above, if the Company did not discover the need to replace the cables through an inspection, cable failure would have eventually resulted in a forced outage of one or both units. If one of the units was in a planned refueling outage (i.e., already shut down) at the time the online unit tripped, such as what occurred in 2023, then avoided outage days would be equivalent to the entire tripped-unit forced outage duration, plus the additional outage days incurred on the unit already shutdown for refueling. In the case of the 2023 planned Unit 2 refueling outage, 63 days were planned for refueling and baffle and clevis bolt replacements. A typical refueling outage without major scheduled projects would be scheduled for about 27 days. This includes 7 days up front to shut down and remove fuel from the core, 6 defueled outage activity days, and 14 days to refuel the reactor, complete required testing, and start up. Using the 2023 outage data, Unit 1 was the online unit that tripped and resulted in a 101-day outage (October 19, 2023 – January 27, 2024). See the Company's response to DOC IR No. 22. The 2023 outage included investigation, project planning, and execution, and we would expect the same required activities if this happened in the future. Therefore, in an avoided future forced outage, we would anticipate the same 101-day duration for the tripped unit (Unit 1 in this scenario). These 101 days would limit the duration of the avoided future outage; in other words, the refueling unit could not be started up until after the tripped unit is brought online due to refueling-outage-specific startup testing required on the refueling unit. To determine avoided outage days on the refueling unit (Unit 2), the planned defueled 6 day window on the refueling unit could be subtracted from the 101 (this is work that would have to be performed regardless of the cable being replaced), resulting in 95-avoided outage days on Unit 2. Combining avoided outage days for both units, a total of 196 future outage days were avoided.

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Using the PLEXOS model, and as shown with the data related to Case 3 in the "PI Summary" tab of Attachment A, the replacement power costs had the Company needed to perform this work in 2029 are estimated to be **[PROTECTED DATA BEGINS PROTECTED DATA ENDS].**

Alternatively, cable failure could result in a dual-unit reactor trip, i.e., neither unit is in refueling and both units trip. In this scenario, avoided outage days could again be determined using the data from the 2023 outage and applying the duration of the Unit 1 cable replacement outage to *both* units. Again, the Unit 1 outage was 101 days. In addition, 6 days are added for Unit 2 start-up activities after Unit 1 is online, bringing the Unit 2 outage duration to a total of 107 days. Taken together, in this scenario, a total of 208 future outage days were avoided. Using the PLEXOS model, and as shown with the data related to Case 2 in the "PI Summary" tab of Attachment A, the replacement power costs had the Company needed to perform this work in 2029 are estimated to be **[PROTECTED DATA BEGINS PROTECTED DATA ENDS].**

If the cable began to fail intermittently (or gradually fail) as could be evident in electrical grounding and various equipment alarms or relays and breakers opening, there is potential that cable troubleshooting activities could identify the need for cable replacement and a future dual-unit outage could be planned. This would result in the same modeling as "cable replacement after licensing inspections" as previously described.

Using the period in which the plant was offline to pull forward and perform work that was already scheduled for a future outage. As shown in Attachment B to this response, the Company completed various projects during the 2023-2024 outage that were scheduled to be completed during future outages. Based on labor hours, the work performed on these pulled-forward projects correlates to the equivalent of approximately 8.1 avoided future outage days. Using the results from the planned outage case above (Case 1), an estimate was made by dividing the **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** by 93 days to derive a daily rate of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** per day and multiplying by 8.1 days for avoided replacement power costs of this pulled-forward work of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS].**

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Second, a refund to customers, if any, should consider the benefits customers have received from the Company's historical performance of the plant compared to other industry participants. As seen in Attachment A to the Company's July 30, 2024 Reply Comments in this docket, the Company's overall performance from 2018 through 2023, was superior to median industry performance. For example, as supported by that prior Attachment A, the financial benefit of the Company's superior performance from 2018-2023 to our customers can be quantified by comparing the MWh generated during this time period to what we forecasted for unit performance, based on reasonable expectations for performance. Based on this comparison, the Company estimates that from 2018 through 2022, it generated approximately 2,577 GWh above our forecasted amount, resulting in estimated benefits to customers of approximately $50.6 million compared to normal operating performance. *See* July 30, 2024 Reply Comments.

If there are additional considerations that the Company determines could impact a customer refund, it will present those considerations in its testimony on this issue.

B. Refund Calculation

Taken together, the Company's offset calculations are provided in Attachment C to this response. Taking the PLEXOS model calculation of replacement costs provided in Attachment 1 to the Company's second supplemental response to DOC IR No. 30, assuming a jurisdictional allocation in 2029 of 77.3 percent based on forecasted sales, and applying the most conservative case for avoided outage days, Case 1, less the avoided costs for the additional pulled-forward work during the outage in 2023 and 2024, results in offsets that would lower any proposed customer refund to approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. This, however, does not account for the Company's superior historical performance, which provides further mitigating factors that the Company may account for as the case proceeds. For example, adjusting the refund to account for the amount of time the units were out compared to industry-median performance for the five-year period from 2018-2023 (51 percent), as opposed to the Company's industry-leading performance during that time, would further reduce any proposed customer refund to approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS].**

As mentioned above, if there are additional considerations that the Company determines could impact a customer refund, it will present them in its testimony on this issue, including their impact on any refund.

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Please note that this response as well as all of Attachment A and portions of Attachment C are marked as "Not Public" as they contain information the Company considers to be "not-public data" pursuant to Minn. Stat. §13.02, Subd. 9. This is information the Company considers to be "Trade Secret" information pursuant to Minn. Stat. § 13.37, subd. 1(b), because it has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use.

The live version of Attachment A is marked as "Not-Public in Entirety." Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: The workpapers contain Confidential and Proprietary forecast modeling inputs and outputs from PLEXOS, including contract terms and forecasted market pricing.
2. **Authors:** The data is output from PLEXOS and prepared under the direction of Nick Detmer.
3. **Importance:** The workpapers contain competitively sensitive data.
4. **Date the Information was Prepared**: The information was prepared in June 2024.

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PLEASE NOTE ATTACHMENT A AND ATTACHMENT C ARE BEING FILED AS LIVE EXCEL SPREADSHEETS

22-0179 DOC-035 Revised - Attachment A - TRADE SECRET IN ENTIRETY.xlsx

22-0179 DOC-035 Revised - Attachment C - TRADE SECRET (V2).xlsx

PLEASE NOTE ATTACHMENT A IS TRADE SECRET IN ENTIRETY

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The live version of Attachment A is marked as "Not-Public in Entirety." Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: The workpapers contain Confidential and Proprietary forecast modeling inputs and outputs from PLEXOS, including contract terms and forecasted market pricing.
2. **Authors:** The data is output from PLEXOS and prepared under the direction of Nick Detmer.
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4. **Date the Information was Prepared**: The information was prepared in June 2024.

Northern States Power Company

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Protected Data Is Shaded

Corrected Data is highlighted in yellow and is also Protected Data.

2023-2024 Outage PI Replacement Costs - 'Production Cost Model (PLEXOS) Calculation Method

Total Plant (Prairie Island 1 & 2)

Month	NSP-Minnesota Replacement Power Costs	Minnesota Allocator	Minnesota Replacement Power Costs
	[PROTECTED DATA BEGINS		
Oct-23		71.44%	
Nov-23		70.92%	
Dec-23		70.77%	
Jan-24		70.22%	
Feb-24		70.78%	
Mar-24		70.47%	
	-		

Prairie Island 1

Month	NSP-Minnesota Replacement Power Costs	Minnesota Allocator	Minnesota Replacement Power Costs
Oct-23		71.44%	
Nov-23		70.92%	
Jan-24		70.22%	
Feb-24		70.78%	
Mar-24		70.47%	
	-		

Prairie Island 2

Month	NSP-Minnesota Replacement Power Costs	Minnesota Allocator	Minnesota Replacement Power Costs
Oct-23		71.44%	
Nov-23		70.92%	
Dec-23		70.77%	
Jan-24		70.22%	
Feb-24		70.78%	
Mar-24		70.47%	

PROTECTED DATA ENDS]

Total Plant 2029 Avoided Replacement Power Costs

	NSP	MN Allocator	MN
	[PROTECTED DATA BEGINS		
Case 1		77.30%	
Case 2		77.30%	
Case 3		77.30%	
Pulled Forward		77.30%	

Total Plant Less 2029 Replacement Power Costs

	Case 1	Case 2	Case 3
Pulled Forward			
Industry-median performance			

Unit 1 2029 Avoided Replacement Power Costs

	NSP	MN Allocator	MN
Case 1		77.30%	
Case 2		77.30%	
Case 3		77.30%	
Pulled Forward		77.30%	

Unit 1 Less 2029 Replacement Power Costs

	Case 1	Case 2	Case 3
Pulled Forward			
Industry-median performance			

Unit 2 2029 Avoided Replacement Power Costs

	NSP	MN Allocator	MN
Case 1		77.30%	
Case 2		77.30%	
Case 3		77.30%	
Pulled Forward		77.30%	

Unit 2 Less 2029 Replacement Power Costs

	Case 1	Case 2	Case 3
Pulled Forward			
Industry-median performance			

PROTECTED DATA ENDS]