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

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

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

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

SURREBUTTAL TESTIMONY AND SCHEDULES OF THE OFFICE OF THE MINNESOTA ATTORNEY GENERAL—RESIDENTIAL UTILITIES DIVISION

WITNESS:

SHOUA LEE

September 17, 2025

TABLE OF CONTENTS

I. INTRODUCTION 1

II. SUPPLEMENTAL PULL FORWARD WORK 2

III. AVOIDED 2029 COSTS 7

IV. PERFORMANCE ADJUSTMENT 14

V. SUMMARY OF RECOMMENDATIONS 16

I. INTRODUCTION

Q. Are you the same Shoua Lee that submitted direct testimony in this proceeding?

A. Yes, I submitted direct testimony on behalf of the Residential Utilities Division of the Office of the Minnesota Attorney General (OAG).

Q. Would you briefly summarize your direct testimony?

A. In direct testimony, I recommended that the Minnesota Public Utilities Commission (Commission) reject Xcel's (Company's) three claimed offsets for:

1. supplemental pull-forward projects totaling $1.8 million (MN jurisdiction);
2. avoided 2029 costs totaling $21.0 million (MN jurisdiction); and
3. performance adjustment totaling $5.7 million (MN jurisdiction).

Xcel proposed each of these offsets to reduce the refund that it will be required to pay ratepayers as a result of imprudently cutting through buried control cables at its Prairie Island Nuclear Generating Plant (PINGP).

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond to the Company's rebuttal testimony regarding the recommendations from my direct testimony and the Company's agreement with the Department of Commerce's recommendation that it will accept a lower offset amount than it originally calculated for the "pulled forward" costs.[1]

Q. At a high level, how does the Company respond to your direct testimony?

A. The Company does not accept any of the recommendations from my direct testimony. However, the Company does not provide additional information that resolves my concerns.

[1] Krug Rebuttal at 6.

II. SUPPLEMENTAL PULL FORWARD WORK

Q. What is this offset adjustment for?

A. The Company rescheduled other planned future projects to occur during the outage that was caused by the incident (the October 2023 outage). The Company claims that "pulling forward" this work avoided future outage time without lengthening the October 2023 outage.[2]

Q. What is the amount of the adjustment originally proposed by the Company?

A. The Company stated in direct testimony that pulling forward this work avoided 8.1 future outage days, which reduced the need for future replacement power costs by $1.8 million (MN jurisdiction).

Q. What concerns did you raise about the Company's proposed offset for pull-forward work?

A. My concerns were that (1) the Company failed to establish that it could not have completed the pulled-forward work in future periods without lengthening a future outage period and (2) the Company's assumed labor hours per outage day used to calculate the offset appear to be arbitrary.

Q. What is the Company's position in rebuttal?

A. The Company states that (1) certain work pulled forward into the October 2023 outage (a cooling water system pipe replacement and a plant screenhouse stop rail guide inspection) required both units to be shut down and therefore avoided outage days in a future outage for the unit not being refueled[3] and (2) it attempted to be conservative in its estimates of

[2] Krug Rebuttal at 2.
[3] Bible Rebuttal at 7–8.

avoided future outage time for this "pulled forward" work, and doesn't agree with my concern regarding the arbitrary labor hours used to calculate the number of outage days.[4]

Q. What is your response to the Company's first explanation?

A. Even assuming the two above-noted projects required dual-unit outages, that does not mean that these projects would necessarily have driven future outage days. That would depend on what other work occurred during the future dual-unit outage.

Q. Can you explain further?

A. Yes. My understanding is that these projects would only drive future outage days if they were "critical path." According to Xcel, "whether an item is critical path can depend on the other projects scheduled for the same outage," and "[i]f a future dual unit outage were performed and included other work that was scheduled to take more time to perform than these two activities, then these activities would not be critical path."[5] In other words, these pulled-forward projects would only drive future outage days if no longer-duration work that required both units to be offline occurred during the future outage.

As I stated in my direct testimony, it is unknown whether the pulled-forward projects could be done in parallel with critical-path work in a future outage and, therefore, whether pulling them forward avoided any future outage days. However, we do know that these projects were not critical-path during the October 2023 outage because, according to Xcel, they were done in parallel with the cable replacement work and did not add additional days to the outage.[6] Therefore, I continue to conclude that Xcel has failed to meet its burden to show that pulling forward these projects avoided any future outage days.

[4] Krug Rebuttal at 6–7.
[5] Xcel Response to OAG IR 19(K), attached as Schedule SL-S-1.
[6] Lee Direct Schedule SL-D-2 at 2 (attaching response to OAG IR 9).

Q. Is there additional evidence that the cooling water system pipe replacement would not have driven future outage days had it not been completed during the October 2023 outage?

A. Yes. The Company has identified the "pipe replacement on cooling water system" project as being on the Company's "dual unit forced outage list."[7] This means it was not scheduled for or scoped into a specific future outage but rather "was identified as needing to be added to the next available dual unit outage."[8] In other words, Xcel maintains the dual unit forced outage list for projects that require a dual-unit outage but do not warrant a *planned* dual-unit outage. Instead, Xcel waits to conduct them when other factors cause a forced outage for both units, such as the October 2023 outage.

Absent the October 2023 outage, it is unclear when Xcel would have conducted the pipe replacement project. However, one option would have been during the next dual-unit forced outage. And Xcel acknowledges that, whenever the pipe replacement otherwise occurred, whether the project was critical path at that time would depend on what other work occurred during the outage,[9] just as it did during the October 2023 outage. Given that the cooling water system pipe replacement project was scheduled to be performed when other factors required a dual-unit outage, and we do not know what other work would have occurred during that hypothetical outage, Xcel has failed to establish that "pulling forward" this project avoided future outage days.

[7] Lee Direct Schedule SL-D-2 tbl.1 (attaching response to OAG IR 9).
[8] Xcel Response to OAG IR 19(D), attached as Schedule SL-S-1.
[9] Xcel Response to OAG IR 19(K), attached as Schedule SL-S-1.

Q. Is there other evidence illustrating the uncertainty inherent in predicting how a given pulled-forward project would impact future outages?

A. Yes. The Company originally characterized its "plant screenhouse stop log rail guide inspection" project as possible to complete while the plant was online, but later claimed that the work could only be done during a dual-unit outage.[10] In other words, Xcel appears to have revised its assumptions about whether completing this project would require an outage *at all*. This change calls into question the credibility of Xcel's updated assumption that the project required a dual-unit outage. It also illustrates the uncertainty around predicting how the pulled-forward projects impact future outages, including how long the projects will take, and whether pulling them forward truly saved any future outage days.

Q. Are you opining that pulling forward these projects either did or did not avoid future outage days?

A. No, and I believe the answer to that question is unknowable. Xcel has advanced the pull-forward offset to avoid making ratepayers whole for imprudently causing the October 2023 outage. The Company therefore bears the burden of proving that the pulled-forward projects avoided future outage days. The purpose of my testimony has been to identify Xcel's unproven assumptions to illustrate how the Company has failed to meet its burden. The Company has not addressed my concerns and has not met its burden. Xcel's offset for pulled-forward work depends on the assumption that these projects would have driven the length of a future outage. But if these projects were done during a future outage or outages where both units were shut down, and their durations were shorter than other work being done at the same time, pulling them forward to the October 2023 outage would not avoid

[10] Xcel Response to OAG IR 19(E), attached as Schedule SL-S-1.

future replacement-power costs, and there would be nothing to offset the ratepayer refund with. The Company should not receive any offset since it has not proven whether the pulled-forward work avoided any future outage days.

Q. What is the Company's response to your concerns regarding the labor-hours-per-outage-day assumption it used for the pull-forward offset?

A. The Company argues that its assumption of 1,050 labor hours per outage day is reasonable because it relies on "[a]ctual dual unit outage unit data" from the October 2023 outage and "the cable repair activities require a dual unit outage."[11] The Company asserts that the higher labor-hours-per-outage-day figures that I cited in direct based on historical outages were from single-unit outages. It concludes that its estimate of avoided outage time is "therefore very conservative as these work activities require shutting down a non-refueling unit" and because Xcel did not count "the additional days required to shut down and restart the reactor" in its estimate.[12]

Q. What is your response to the Company?

A. The Company hasn't fully addressed the question of whether the October 2023 outage is the most accurate representation of the future outage days avoided for the pulled forward projects. The Company agrees that "[i]t is possible to utilize different assumptions for the daily outage labor hours and arrive at less avoided outage time."[13] But the Company has not provided an analysis of different dual-unit outages where similar repairs to similar assets were completed to show that the daily labor-hour assumption used to calculate the number of outage days is reasonable and does not unduly favor the Company.

[11] Bible Rebuttal at 8.
[12] *Id.* at 8–9.
[13] *Id.* at 8.

Q. Has the Company revised its requested offset for the pulled forward projects?

A. Yes. The Company states that it "has agreed to the Department's recommendation that the value to customers for the pulled forward work is valued at $500,000 which is based on the revised 2.2 days of avoided future outage time proposed by the Department."[14]

Q. What is your recommendation for the Company's request to receive credit for pulled-forward work to offset the ratepayer refund?

A. For the reasons discussed above, I continue to recommend that the Commission deny any offset based on the Company's unreasonable and unsupported assumptions about how pulling work forward impacts the duration of future outages.

III. AVOIDED 2029 COSTS

Q. What is the "avoided 2029 costs" offset for?

A. The Company is proposing that it receive a credit for "taking the prudent step of replacing [the] control cables following the Event, . . . [which] avoided the need to replace them at a later date and avoided the costs of replacement power that would have been incurred, and passed on to customers, during that future outage."[15]

Q. What is the amount of the adjustment originally proposed by the Company?

A. The Company stated that the credit is based on 93 avoided future outage days in 2029 when it hypothetically would have replaced the control cables during a Nuclear Regulatory Commission (NRC) subsequent license renewal (SLR) process, which equates to $21.0 million (MN jurisdiction) in replacement-power costs that do not have to be incurred for these 93 days.

[14] Krug Rebuttal at 6.
[15] *Id.* at 5.

Q. What concerns did you raise about the Company's proposed offset for avoided 2029 costs?

A. My concerns were that making a determination now for a hypothetical scenario requires many assumptions including (1) a predetermination of prudency at this time for a future event where facts have not been established and (2) that the 2029 work couldn't be done concurrently with other work during a future planned outage such that a hypothetical 2029 replacement would not cause any additional outage days. I also raised a question about the jurisdictional allocators the Company used to calculate the offset.

Q. What is the Company's position in rebuttal?

A. The Company argues that (1) there would be no potential prudency issues in 2029,[16] (2) that "it was prudent for Xcel Energy not to have already inspected and replaced the subject cables,"[17] and (3) that its offset assumes that "cable replacement work could be done at the least disruptive time – when one of the two PINGP units was already in a refueling outage."[18]

Q. What does Company witness Bible claim about the prudence of Xcel's actions with respect to installing and maintaining the control cables?

A. The Company states that (1) it buried the control cables in line with industry standards[19]; (2) the cables once installed "were subject to natural processes that could neither reasonably have been prevented nor predicted by the Company," and Xcel took "no actions . . . which would have adversely contributed to the condition of the DC control cables" nor

[16] *See id.* at 4; Bible Rebuttal at 4.
[17] Hiser Rebuttal at 2.
[18] Krug Rebuttal at 4.
[19] Bible Rebuttal at 4.

is there evidence of "any abnormal condition that would have prompted the need for a special inspection of the cables"[20]; and (3) the NRC has promulgated no standards for inspection and management of the control cables.[21]

Q. What does Company Hiser say about the prudence of not having already inspected and replaced the control cables?

A. The Company argues that the NRC's lack of aging management guidelines for the cables (such as specific testing/inspections) during the 40 to 60 year period of the license renewal (LR) operating term after initial licensing would prevent the Company from being found imprudent for allowing the buried control cable to degrade to the point of failure.[22] The Company further argues that the "only potentially relevant guidance applies for the subsequent license renewal period. PINGP has not yet entered this period, which runs from 60 to 80 years after initial licensure."[23]

Q. What is your response to the Company's rebuttal?

A. The Company's reliance on current NRC standards to conclude that it would not be found imprudent in the future is unreasonable. Any future cable failure or replacement would need to be assessed under the NRC engineering standards and guidelines applicable at that time, and it is impossible to make that assessment now with certainty. Furthermore, as I stated in my direct testimony, there are any number of scenarios under which future replacement of the control cable could happen. We simply cannot know what Xcel's future

[20] *Id.*
[21] *Id.*
[22] Hiser Rebuttal at 2.
[23] *Id.* at 3.

actions would have been in the absence of the Event, which makes establishing the prudence of those actions speculative if not impossible.

Q. Does the Company respond to your question of whether the hypothetical 2029 cable replacement could be done concurrently with other work during another planned outage?

A. Yes. Company Witness Bible states that it "did account for the potential to complete work concurrently"[24] and that "the critical path work was the cable replacement, which required a dual unit shutdown and needed to be completed in a particular sequence."[25]

Q. What is your response?

A. Similar to the pulled-forward projects, the Company assumes without sufficient support that the cable replacement would have been critical-path during a hypothetical 2029 outage. As I discussed earlier, a "critical path" project is simply the project that takes the longest and therefore drives the outage length. That means that the cable-replacement would only be critical-path, and drive 2029 replacement-power costs, if no longer-duration project that required both units to be offline were scheduled for that hypothetical outage. It is simply not possible to predict the future and know with certainty that the cable replacement could not be done concurrently with other, critical-path work that would be required for reliability purposes,[26] as part of the SLR process, or for compliance with new NRC standards or

[24] Bible Rebuttal at 5.
[25] *Id.* at 6.
[26] Docket No. E-002/RP-24-67, Compliance Filing – Planned Investments – Monticello and Prairie Island Nuclear Generating Plants (July 18, 2025) (providing schedule of near-term planned investments).

environmental regulations. Any doubt about this needs to be resolved in ratepayers' favor.[27]

Q. What is your recommendation regarding the avoided 2029 costs offset?

A. I continue to recommend that the Commission deny any offset based on the Company's hypothetical cable-replacement scenarios because it would require the Commission to predetermine prudency for uncertain and speculative future events. Additionally, the Company's assumption that the cable replacement would be the critical-path project in the hypothetical 2029 outage fails to consider the possibility that other projects could overtake the cable replacement as critical-path work. As a result, the Commission is being asked now to make a determination based on uncertain factors relating to hypothetical future events. The Commission should resolve these uncertainties in ratepayers' favor and deny the offset.[28]

Q. Does the Company respond to your question about interjurisdictional allocation of the avoided 2029 replacement-power costs?

A. Yes. The Company states that the "jurisdictional allocators for the 2023 and 2024 replacement power costs were determined as . . . historically done – fuel clause costs such as these are allocated to each state based on sales"[29] and that the higher jurisdictional allocator used in 2029 reflects over 2,000 megawatts of new data-center load that Xcel has projected in its recent integrated resource plan (IRP).[30]

[27] *See* Minn. Stat. §§ 216B.03, .16, subd. 4.
[28] *See* Minn. Stat. §§ 216B.03, .16, subd. 4.
[29] Krug Rebuttal at 5.
[30] *Id.*

Q. Does this information support the use of a higher jurisdictional allocator for 2029?

A. No. Using this higher jurisdictional allocator is not reasonable because it has the effect of decreasing ratepayers' refund based on the Company's forecast for load in 2029 that may or may not come online as anticipated. Xcel notes that its recent IRP projected a significant increase in load to due data centers, but forecasts can change, as the Commission itself recognized in ordering Xcel to file another IRP within 24 months. The Commission stated that "Resource planning can change significantly in a relatively short amount of time, as it did in the present IRP docket with the substantially increased load forecast."[31]

Q. Is the Commission concerned about the Company's load forecast for data centers?

A. Yes. The Commission has concerns about data center load growth in the Company's service area and ordered the Company to "make a filing in a new docket with a proposal for development of a new rate class or sub-class and tariff for super-large customers. . . . Specifically, the proposal must detail what combination of existing and new renewable or thermal energy resources, transmission (both high voltage alternating current and high voltage direct current), demand flexibility from super-large customers, demand response, and energy efficiency resources Xcel will use to serve the super-large class or sub-class. Xcel must also discuss how existing and future electric service agreements will be incorporated into a future rate case."[32] The Commission's concern means that developments around data centers in Xcel's service area, including expectations of future load growth, will likely be closely monitored by the Commission.

[31] Docket No. E-002/RP-24-67, ORDER APPROVING SETTLEMENT AGREEMENT WITH MODIFICATIONS at 19 (Apr. 21, 2025).
[32] *Id.* at 17.

Q. What is your recommendation for the Company's proposed jurisdictional allocator?

A. Using the higher allocator implied by Xcel's 2029 sales forecast would unreasonably resolve uncertainty about future data-center load against ratepayers. Therefore, in the event that the Commission approves the Company's request for an "avoided 2029 cost" offset, I recommend that the jurisdictional allocator used for calculating the offset be based on the weighted average of the Minnesota jurisdictional allocators used by the Company to determine the Minnesota replacement power costs during the October 2023 outage.

Q. What is the weighted average of the Minnesota jurisdictional allocators?

A. The Minnesota jurisdictional allocators used by the Company to determine the 2023–2024 replacement power costs are shown in Witness Detmer's Schedule 2.[33] The weighted average of these would be 70.57% as shown in the table below.

Table 1
Minnesota Jurisdictional Allocator (from Detmer Schedule 2)

Month	Minnesota Allocator	MN Replacement Power Costs	Weighted Ave Minnesota Allocator
Oct 23	71.44%	$2,140,736	.04464
Nov 23	70.92%	$4,994,408	.103388
Dec 23	70.77%	$5,862,582	.121103
Jan 24	70.22%	$16,658,620	.341441
Feb 24	70.78%	$4,475,323	.092459
Mar 24	70.47%	$128,104	.002635
		$34,259,773	**70.57%**

[33] *See* Detmer Public Direct Schedule 2 at 12 of 12.

Q. Should this weighted average jurisdictional allocator also be used to calculate another offset?

A. Yes. In the event that the Commission approves the Company's request for a "pull-forward project" offset, I recommend the Company use the same weighted average jurisdictional allocator to determine the amount of the offset for the Minnesota jurisdiction.[34]

IV. PERFORMANCE ADJUSTMENT

Q. What is the "performance adjustment" offset for?

A. The Company is proposing it receive credit for the alleged strong performance of PINGP over the four years preceding the Event (2018–2022), which it claims "saved Xcel Energy customers millions of dollars in power costs compared to what they would have paid if PINGP had industry-standard operating performance."[35]

Q. What is the amount of the adjustment proposed by the Company?

A. The Company is proposing to offset the ratepayer refund by $5.7 million (MN jurisdiction) for the "performance adjustment." The adjustment reduces the net refund amount by 49 percent to reflect that PINGP's offline hours exceeded the industry median by 51 percent over 2018–2023 (including the October 2023 outage).

Q. What were your concerns about the Company's proposed offset for this performance adjustment?

A. My concerns were that the proposed offset goes against principles of sound regulation and disregards the regulatory compact: ratepayers are already paying the Company for

[34] *See id.*
[35] Krug Rebuttal at 7.

PINGP's depreciation, return, taxes, and other operating expenses throughout its service life in exchange for the Company's prudent operation of PINGP.

Q. What is the Company's position in rebuttal?

A. The Company states that "the 'performance adjustment' holds the Company to an assumption of industry-median performance, not perfection, and recognizes that some level of outage is expected and reasonable."[36]

Q. What is your response to the Company's rebuttal?

A. Nothing in the Company's rebuttal changes my opinion that it is unreasonable to give Xcel "extra credit" for operating PINGP prudently in the past. Xcel has already been well compensated for its prior operation of PINGP, including through a Commission-approved profit margin, or rate of return, designed to compensate shareholders for Xcel's business risks. Because Xcel already receives a return on its investment in PINGP, allowing Xcel to offset the cost of its October 2023 imprudence based on past performance would in effect double-compensate the Company for that performance.

Q. What is your recommendation?

A. I recommend the Commission deny the Company's request for a performance adjustment because it is not consistent with principles of sound regulation and ignores the Company's responsibility to uphold the regulatory compact under which it is expected to prudently operate PINGP.

[36] *Id.* at 8.

V. SUMMARY OF RECOMMENDATIONS

Q. Provide a summary of your recommendations.

A. My recommendations remain the same as in my direct testimony. Specifically, I recommend that the Commission reject Xcel's three claimed offsets for (1) supplemental pull-forward projects, (2) avoided 2029 costs, and (3) the "performance adjustment," which the Company has calculated to be $1.8 million (MN jurisdiction), $21.0 million (MN jurisdiction), and $5.7 million (MN jurisdiction), respectively.[37]

In addition, I recommend that in the event the Commission approves the Company's request for an "avoided 2029 cost" or a "pull-forward project" offset, the Company use the weighted average of the jurisdictional allocators that it used to determine the 2023–2024 replacement power costs, or 70.57%, to determine the amount of these two offsets for the Minnesota jurisdiction.[38]

Q. Does this conclude your surrebuttal testimony?

A. Yes.

[37] Detmer Direct Errata Table 4.
[38] *See* Detmer Public Direct Schedule 2 at 12 of 12.

Table of Contents
Schedules to Surrebuttal Testimony of Shoua Lee
CAH Docket No. 21-2500-40336
MPUC Docket No. E-002/AA-22-179

Schedule	Designation	Description
Schedule 1 (SL-S-1)	Public	OAG Information Request 19

☐ **Highly Confidential Not-Public Document – Not For Public Disclosure**
☐ **Not-Public Document – Not For Public Disclosure**
☐ **Public Document – Highly Confidential & Not-Public Data Has Been Excised**
☒ **Public Document**

Xcel Energy		Information Request No.	19
Docket No.:	E002/AA-22-179		
Response To:	Minnesota Office of the Attorney General		
Requestor:	Peter Scholtz		
Date Received:	August 21, 2025		

Question:

Reference:

- Detmer Public Direct Schedule 2 at 9–10 of 12, listing pulled-forward work orders totaling 8,505 labor hours
- Xcel response to OAG IR 9(C), stating that only certain "critical path" pulled-forward work required a dual-unit shutdown and that this work totaled approximately 2,272 labor hours
- Xcel response to OAG IR 15(C), stating that pulled-forward work requiring a dual-unit shutdown "corresponds specifically to the elbow replacement and another pulled forward project, the plant screenhouse stop log rail guide inspection"
- Xcel response to OAG IR 17(B), stating that "'Pipe replacement on cooling water system' (i.e., the elbow pipe replacement), and 'Plant screenhouse stop log rail guide inspection'" make up the 2,272 labor hours referenced in OAG IR 9(C)
- Xcel response to OAG IR 9, table 2, which reads, in part:

On dual unit forced outage list	Pipe replacement on cooling water system	Yes	1,820 labor hours
Online; Q1 2025 (preference for dual unit outage)	plant screenhouse stop log rail guide inspection	Yes	452 labor hours

A. What is the "dual unit forced outage list?"
B. Provide the dual unit forced outage list that was in place on the date of the event.
C. Confirm that the items on the dual unit forced outage list are not pre-scheduled for particular planned outages. If you cannot confirm this, explain.
D. Confirm that the "pipe replacement on cooling water system (i.e. the elbow pipe replacement)" work was not scheduled to occur on a specific date or

during a specific planned outage before the decision to pull it forward was made. If you cannot confirm this, explain and provide the date the work was scheduled for.

E. Confirm that the "Online" notation used for "plant screenhouse stop log rail guide inspection" item in the screenshot above indicates that the screenhouse stop log rail guide inspection could have been completed while the plant was online. If you cannot confirm this, explain.
F. Explain why there is a "preference for dual unit outage" with respect to the plant screenhouse stop log rail guide inspection.
G. Confirm that a dual unit outage is not required for the plant screenhouse stop log rail guide inspection to be performed. If you cannot confirm this, explain.
H. Define "critical path" as the term is used in the response to OAG IR 9(C).
I. Explain how the "plant screenhouse stop log rail guide inspection" could be considered "critical path" work for an outage if there is a preference, but not a requirement, for the plant to be offline.
J. Provide the critical path projects in the 2023-2024 cable replacement outage. Confirm that the "pipe replacement on cooling water system" and "plant screenhouse stop log rail guide inspection" were not critical path projects. If you cannot confirm this, explain.
K. Confirm that whether the "pipe replacement on cooling water system" and "plant screenhouse stop log rail guide inspection" items would be "critical path" in a future outage depends on what other refueling work or major projects are scheduled to occur during that outage. If you cannot confirm this, explain.

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

Response:

A. "Dual forced outage list" refers to a list of identified maintenance issues that require a dual unit outage to address.

B. The dual unit forced outage list at the time of the event is provided below. Under "Outage #," "2R32" refers to the Unit 2 refueling outage that started in Fall 2023. Under "Current Status," the letters "INIT" indicates the work was at initial planning status. Note that when a work item is identified, it needs to be coded to an outage. Outage 2R32 was not planned to be a dual outage, and this work was not part of the 2R32 outage scope. Rather, this work was coded to the next open outage (i.e., 2R32) so that the plant could begin working on the planning process.

Dual Unit Forced Outage Work For Consideration

WO#	Activity Name	Outage #	DEPT	Resources	Expected Duration	GAR Number	Sys	^Equip Description	WO Type	DATE ADDED TO LIST	DUE DATE TO BE AT STAT 45	Holds	Current Status	Needed Reviews	Comments
Contingency Dual Unit Forced Outage List															
700022165	24-CL-12, CL water header piping replacement (Screenhouse)	2R32	MECH	MECHFT, CIW, OPS	48		CL	CL SYS LINE					INIT	11LT	

C. Any identified maintenance issue requiring a dual unit outage is put on the list so that, should a dual unit outage occur, there is a record of the items that need to be completed. If there was ever a need to schedule a dual-unit outage, then the items on the list would be scheduled for that outage.

D. It is correct that the "pipe replacement on cooling water system" was not scheduled or scoped into a specific future outage date. Rather, it was identified as needing to be added to the next available dual unit outage. In this case, this work was added to the Fall 2023 outage.

E. When this work was initially identified, it was anticipated that this work could be done while the plant was online. This inspection required performing this work at the edge of the circulating water bay. It was determined pre-outage while both units were online by maintenance personnel that the inspection should not be performed while the circulating water bay was running because it presented a safety hazard for personnel performing the work. The safety hazard stems from the proximity of the inspection to a plant water source that uses four 147,000 gallon per minute pumps, working at 2,000 horse power, to pump river water through the condensers. In order to prevent pump damage and avoid overflow above the bypass gates in the screenhouse during pump shutdown, the bay would need to be drained if the pumps are shut off. In order for the circulating water bay to be taken offline, both units must be offline.

F. Please see subpart E.

G. A dual unit outage was required for the plant screenhouse stop log rail guide inspection to be performed safely. See subpart E above.

H. Critical path activities are activities that drive outage duration.

I. A dual unit outage was required for this work, and this would be critical path work during a dual unit outage. Duration of shutdown and startup activities for both units is not included as part of the estimated critical path duration.

J. Critical path is best depicted as shown in the Company's response to DOC Information Request (IR) No. 49, Attachment B. All cells shown in blue on the "Flow Chart" tab of Attachment B show the cable replacement activities which

drove outage duration. In this scenario, "pipe replacement on cooling water system" and "plant screenhouse stop log rail guide inspection" were not driving the outage duration and, therefore, were not critical path projects because they could be done while the cable replacement was being done. Had these issues not been addressed during the Fall 2023 forced outage, such that a future dual unit would be required to fix them, they would be considered critical path.

K. This is correct. Whether an item is critical path can depend on the other projects scheduled for the same outage. If a future dual unit outage were performed and included other work that was scheduled to take more time to perform than these two activities, then these activities would not be critical path. However, the cooling water pipe repair would have had to be performed at some point in time, and no other future dual unit outage was scheduled, so the assumption is that this would drive critical path.

Witness:	n/a
Preparer:	Amanda J. Jepson
Title:	Manager, Nuclear Regulatory Policy
Department:	Nuclear Policy Planning
Telephone:	651-212-1679
Date:	September 3, 2025