BEFORE THE COURT OF ADMINISTRATIVE HEARINGS

FOR THE

MINNESOTA PUBLIC UTILITIES COMMISSION

STATE OF MINNESOTA

In the Matter of the Petition of the City of Slayton for the Determination of Compensation for City Acquisition of Xcel Energy Electric Service Territory	MPUC Docket No. E-002, PT-7157/ SA-25-129 CAH Docket No. 25-2500-40870

SURREBUTTAL TESTIMONY OF DAVID BERG
ON BEHALF OF THE CITY OF SLAYTON

January 22, 2025

Exhibit ___

PUBLIC DOCUMENT

I. INTRODUCTION

Q. Please state your name and title.

A. My name is David Berg and I am the Principal of Dave Berg Consulting, LLC.

Q. Are you the same David Berg that presented direct and rebuttal testimony in this matter on behalf of the City of Slayton?

A. Yes I am.

Q. What is the subject of your surrebuttal testimony in this case?

A. The primary focus of my surrebuttal testimony is to respond to certain aspects of rebuttal testimony provided by Department of Commerce witness Cuong Ngo and Xcel Energy witness Lisa Peterson.

Rebuttal Testimony of Cuong Ngo

Q. Does Mr. Ngo mention the compensation factors under Minn. Stat. § 216B.44 and Minn. Stat. § 216B.45?

A. Yes he does. On page 4 of his rebuttal, lines 18-22 he states the following: "Minn. Stat. § 216B.44 applies when a municipal utility extends its assigned service area into territory served by another utility. It defines 'appropriate value' using the same four factors as Minn. Stat. § 216B.45 and has been applied in numerous contested cases and settlements. Previous Commission orders pertaining to Minn. Stat. § 216B.44 therefore provide extensive guidance on how to interpret and quantify 'original cost less depreciation,' 'loss of revenue,' 'integration expenses,' and 'other factors' in the context of municipal acquisitions."

Q. Do you agree with his assessment that the 216B.44 cases provide "extensive guidance" on how to interpret the four compensation factors?

A. I agree that they provide guidance that is important for consideration in this 216B.45 matter with the understanding that the unique aspects of each case are also important.

Q. **Does Mr. Ngo make a statement in support of his conclusion regarding a ten-year compensation period for loss of revenue?**

A. Yes he does. On page 10, lines 7-10 he states*: "Applying a ten-year horizon here aligns this case with long-standing Commission practice, balances the need to compensate real economic loss against the risk of speculative forecasts, and gives Xcel a reasonable period to adjust its system and customer base to reflect the changes caused by the City."*

Q. **Do you agree with Mr. Ngo's assertion that based on "long-standing Commission practice, the ten-year period is "a reasonable period"?**

A. I do not. It is important to also recognize that in the Olivia case, where the 10-year period was first used, the Commission also explicitly stated: "[T]he Commission does not rule out the possibility that evidence in other acquisition proceedings would lead to a different determination of the appropriate period for payments in a loss of revenue calculation."[1] I have presented evidence in my direct (pages 37-48) and rebuttal (pages 18-27) testimonies supporting a five-year time period for loss of revenue in this unique case. Mr. Mark Fritsch has also testified in favor of a five-year compensation period in his rebuttal testimony (pages 9-10 and 11-15).

Q. **Does Mr. Ngo state that the loss of revenue should include future Slayton customers and growth?**

A. Yes he does. The use of a mill rate compensation, as I have suggested and is also in line with recent Commission precedent automatically adjusts for growth (whether from new or existing customers). Use of a mill rate for compensation would also account for the possibility of no growth in Slayton, or even declining sales. On page 11 of Mr. Ngo's rebuttal testimony, he agrees with the use of a mill rate for the loss of revenue payment and correctly states, "*This approach aligns with the Commission's § 216B.44 practice, tying compensation to actual load; and reduces the risk of over- or under-compensation if actual growth differs from forecast."* (lines 15-17, page 11 of Ngo rebuttal testimony).

[1] MPUC Order After Rehearing, Docket No. E-288,136/SA-85-93, October 1, 1986

Q. Do you agree with Mr. Ngo's recommendations regarding fixed costs relative to avoidable costs?

A. No, I do not. On page 10, lines 3-6 he states*: "Fixed costs, such as most production plants, transmission backbone, general plant, and shared administrative overhead, are not immediately avoidable and should not be treated as avoided unless the City can show that these costs will actually decline as a result of Slayton's departure over the ten-year period."* Mr. Ngo incorrectly assumes that costs cannot be avoided unless they decline. This assumption ignores the Rochester[2] case I reference later in this surrebuttal testimony as well as in my direct testimony (pages 24-27) regarding production, based on the utility's ability to adjust its operation and mitigate losses by efficiently using its assets elsewhere in its operations. Further, Mr. Ngo's statement regarding transmission backbone ignores the fact that Xcel gets its transmission revenue requirement from MISO as covered in detail by City witness Mark Mitchell. Lastly, Mr. Ngo mistakenly assumes the burden is on the City to show that Xcel is ***not*** entitled to compensation.

Q. Does Mr. Ngo make any recommendations regarding Xcel witness Peterson's inclusion of the SLW substation in the "other appropriate factors" category of compensation?

A. Yes, on line 6, page 13 through line 2 page 14 he states:

> **"***Q. How should the Commission treat potential stranded substation investment?*
>
> *A. If the record shows that a specific substation or similar asset was primarily justified by Slayton's load and will become significantly underutilized or unused after transfer, it may be appropriate to include some portion of its net book value in just compensation under 'other appropriate factors.' However, I conclude that it may be appropriate for the Commission to:*
>
> *• Require Xcel to analyze how that asset will be used after the transfer, including its value to remaining customers and the regional system;*

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[2]*In the Matter of the Application by the City of Rochester for an Adjustment of its Service Area Boundaries with People's Cooperative Power Association, Inc.*, Docket No. E299, 132/SA-93-498 ORDER DETERMINING COMPENSATION AND DENYING MOTION TO DISMISS (Nov. 30, 1995).

• Limit any stranded-asset recovery to the portion clearly attributable to the loss of Slayton; and

• Ensure that any stranded-asset amount is not already embedded in the loss-of-revenue analysis (for example, through a substation-related cost category), to avoid double-counting.

My testimony does not recommend that any asserted impact be recognized as an 'other appropriate factor' or assign a magnitude to such impacts; rather, it identifies the types of issues that have been treated as 'other factors' in prior municipal acquisition orders so the Commission can evaluate whether similar treatment is warranted on this record."

Q. Do you agree with Mr. Ngo's assessment listed directly above?

A. No I do not. He states that related to the substation: "*it may be appropriate to include some portion of its net book value in just compensation under 'other appropriate factor'.* In my analysis I have properly addressed the unavoidable portion of the substation attributable to Slayton and included it in the loss of revenue compensation.

Q. Does Mr. Ngo reach any other notable conclusions in his rebuttal testimony?

A. Yes, he lists several conclusions on line 13, page 14 through line 5, page 15 of his rebuttal testimony. With out addressing each item, it is important to recognize that he leads into his conclusions with*: "I conclude that it may be appropriate for the Commission to:"*
While I do not necessarily agree with all of his conclusions, I believe the record in this case gives the Commission a number of things to consider in making its decision. There are significant facts that necessitate consideration of the unique aspects of this specific matter, as I address further below.

Rebuttal Testimony of Lisa Peterson

Q. Ms. Peterson states in her rebuttal testimony that your loss of revenue calculations are not reasonable, extreme, and not consistent with other decisions of the Commission

(pages 2 and 3 of her rebuttal testimony). Do you agree with her portrayal of your loss of revenue recommendations?

A. No I do not. My methodology and calculations are consistent with Commission precedent applied to the very different circumstances of Xcel operations as compared to cooperatives, service area in the City of Slayton and Xcel's ability to adjust its operations to mitigate its damages as compared to the ability of much smaller cooperatives to make adjustments.

Q. Ms. Peterson lists a summary of Minn. Statute 216B.44 territory acquisitions in Table 1 on page 4 of her rebuttal testimony. Would you portray her recommended loss of revenue payment as reasonable when compared to previous Commission rulings.

A. No I would not. In Table 2 on page 46 of her rebuttal testimony, she proposes a fixed annual payment of $3,650,641 for loss of revenue. Based on her 2025 annual sales in Slayton of 20,501,564 kWh as calculated from her Exhibit__(LRP-2), Schedule 4, a mill rate consistent with her recommendation would be 178.1 mills/kWh (17.81 cents/kWh) for a period of 20 years. Ms. Peterson's effective mill rate is almost 6 times as much as the highest mill rate (30 mills) shown in her Table 1 summary of pervious Commission cases.

Additionally, Ms. Peterson reports the total gross revenue for sales in the City of Slayton for 2025 in her Exhibit__(LRP-2), Schedule 4 as $2,914,221 which equates to a gross revenue average of 142.1 mills/kWh (14.21 cents/kWh) without differences in customer classes. This means Ms. Peterson's loss of revenue payment is 125% of total gross revenues for the City of Slayton. Ms. Peterson's advocacy of an effective loss-of-revenue amount that exceeds gross revenue and is almost 6 times more than previous commission decisions. That is extreme, not consistent with past Commission decisions on Section 216B.44 compensation, and not a reasonable outcome.

Q. In her rebuttal, does Ms. Peterson make reference to the size of this proposed acquisition as compared to previous cases in regard to her opinion of appropriate level of loss of revenue payment?

A. Yes she does. On page 6 of her rebuttal, lines 4-8, Ms. Peterson states:

> *"In contrast, this matter involves approximately 1,200 existing customers and fully developed infrastructure to serve the entire City of Slayton. Given the infrastructure and established revenue stream of these existing customers, loss of revenue to the utility should be larger, not smaller, than previous cases decided under section 216B.44."*

Q. Do you agree with her contention?

A. No I do not. The absolute size of the acquisition is less important than the relative percentage of an overall system and the ability of the incumbent utility to be able to adjust its operations to account for the acquisition. I make several references in my direct testimony to this concept and will not repeat them all here. As I stated in my direct testimony, page 45, line 9, Slayton accounts for 0.071% of Xcel's annual sales. This is the appropriate basis for considering the size of the acquisition and determining the ability of Xcel to make appropriate adjustments.

Q. Does Ms. Peterson make an observation of how the result of this case could impact future potential acquisitions?

A. Yes she does, on page 7 lines 6-8 she states: *"Adopting a methodology in which only 2.8 percent of lost revenues are the responsibility of the community leaving the system could encourage other communities to consider leaving the Xcel Energy system."*

Q. Do you agree with her concerns regarding future impacts of this case?

A. **I do not.** Minnesota Statute 216B.45 under which this acquisition is allowed was passed in 1974, 52 years ago. Ms. Peterson expresses concern that awarding what she views as too little compensation could encourage similar municipal acquisitions. While this concern could be valid if the result were in fact too low, I have shown that my methodology and calculations are in line with Commission precedent and lead to a fair and equitable result here, based on the unique facts of this case. I also note that Ms.

Peterson's conclusory description that my methodology compensates Xcel for "only 2.8 percent of [its] lost revenues" is based on unproven and overly optimistic projections of growth for a small rural community, which are then compounded over an unprecedented 20-year compensation period.

Conversely, interpreting the statute to require compensation in line with Ms. Peterson's recommendation of $44 Million (or 125% of Slayton's gross revenue for 20 years) would provide a windfall to Xcel and lead to a result that no reasonable municipality would ever choose to accept – and which would effectively render the statute meaningless.

Q. Does she mention other larger cities to make her point about the danger of more acquisitions to Xcel?

A. Yes she does. On page 7 of her rebuttal testimony Ms. Peterson references Marshall (with 7 times the population of Slayton, and which city has been a municipal utility for more than 100 years), and Mankato (with 20 times the population of Slayton). She then makes ratioed conclusions regarding revenue impacts based on population.

Q. Is her use of ratioed impact appropriate on a gross revenue basis?

A. No, it is not. Gross loss of revenue is not the point of loss of revenue compensation. It's **net** loss of revenue as defined by the Commission that is important. Moreover, other cities and the incumbent utility may have very different facts affecting the net loss of revenue analysis.

Q. Does Ms. Peterson still advocate a 20-year loss of revenue time period in her rebuttal?

A. Yes she does.

Q. Do you have any additional responses regarding her loss of revenue time period beyond what you have mentioned in your direct and rebuttal testimonies?

A. In my direct and rebuttal testimonies I state the reasons why my proposed five-year time-period is much more appropriate than 20 years on these facts. In my rebuttal testimony I specifically address the direct testimonies of both Ms. Peterson and Dr. Sun and their incorrect reliance on "asset life" and "planning periods." I give specific reasons why their arguments supporting a 20-year conclusion are not applicable.[3]

Q. Relative to her discussion of time periods and ability to adjust the system, does Ms. Peterson accurately represent your direct testimony?

A. No, she does not. On page 10, lines 3-5, she states: *"Based on the discussion on pages 43 to 44 of City witness Berg's testimony, City witness Berg seems to think that Xcel Energy will lay off employees to 'adjust' to Slayton's exit."* What I actually stated on page 44 of my direct testimony, lines 9-17 is: *"Xcel has 4,617 employees (as shown in Attachment E, a Minnesota information sheet from Xcel's web site) in Minnesota. Many of these employees would be full-time but likely many are part-time. It has an extensive fleet of equipment that can be allocated where needed and moved from areas where not needed. At any given time they are advertising to hire new employees. Attachment F is a screenshot from Nov 19, 2025 from Xcel's web site showing that they were advertising for 50 positions in Minnesota. They have many opportunities to adjust workforce, adjust equipment purchases, move personnel and equipment around the Xcel system. These are not opportunities that small rural cooperatives have with limited staff, equipment and facilities."* I never suggested Xcel lay off employees.

Q. Does Ms. Peterson's rebuttal take issue with the data you utilized in your testimony?

A. Yes it does. On page 17 of her rebuttal testimony, lines 5-12, Ms. Peterson states:

> *"The Company's rate case is currently pending. City Witness Berg relied on the Class Cost of Service Study (CCOSS) filed on November 1, 2024 with the Company's Direct Testimony. This information was provided to the City in September 2025. On November 25, 2025, the Company filed Rebuttal Testimony in the rate case, reducing its overall rate request. As a result, City witness Berg's analysis is based on a revenue requirement that is no longer being requested. My analysis avoids this problem, because it uses revenue data based on existing rates, rather than proposed rates not authorized by the Commission."*

[3] Berg Direct Testimony pages 47-48; Berg Rebuttal Testimony pages 18-29.

Q. Is her statement above regarding your use of the November 1, 2024 revenue requirement material?

A. No, it is not. Ms. Peterson states that she uses revenue data based on existing rates. Her total reported 2025 Slayton revenue from page 1 of her Exhibit__(LRP-2), Schedule 4 is $2,914,221. In my direct testimony in Attachment C, I utilize allocated revenue requirements as a proxy for revenue. In page 1 of Attachment C, I show in row 26, column (20), 19,614,508 kWh of annual sales in Slayton. In row 8, column 25 on the same page I show a weighted revenue requirement for Slayton of $0.1535 per kWh. This average weighted revenue requirement of $0.1535 per kWh times 19,614,508 kWh yields an annual revenue requirement of approximately $3.0 million. This is very close to Ms. Peterson's revenue of $2,914,221.

I also note that Xcel filed its revised revenue requirement on November 25, 2025. The trade secret CCOSS revenue requirement based on the original filing was provided to the City for this case in September of 2025. Xcel did not make the City aware of the updated revenue requirement nor give the comparable CCOSS revenue requirement for the update. The difference in numbers would have little effect on my recommendation, however.

Q. Did you find anything in Xcel's public data regarding its revised rate filing?

A. Yes. Attachment L to this surrebuttal testimony is the Rebuttal Testimony filed by Amy Liberkowski on October 10, 2025 in Xcel's general rate case Docket No E002/GR-24-320. Her Table 5 from page 20 of her Rebuttal Testimony is shown below.

Table 5
MYRP Revenue Requirements ($s in millions)

	2025	2026	Total
Initial Request	$353.3 9.6%	$137.4 3.6%	$490.7 13.2%
Supplemental Request	$344.3 9.4%	$129.3 3.3%	$473.6 12.7%
Rebuttal Request	$208.4 5.8%	$156.9 4.2%	$365.3 10.0%
Increase/(Decrease) from Initial to Rebuttal	($144.9) (3.8%)	$19.5 0.6%	($125.4) (3.2%)

As shown above, Xcel has reduced its 2025 revenue requirement increase by $144.9 million while slightly increasing its 2026 revenue requirement increase by $19.5 million. The overall impact is a decrease of $125.4 million. It has reduced its total rate increase request over the applicable two years from 13.2% to 10.0%.

Q. What do you conclude from this revised rate request from Xcel in its pending rate case?

A. Ms. Peterson argues that there is little Xcel can do to adjust its operations based on changing circumstances. Yet somehow, in its rate case, Xcel was able to trim $125.4 million from its revenue requirement in less than a year. This revenue requirement reduction amounts to 25.6% ($125.6 million/$490.7 million) of the revenue requirement increase Xcel submitted in its initial rate filing. This is just one example of how Xcel – as a large, vertically-integrated enterprise – has multiple points at which it can quickly adjust its operations to account to changed realities. A much smaller rural electric cooperative would strain to make similar adjustments, if it were even possible.

Q. Does Ms. Peterson, in her rebuttal testimony, make reference to the level of her proposed compensation that is related to her stated lost revenue due to generation and transmission assets?

A. Yes, on page 12, lines 1-3, she states: *"In comparison, the costs for generation and transmission assets represents approximately 80 percent of total costs for customers."*

Q. Do you agree with her calculation of the 80% value?

A. Based on the calculation shown in footnote 23 on page 12 of her rebuttal testimony, I agree with her 80% representation of her view of the overall level of generation and transmission costs as compared to total costs. This shows that the impact of her conclusion -- that most of the generation and all of the transmission is unavoidable or "stranded"-- constitutes a very significant portion of her unreasonably high loss of revenue calculation.

Q. Do you agree with Ms. Peterson's rebuttal assertion that generation and transmission costs are "unavoidable" and should be compensated in the loss of revenue calculation?

A. No, I do not. Related to the generation component, Ms. Peterson states on page 19 of her rebuttal testimony, lines 18-21 she states: *"Embedded costs are costs associated with investments that have already been made. These costs cannot be easily reversed. For example, the Company cannot cancel small parts of power purchase contracts or eliminate fractions of its nuclear power plants or the staff that run them."* She continues on page 20 of her rebuttal, lines 23-25: *"I further disagree with City witness Berg's assertions that the Company will replace future capacity additions or sell the excess capacity in the regional market."* Additionally, on page 21, lines 4-11 of her rebuttal testimony Ms. Peterson also states: *"First, as noted above, Slayton's exit will not reduce generation costs because Slayton is not large enough that its exit would change the size, type, or timing of* *generation additions. Second, the costs in the fixed production category are related to existing generation units, not future generators that have not been selected or constructed."*

In my direct testimony the generation issue is addressed from page 24, line 12 through page 27, line 19. I expand in my rebuttal testimony from page 9, line 13 through page 13 line 7, and continuing from page 19, line 8 through page 21, line 15. My generation comments continue in my rebuttal testimony from page 37, line 21 through page 39, line 12. I will not repeat testimony I have already submitted.

I will add, based on Ms. Peterson's rebuttal testimony, she suggests that: (1) all existing generation was planned and built for current customers, (2) that new generation is for new customers, and (3) that the two components are separate and distinct. I disagree with these characterizations. First, electricity is fungible and does not serve any particular customers. Second, Xcel is a large utility with extensive generating assets (approximately 10,000 MW of generation). As such, it is responsible utility planning to consider **all factors** in generation planning – including load growth, loss of load, generation retirements, market conditions and other related impacts on generation. The idea that old and new generation assets are completely unrelated would be irresponsible planning and ignores the reality of the functional operation of a large integrated utility located within a multi-utility, multi-state operational area (MISO).

Q. As you quoted above, Ms. Peterson states that Slayton is not large enough to impact the size, type or timing of generation additions. How do you respond to this concept?

A. First, Ms. Peterson has mischaracterized my testimony. On page 14, line 23 through page 15, line 1 she states: *"City witness Berg has not identified any realistic way in which future load growth can reduce the costs of Xcel Energy's system. In fact, it is likely that significant* *load growth — like the addition of data center customers — will require the addition of generation assets."* I do not state that load growth will **reduce costs** for Xcel, I state that it will **reduce lost revenue** as Xcel can utilize freed generation from Slayton to serve new customers, thereby mitigating cost impacts of the loss of Slayton's load and customers.[4] Secondly, this illustrates an important difference in how Ms. Peterson and I view compensation for revenue loss. Ms. Peterson states that load growth will require the additions of generation assets to meet Xcel's growing energy needs while simultaneously ignoring the positive benefit of Slayton exiting the Xcel system. If Xcel requires **new** generation, and the filed Xcel IRP's I reference in my rebuttal testimony show that need, Xcel will have available a portion of existing generation due to the exit of Slayton customers to help fill that need. The fact that the generation amount freed up by the Slayton needs is small does not diminish its value to supplant future additions – and thereby mitigate the loss of revenue.

Q. You also quote Ms. Peterson above when she states in her rebuttal testimony: *"… the costs in the fixed production category are related to existing generation units, not future generators that have not been selected or constructed."* Do you have any further response to that statement?

A. Yes. Future generation costs will likely be higher than current costs. As I stated in my rebuttal testimony, page 28, lines 6-11, part of Xcel's justification for its recent rate increase filing is "transforming our generation fleet." If additions to the generation fleet require rate increases, the additions are likely more expensive than the current generation fleet. This shows the value to Xcel of Slayton capacity requirements. Slayton represents 4 MW of generation that can be used to replace the need for new generation,

[4] Berg Direct Testimony pages 24-27.

or 4 MW of generation that would not require "transforming" as stated by Xcel in its rate filing as I reference above from my rebuttal testimony.

Q. Do you agree with Ms. Peterson's rebuttal to your direct testimony assertion that Xcel could sell excess capacity in the MISO market?

A. No, I do not agree with her. On page 21, line 21 through page 22, line 7 she states: *"City witness Berg argues that the Company can sell Slayton's capacity on the markets of the Midcontinent Independent System Operator (MISO). Company witness Sun analyzed this possibility in her Direct Testimony, and concluded that it would not be possible to offset the lost revenue through capacity sales. Witness Sun further concluded that it would not be able to predict the amount of revenues received in any year in the future, and that even if the maximum possible amount of revenues were received it would offset only a small portion of the fixed production lost revenues from Slayton. In contrast, City witness Berg has not provided any evidence to support his claim that the lost revenue related to fixed production costs can be fully offset by revenues from the MISO market."* This is incorrect. In my rebuttal testimony, page 40, line 18 through page 43, line 2, I show how Dr. Sun, in her direct testimony, understated the value of excess capacity in MISO due to the loss of the Slayton load and I calculate the offset to fixed production costs available to Xcel in the market.

Q. Do you agree with Ms. Peterson's rebuttal testimony regarding the value of generating capacity in the MISO market as it relates to Xcel?

A. Again, I do not agree with her. In her rebuttal testimony at pages 21 and 22, Ms. Peterson relies on the direct testimony of Dr. Sun regarding the value of capacity in the MISO market. Dr. Sun, on page 10 of her direct testimony, lines 22-25, stated: *"These estimated net capacity auction revenues are negligible and do not appropriately compensate the Company for the lost retail sales revenues allocated to recovering fixed production costs, as described by Company witness Peterson."*

Q. Did you find Xcel information related to Dr. Sun's testimony regarding market sales of capacity?

A. Yes, I did and it contradicts her testimony. Attachment M to this surrebuttal testimony is the November 1, 2024 Direct Testimony of Benjamin C. Halama filed as part of Xcel's general rate case Docket No. E002/GR-24-320. Also, Attachment N is Mr. Halama's Rebuttal Testimony in the same general rate case filed October 10, 2025. In his 2024 Direct Testimony regarding Xcel's revenue requirement in the rate case, in Exhibit__(BCH-1), Schedule 11a, page 1 of 2, line 4, column (14) for test year 2025, Mr. Halama shows **$2,128,000 of Excess Capacity Proceeds**. In Exhibit__(BCH-1), Schedule 11b, page 1 of 2, line 4, column 14 for test year 2026, he shows zero revenue associated with Excess Capacity Proceeds.

Q. Did Mr. Halama's Excess Capacity estimates change in his Rebuttal Testimony in the general rate case?

A. Yes, they changed significantly. In Exhibit__(BCH-3), Schedule 3A, page 2 of 6, in line 48, column (17), his test year 2025 revenue requirement included **$38,744,000 of Excess Capacity Proceeds**, an increase of $36,616,000 from his Direct Testimony. In Exhibit__(BCH-3), Schedule 3B, page 2 of 6, in line 48, column (17), his test year 2026 revenue requirement included **$40,262,000 in Excess Capacity Proceeds**, an increase of

$40,262,000. On page 13 of Mr. Halama's rebuttal rate case testimony, in lines 1-3 he states: *"The Company agrees it is reasonable to update the capacity revenue baseline amounts included in 2025 and 2026 as Department witness Golden recommends."* In rate case testimony, filed with the Commission on October 10, 2025, Xcel has conceded that there is value of excess capacity in the market, which is a direct contradiction to the testimonies from Ms. Peterson and Dr. Sun in this Slayton matter.

Q. Ms. Peterson criticized your direct testimony as it relates to generation capacity, where you referred to the Rochester case decision from 1995.[5] Do you agree with her criticism?

A. No, I disagree. On page 22, line 9 through page 23, line 13 Ms. Peterson gives two reasons she believes the Rochester case is "*not a good comparison* (Peterson rebuttal page 23, lines 12-13)." On page 22, line 22 through page 23, line 3, she states: *"First, in Rochester, the Commission was evaluating the possibility that Rochester's expansion in service territory could increase wholesale rates from Dairyland to the distribution utility. City witness Berg is attempting to apply reasoning about speculative wholesale rate increases with costs related to existing, already-built and already-running generation."*

In my opinion, on this issue, the Rochester case is very similar to this case. In *Rochester,* the cooperative was arguing that fewer sales would increase wholesale power costs which in turn would increase retail rates. In this case, Xcel is arguing that loss of sales in Slayton will spread existing generation costs over fewer sales resulting in retail rate increases.

[5] *In the Matter of the Application by the City of Rochester for an Adjustment of its Service Area Boundaries with People's Cooperative Power Association, Inc.*, Docket No. E299, 132/SA-93-498 ORDER DETERMINING COMPENSATION AND DENYING MOTION TO DISMISS (Nov. 30, 1995).

These cases are directly parallel in this regard and therefore the *Rochester* case is applicable and highly instructive here.

Ms. Peterson also states on page 23 of her rebuttal, lines 6-13: *"Second, the utility's generation capacity position was relevant in Rochester because the dispute was about undeveloped areas that were not already being served. The Commission noted that the case was 'no longer [about] . . . losing an opportunity to spread sunk costs over more kilowatt hours of sales,' because the utility would have had to build a new power plant to serve the area in question. In contrast, this case is directly about the opportunity to spread sunk costs over the sales from Slayton. As a result, the analysis in the Rochester case is not a good comparison."*

I disagree with that assertion, also. In my opinion, these cases (Rochester and Slayton) are still similar and relevant. The key issue from the Rochester case decision, as I stated on page 25 of my direct testimony, lines 9-12 was: *"People's' wholesale supplier does not currently have abundant capacity. Dairyland had no excess capacity in 1994 and none in 1995. It may have a small amount between 1996 and 2000, but it should be able to sell that capacity on the wholesale market."* Importantly, Xcel is reporting a need for significant generation capacity additions moving forward as part of its IRPs. This means that Xcel can mitigate the effects of the loss of the Slayton load by selling newly available capacity in the market, replacing or delaying the addition of new capacity or using it for other growth or a combination of all three. The 4 MW of Slayton capacity is therefore not "stranded" in any way.

Q. Are there other aspects of the Commission's opinion in the Rochester case that Ms. Peterson failed to address?

A. Yes, in my direct testimony, page 26, lines 2-8, I also quoted from the Commission's Rochester decision:

> "Finally, the customers at issue represent an infinitesimal part of Dairyland's total load. The usage of current customers in the areas at issue is .017% of Dairyland's total sales; projected usage of future customers is .412%. The de minimis impact of these sales on Dairyland, coupled with the absence of substantial evidence that their loss will adversely affect wholesale rates, precludes factoring wholesale rate increases into compensation in this case."

I added in my direct testimony (page 26) after the above listed quote from the Rochester decision, the ways this portion of Rochester was also applicable to this case relative to generation.

Q. In her rebuttal, Ms. Peterson criticized your view that transmission costs should be excluded from the loss of revenue. Do you agree with her assertions?

A. I disagree with them. On page 25 of her rebuttal testimony, lines 21-22 she states: *"City witness Berg recommends that costs for the transmission system are fully avoidable and should be excluded from the lost revenue calculation. I disagree."*

I stand by my conclusion that transmission costs are fully avoidable here. On page 27 of Ms. Peterson's rebuttal, lines 3-6, she states: *"I anticipate that City witness Berg will provide additional analysis on this topic in his Rebuttal Testimony. I will evaluate that information and provide the Company's final recommendation in my Surrebuttal Testimony."* As anticipated, I have additional information in my rebuttal testimony, and City witness Mr. Mark Mitchell also provides additional information in his rebuttal and surrebuttal testimony in this matter. Mr. Mitchell and I both conclude that transmission costs are avoidable.

Q. Do you agree with Ms. Peterson's rebuttal testimony statements about the transmission system additions in the Slayton area by Great River Energy?

A. I disagree with Ms. Peterson's comments on page 26 of her rebuttal testimony, lines 6-8 where she states: *"Further, City witness Berg's analysis also does not incorporate the fact that, according to discovery responses from Slayton, Slayton would no longer be a transmission customer of Xcel Energy. In fact, it appears that Slayton intends to bypass Xcel Energy's existing transmission system in favor of a transmission extension from Great River Energy (GRE)."* She refers to Mr. Krug's direct testimony Exhibit __(ADK-1), Schedule 8, page 1 of 2 which states*: "The City intends to receive transmission and substation services from Great River Energy and Nobles Cooperative Electric via a new substation designed and constructed by Nobles south of the City of Slayton on property located at or about 851 15th Avenue, Slayton, MN, 56172 (Murray County Tax Parcel ID 20-021-0012), which will be served by a Great River Energy transmission line extension."* On page 48, line 14 through page 49, line 2 of my rebuttal testimony, I explain the plan for the transmission extension and the fact that the Xcel transmission line will still be utilized as it is now to deliver power to Slayton. Great River Energy (GRE) extension is attached to and extends from Xcel's existing 69-kV line.

Q. How did you acquire the information you describe above regarding the transmission extension plan?

A. I called the CEO of Nobles Electric Cooperative (Nobles), Adam Tromblay, and asked him. In his response, Mr. Tromblay also told me that the new substation has been part of Nobles' planning documents since well before Slayton began the process of establishing a municipal utility. Nobles built the new substation to replace its old substation (as I reference on page 48 of my rebuttal testimony). My understanding is that this project is completed, energized, and is currently in service as of the date of this testimony. Nobles/GRE did not build the transmission and substation to serve Slayton. In my opinion, that would not have been prudent because the Slayton acquisition has not happened yet.

Q. Why do you believe it is relevant that the transmission extension built by GRE was not planned and built to serve Slayton?

A. On page 26 of her rebuttal testimony, lines 10-15, Ms. Peterson states: *"If a new GRE transmission line is constructed for Slayton, it would increase costs for transmission in the entire MISO zone unless the costs for the new line are directly assigned to Slayton. The Company cannot estimate the potential impact of this cost increase and the ultimate impact on rates, which will depend on the location, cost, and cost allocation plans for the GRE transmission extension."* The short transmission extension built by GRE is already built. It is not dependent on the Slayton acquisition, nor was it built by GRE to serve Slayton. Any impact on MISO zonal costs has already occurred. It is inappropriate to claim the costs should be paid by Slayton as a result of the acquisition.

Q. Would the information regarding the plans of Nobles/GRE to add the transmission extension and new substation have been available to Xcel?

A. Yes. Xcel could also have called Nobles Cooperative, inquired with GRE, or inquired with its own transmission personnel, since the GRE/Nobles tap on Xcel's transmission line could not have happened without Xcel's cooperation. These types of projects are typically planned well into the future and Xcel transmission personnel would necessarily have been aware and involved.

Q. Did Ms. Peterson's rebuttal testimony adjust her estimate of avoidable distribution costs in her calculation of loss of revenue?

A. Yes she did. She **lowered** the percent of distribution costs she deemed avoidable from 1.4% in her direct testimony to 0.1% in her rebuttal testimony as shown in Exhibit __(LRP-2), Schedule 4, page 6 of 6.

Q. Have you done additional analysis on her calculations contained in her rebuttal?

A. Yes, upon further review, her logic as shown in Exhibit __(LRP-2), Schedule 4, page 6 or 6 is flawed.

Q. How is her analysis flawed?

A. Below is Ms. Peterson's table from Exhibit __(LRP-2), Schedule 4, page 6 of 6, showing retail revenue requirements and her resulting percentage of each that she states is avoidable. It is important to note that her values in the columns are for the entire state of Minnesota and are presented in thousands of dollars ($000). The total MN revenue requirement she shows is approximately $3.7 billion.

Total Retail Revenue Requirement	MN	Res	Sm Non-D	Demand	St Ltg	Percentage Avoidable
Total Customer	405,478	335,540	24,302	20,215	25,421	27.1%
Variable Production	1,692,348	537,234	49,816	1,099,312	5,986	36.4%
Fixed Production	893,802	326,389	25,316	540,925	1,172	0.0%
Transmission	398,439	157,052	11,011	230,376	0	0.0%
Total Distribution	322,948	156,591	8,706	156,274	1,376	0.1%
Costs Avoided	726,473	286,810	24,739	405,845	9,079	
Costs NOT Avoided	2,986,542	1,225,996	94,413	1,641,256	24,877	
Total Revenue Requirement	3,713,015	1,512,806	119,152	2,047,102	33,955	
% of Costs Avoided	**19.57%**	**18.96%**	**20.76%**	**19.83%**	**26.74%**	

Q. What information in this table is pertinent to the flaw in Ms. Peterson's analysis?

A. I will make some numerical comparisons to her values for "Total Customer," "Variable Production" and "Total Distribution" as presented above. These values are relevant because Ms. Peterson states that a portion of the costs are avoidable.

Q. What does her Total Customer Percentage Avoidable of 27.1% indicate?

A. It is unclear. As I stated on page 17 of my rebuttal testimony lines 3-14, Ms. Peterson gives the 27.1% savings value without benefit of calculations or detailed assumptions. However, if you multiply the 27.1% avoidable times the total MN customer revenue requirement of $405,478,000 shown above, the total for the MN system would be $109,884,538. Ms. Peterson is certainly not advocating that not serving Slayton would save Xcel $109.9 million in customer costs. She appears to be using that calculation to calculate her total avoided costs by class in her Exhibit__(LRP-2), Schedule 4.

Q. Does she do something similar for the Variable Production category?

A. Yes, as I state in my rebuttal testimony, page 10, lines 25-28 Ms. Peterson states that fuel makes up 36.4% of the Variable Production category. Just like with the customer component shown above, 36.4% of the MN total system Variable Production value of $1,692,348,000 would be $616,014,672. Again, Ms. Peterson is not claiming Xcel will save $616 million in fuel costs by not serving Slayton. She again uses this in her overall calculation of avoided costs by class utilizing system-wide values.

Q. How does her calculation for the distribution costs differ from the customer and variable production numbers shown above.

A. She takes a different approach to calculate the distribution avoidable costs. As she states in her rebuttal testimony page 28, line 23 through page 29, line 4: *"In preparing to respond to City witness Berg, I identified a miscalculation in my Direct Testimony. As I explained in my Direct Testimony, in order to calculate the lost revenues related to distribution costs, it is appropriate to remove the costs related to the distribution assets that Slayton will purchase. For that reason, I calculated that 1.4 percent of the distribution costs should be avoided by removing the net book value of the Slayton distribution assets from the distribution amounts."*

In her rebuttal testimony (page 29, lines 6-14), she states she has corrected her calculation, which now results in only 0.1% of distribution costs classified as avoidable as shown in her Schedule 4 table shown above. She calculates her value by dividing the value of Slayton acquired distribution assets to the total Xcel Minnesota distribution assets to conclude that 0.1% of distribution costs will be saved by Xcel due to the acquisition. Her flaw is that 0.1% of total system distribution costs (by her assumptions) will be saved. The dollar amount of that savings would be 0.1% of $322,948,000 equal to $322,948 per year. However, Ms. Peterson takes the effective savings (by her calculation) of not serving Slayton and dilutes it by then dividing by the total revenue requirement to apply to her calculations. By her logic, Slayton customers pay the entire $323 million dollar Xcel Minnesota distribution revenue requirement and therefore only 0.1% of it is saved by not serving Slayton.

Q. Based on Ms. Peterson's rebuttal testimony, how much total distribution cost does she calculate is avoided by a Slayton acquisition?

A. Using numbers from the table included in her rebuttal testimony exhibit (I show the table above), I calculate her avoided distribution cost as follows. Her table numbers represent total Xcel Minnesota annual numbers. The total revenue requirement she shows is $3,713,015,000. Of that total revenue requirement, she lists $322,948,000 as total distribution related. She states that 0.1% of the distribution revenue requirement is avoidable. Based on these assumptions, on a system wide basis she calculated that $322,948 ($322,948,000 times 0.001) of distribution costs are avoidable. Her system-wide avoidable distribution costs are 0.0087% of the total system-wide revenue requirement ($322,948 divided by $3,713,015,000). Ms. Peterson does not actually calculate and show her number for effective avoidable distribution costs. I have calculated her imputed avoidable distribution costs for Slayton by using her system-wide calculations multiplied by the Slayton annual revenue. Based on her Slayton annual revenue of $2,914,221, her calculations result in an avoidable distribution cost due to not serving Slayton of $253.54 ($2,914,221 times 0.000087).

Q. Do you agree with her adjusted calculation as corrected by you above?

A. I don't agree that $322,948 is the correct annual value, but it is at least a more reasonable number as compared to the $253.54 I calculated from her testimony. As I stated in my rebuttal testimony, page 16, line 26 through page 17, line 2: *"Based on her direct testimony, 98.7% (100% less 1.3%) of the distribution costs paid by Slayton customers through the retail rates charged by Xcel actually subsidize the distribution expenses of other Xcel customers. This is a result that in my opinion is simply not possible. Aside from a portion of the substation which I address later in the rebuttal testimony, Xcel will clearly avoid all other distribution costs and they should be 100% avoidable."* I stand by that conclusion. Ms. Peterson's new calculation expands my conclusion based on her direct testimony, and she now advocates that 99.9% of the distribution costs paid by Slayton subsidize other customers. I acknowledge that this distribution analysis would have been better included in my rebuttal testimony, but I just realized based on Ms. Peterson's rebuttal correction why her calculations do not make sense.

Q. In her rebuttal testimony, does Ms. Peterson address the level of distribution costs included in Xcel's revenue requirement?

A. Yes she does. On page 11, line 25 through page 12, line 1 she states, *"As shown in Schedule 3 to my Direct Testimony, the costs of the distribution system represent approximately 8.6 percent of total costs for customers."* In footnote 22 on page 12 she provides the calculation: *"Distribution costs of 322,948 divided by total revenue requirement of 3,713,015."* She states that these numbers are in thousands of dollars and we can conclude they represent the entire Xcel system. For all Xcel customers, she concludes that

8.6% of revenue requirements are due to distribution costs, but the loss of Slayton and 100% of the Slayton distribution system, which Xcel will be compensated for in the facilities cost component, results in only 0.1% savings of the Slayton distribution revenue requirement.

Q. How much of her total avoided costs in her calculation are due to savings of the distribution system?

A. This is where the flaw in Ms. Peterson's calculations becomes apparent. In her table from Exhibit __(LRP-2), Schedule 4, page 6 of 6 shown above, total avoided costs for the total Xcel system utilizing her percentages equals $726,473,000. Total system distribution costs savings as calculated by Ms. Peterson are $322,948, as I state above. The distribution savings amount to only 0.045% of the avoidable costs ($322,948 divided by $7,726,473,000). The $322,948 of total system distribution cost savings is only 0.0087% of the total Xcel system revenue requirement ($322,948 divided by $3,713,015,000). According to Ms. Peterson, sale of a portion of Xcel's system amounting to 8.6% of total revenue requirements results in on 0.0087% of revenue requirement savings. Her calculated savings are almost 1000 times less than the allocated revenue requirement.

Q. What is the overall magnitude of the correction you have made to her avoided distribution cost calculation?

A. My calculations (using her numbers and correcting her assumptions) result in an increase of annual avoidable distribution expenses of $322,694 ($322,948 minus $254). In simple terms, $322,694 per year times Ms. Peterson's 20-year compensation period results in an understatement of $6,453,880.

Q. Should her analysis, as corrected by you, be utilized for this loss of revenue calculation?

A. No. The calculations I present in my direct testimony provide an accurate representation of the proper loss of revenue calculation. Relative to distribution, Slayton is acquiring all Xcel distribution assets in the City and Xcel will avoid all distribution expenses in Slayton.

Q. Does Ms. Peterson disagree with your direct testimony analysis regarding an adjustment to the loss of revenue based on load density in Slayton?

A. Yes she does. Her comments are from line 16 on page 30 through line 9 on page 34. I will address several of her statements. Her statements include:

- *"City witness Berg has not provided any evidence to support his claim that it costs more to serve Slayton than other parts of our system, and even if he had, it would not justify his recommendation."* (lines 4-6, page 31).
- *"City witness Berg's claim is based entirely on an overly simplified economic analysis about the "dollars per mile of line". That analysis does not provide any useful information about how much it costs to provide service in Slayton compared to the rest of our system."* (lines 10-14 page 31).
- *"First, the "dollars" per mile of line that City witness Berg refers to appear to be the amount of kWh sales in Slayton. But there is no basis to assume that the amount of kWh sales from Slayton has a direct relationship to how much it costs to provide service specifically in Slayton."* (lines 18-21, page 31).

- *"The Company's rates are the same for each customer class across the entire state and are not differentiated between different geographic areas or communities."* (lines 21-23, page 31).
- *"Second, the "mile of line" part of City witness Berg's analysis is entirely focused on distribution lines and ignores all other assets necessary to provide electric service. It is not reasonable to ignore the generation and transmission investments needed to provide service."* (lines 4-8, page 32).

Based on the five statements by Ms. Peterson listed above from her rebuttal testimony, I offer the following: It stands to reason that the longer a distribution line is, the more expensive it is to build and to maintain. In my experience, utilities routinely refer to distribution costs based on $/mile for both construction and maintenance. The concept of viewing density on a kWh per mile of line, is that it represents the apportioned revenue from customers per mile of line in any area. I recognize that all Xcel ratepayers in a given class pay the same rate. With less overall revenue per mile of line (based on lower kWh/mile density) to pay for distribution related costs, there is a lower effective margin for a lower density area, (equal revenues per kWh less higher cost per kWh due to lower sales density). It would be inappropriate to speak about miles of line for non-distribution assets such as generation. That is why the density adjustment I make in my analysis is only for the distribution related expenses.

Q. Has the Commission discussed density as it applies to a utility's cost to serve?

A. Yes. For example, I addressed this in my direct testimony on page 40, lines 14-20 from the Commission's Olivia[6] case. The Commission stated regarding areas of higher density: *"These comparisons clearly establish that the customers in the acquisition area are less expensive to serve than customers elsewhere on the system."* If higher density areas are less expensive to serve, it stands to reason that lower density areas are more expensive to serve. My distribution density adjustment is a reasonable estimation of the savings associated with not serving Slayton as compared to overall Xcel statewide averages.

Q. Does Ms. Peterson continue to advocate for a lump sum payment for loss of revenue rather than a mill rate paid based on actual sales over a period of time?

A. Yes she does. It is interesting that on page 37 line 19 through page 38, line 2 she states:

> "*As I explained in my Direct Testimony, if the Commission requires a payment over time, it is preferable to use a scheduled payment rather than a mill rate. Using a mill rate would expose both customers in Slayton and the Company to fluctuation in the amount of recovery, and would almost certainly result in a lost revenue payment that is either larger or smaller than what is ordered by the Commission."*

Several places in her testimony she makes reference to load growth. She continues to project load growth in excess of what is expected or has been experienced in Slayton. In her statement above, she cautions against a mill rate because, in her words, it will result in a lost revenue payment that is either larger or smaller than what is ordered by the Commission. However, if the Commission awards a loss of revenue based on a mill rate, which is consistent with *Redwood Falls, Grand Rapids* and *Buffalo* compensation cases as she shows in her Table 1 on page 4 of her rebuttal testimony, there is no need to argue

[6] MPUC Docket No. E-288, 136/SA-85-93

about growth rates over a period of time. The mill rate self-adjusts the annual payment based on actual sales. This was the rationale behind the Commission adopting mill rate approach for loss of revenue.

Q. Does Ms. Peterson continue to advocate for a full payment by Slayton for the entirety of the SLW substation?

A. Yes she does. I addressed this in my rebuttal testimony beginning at line 6 on page 32 through line 25 on page 35. I stand by my rebuttal testimony on this issue and continue to maintain that charging the citizens of Slayton for 98.8 percent of the cost of a substation with substantial excess capacity that they did not request is not fair and is outside the realm of an equitable outcome.

Q. Does Ms. Peterson adjust her proposed total for just compensation as a result of her rebuttal testimony?

A. Yes she does. Shown below is Ms. Peterson's Table 2 from page 46 of her rebuttal testimony.

Table 2
Just Compensation

Value of Property	$3,220,653
Loss of Revenue*	$40,189,171
Meter Integration Expense	Est. $140,000
Continued Service Integration Expense	Est. $15,000
DER Integration Expense	To Be Identified
Stranded Slayton West Substation	$1,131,354
Total	$44,696,178
*Or $3,650,641 per year over 2026-2045	

It is important to consider the magnitude of her proposed compensation in light of the facts of this case.

Q. Do you agree with Ms. Peterson's position on just compensation in this case?

A. No, I do not. As I stated earlier in this surrebuttal testimony, Ms. Peterson listed the annual revenue from sales in Slayton at $2,914,221. Her first year levelized loss of revenue payment of $3,650,641 is 125% of the annual gross revenue. Loss of revenue is supposed to represent **net** loss of revenue (gross revenue less avoidable expenses). Her present value lump sum loss of revenue payment of $40,189,171 is 13.8 times as large as the annual gross revenue from Slayton. According to Ms. Peterson's logic and calculations, over a twenty-year period, Xcel can apparently do nothing to "adjust" its system for loss of Slayton and will actually incur additional expenses.

Additionally, she lists the value of property to be acquired by Slayton to be $3,220,653. This represents facilities that Xcel will no longer own and operate. As such:

- Xcel will no longer be allowed a rate of return on those assets (you don't get return on things you don't own).
- Xcel will no longer have depreciation expense for these facilities.
- Xcel will not need to perform any maintenance on these facilities.
- Xcel will no longer need to provide various services to the customers connected to these facilities.

Her lump sum loss of revenue payment of $40,189,171 is 12.5 times larger than the cost of facilities. Spread over her 20-year payment period, this represents an effective annual payment of $2,009,459. This annual payment of $2,009,459 is an effective annual return to Xcel of 62.4% ($2,009,459 divided by $3,220,653) for 20 years.

Q. How would you summarize your surrebuttal testimony and recommendations in this matter?

A. Xcel is a large diverse vertically-integrated utility that, in service of its customers, constantly adjusts its vast operations to account for changes in its utility service territory and the regulatory and market environments impacting that service. Based on that continuing operational environment, Xcel can reasonably adjust for the loss of a small rural community like Slayton within a five-year period. Additionally, my calculated loss-of-revenue payment of 4.2 mills/kWh is in keeping with the procedures and approach of previous Commission cases as applied to the unique facts of this case. I believe the Commission should conclude, based on the record in this case, that the loss of revenue compensation for Slayton's exit from the Xcel system is no more than 4.2 mills/kWh to be paid out over a five-year compensation period.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

Attachment Description	**Pages**
Attachment L: Rebuttal Testimony of Amy Liberkowski and Schedule, dated Oct. 10, 2025, in Docket No E002/GR-24-320	39
Attachment M: Direct Testimony of Benjamin C. Halama and Schedules, dated Nov. 1, 2024, in Docket No E002/GR-24-320	169
Attachment N: Rebuttal Testimony of Benjamin C. Halama and Schedules, dated Oct. 10, 2025, in Docket No E002/GR-24-320	96

Rebuttal Testimony and Schedule
Amy A. Liberkowski

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-24-320
Exhibit___(AAL-2)

Policy

October 10, 2025

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Schedule

Sales, Customers, Average Usage, Revenue, and Bill Analysis — Schedule 1

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Amy A. Liberkowski. I am the Regional Vice President for Regulatory and Pricing for Northern States Power Company-Minnesota (NSPM or the Company), d/b/a Xcel Energy. In this role, I am responsible for regulatory filings with the utility commissions in Minnesota, North Dakota, and South Dakota, including proceedings related to rates, cost recovery riders, and voluntary customer rate offerings.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes. I submitted Direct Testimony on behalf of the Company, presenting a Company and case overview and addressing certain policy matters.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my Rebuttal Testimony is to provide an overview of our rebuttal case and to respond to the testimony and recommendations of witnesses for the Department of Commerce, Division of Energy Resources (Department), Office of Attorney General – Residential Utilities Division (OAG), Citizens Utility Board (CUB), Xcel Large Industrials (XLI), Energy CENTS Coalition (ECC), Suburban Rate Authority (SRA), Joint Intervenors, and Walmart. I discuss a number of changes that have occurred since our initial filing, many of which relate to issues raised by others, and which form the basis for our rebuttal proposal. I also provide an overview of certain of these parties' recommendations and the Company's response and discuss broader considerations demonstrating the reasonableness of the Company's rebuttal request. Finally, I identify the witnesses who will provide more detailed responses to these parties in Rebuttal Testimony.

Q. HOW IS THE REST OF YOUR REBUTTAL TESTIMONY ORGANIZED?

A. I first address a topic raised by various parties and the public as this case has progressed – the concern regarding the affordability of Xcel Energy's electric service. As I will discuss, the Company works hard to maintain affordable service and, while individual rate components may have risen and would rise again with this request, our customers' overall bills continue to be below the national average. That said, we continue to take affordability concerns seriously and our rebuttal case substantially reduces our request.

Second, I provide an overview of our rebuttal case. As part of that discussion, I highlight some known changes since we filed this case and that are appropriate to reflect in the Commission's final determination of our rate request. I also reply to certain specific recommendations made by parties and discuss the appropriate ratemaking treatment of certain items discussed by those parties.

Finally, I introduce the Company's rebuttal witnesses, identifying the issues they address.

II. AFFORDABILITY, RATES, AND RATE CASE TRENDS

Q. YOU NOTED ABOVE THAT INTERVENORS AND THE PUBLIC HAVE RAISED CONCERNS REGARDING THE AFFORDABILITY OF XCEL ENERGY'S ELECTRIC SERVICE. WHAT IS THE COMPANY DOING TO ADDRESS THESE CONCERNS?

A. To begin with, the Company has always worked hard to ensure our service is reliable, sustainable, and cost effective. Beyond those broader ongoing efforts, however, the Company is taking multiple actions to maintain the affordability of its electric service, particularly to those who feel the greatest energy burden. Company witness Nicholas F. Martin discusses some of those steps in both his Direct and Rebuttal Testimonies, as does Company witness Nicholas N. Paluck. In addition, in this rebuttal filing, the Company has reduced its multi-year rate plan (MYRP) revenue requirement request by over $108 million, or 23 percent, from its Supplemental Direct Filing, as I discuss below and as detailed by Company witness Benjamin C. Halama. The Company understands that rate increases impact everyone, and we work to limit those increases where possible. And while the Company's rates have increased over the past 10 years, there seem to be some fundamental misunderstandings and misperceptions regarding the Company's rates, bills, and rate case trends that I address below.

Q. CAN YOU PROVIDE AN EXAMPLE OF SUCH A MISPERCEPTION?

A. Yes. Department witness Mark Johnson testifies that Xcel Energy's rates have increased faster than utility peers. Implicit in this observation is a conclusion that the Company's service has become more costly than our peers' costs. As I discuss below, I disagree with Department witness Johnson's conclusions and there are two areas in which I disagree with Department witness Johnson's data.

First, I disagree with Department witness Johnson's suggestion that Xcel Energy's rates have increased by $2.2 billion since 2011.[1] Department witness Johnson's Table 1 shows that this is not the case, as it indicates that the

[1] Ex. DOC-___ at 19–20 (Johnson Direct).

Commission has authorized $818.3 million in rate increases since 2011, far less than Department witness Johnson states.

Further, the numbers Department witness Johnson points to are revenue deficiencies, not an increase in the total cost of providing service. Over the nearly 20-year period between our 2005 rate case[2] to the conclusion of our 2024 plan year,[3] our authorized revenue requirement increased by $1.3 billion, about 60 percent of what Department witness Johnson suggests. Over this time, our overall revenue requirement has grown at an average rate of 2.6 percent annually, similar to the 2.5 percent annual rate of inflation.[4]

Second, Department witness Johnson states that Xcel Energy's rates have grown more quickly than other utilities in the state. But even Department witness Johnson's own Schedule MAJ-D-3 indicates that is not true, showing that Xcel Energy's rates have increased more slowly than rates for Minnesota Power.

Q. BEYOND THESE SPECIFIC ISSUES WITH DEPARTMENT WITNESS JOHNSON'S TESTIMONY, DO YOU HAVE ANY OVERARCHING CONCERNS WITH HIS OVERALL ANALYSIS?

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[2] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Findings of Fact, Conclusions of Law, and Order; Order Opening Investigation at 46, Docket No. E-002/GR-05-1428 (Sept. 1, 2006). The authorized revenue requirement was $2,213,805,000.

[3] *In the Matter of the Application by Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in the State of Minnesota*, Revised Final Rates Compliance at 3, Docket No. E-002/GR-21-630 (Nov. 14, 2023). The authorized revenue requirement was $3,540,380,000.

[4] According to the Bureau of Labor Statistics, $1 in 2005 was worth $1.56 in 2024. https://www.bls.gov/data/inflation_calculator.htm.

A. Yes. Department witness Johnson's analysis of the data is incomplete and, as a result, misleading. A fuller assessment, which I discuss below, demonstrates that the trends in the Company's rate cases and rates are largely driven by reductions in sales, which Department witness Johnson does not consider. Failing to do so paints a fundamentally incomplete picture of the actual costs the Company's customers pay for service. It also ignores the impact of the substantial efforts the Company takes to drive energy efficiency—which by definition reduces electric sales—consistent with Minnesota's energy goals.[5] When the full context is evaluated, the data demonstrates that our customers' *bills* have grown more slowly than other utilities.

A. Impact of Sales on Rates

Q. WHAT IS THE RELATIONSHIP BETWEEN SALES, REVENUES, AND BILLS?

A. At a simple level, our rates are calculated by dividing our authorized cost recovery over our sales:

$$\frac{Authorized\ Cost\ Recovery}{Sales} = Rates$$

Rates can increase if costs increase, if sales decrease, or if costs increase faster than sales. Notwithstanding this fundamental relationship between costs, sales, and rates, Department witness Johnson's analysis does not consider the Company's sales at all.

[5] Minn. Stat. § 216C.05, Subd. 2(1).

Q. How do sales impact rates?

A. Sales impact rates because the Company recovers its cost of providing service over the number of units it sells. If the number of units drops, the Company will need to increase rates to recover the same costs over fewer units of sale. If, on the other hand, its sales go up, the Company can recover its costs over greater units of sale. To provide a simple example, if the utility needs to recover $1,000 in costs and expects to sell 1,000 kWh of energy, a rate based purely on energy sales would be set at $1 per kWh. If the amount of kWh sold decreased to 900 kWh, two things would happen. First, the utility would receive $900 in actual revenues, resulting in a $100 revenue deficiency, which could trigger a rate case filing.

Second, when rates are reset, the $1,000 in revenue requirements must be collected over a smaller number of kWh – all else held equal in this example,[6] a reduction of 100 kWh will increase rates from $1 per kWh to $1.11 per kWh – even though the cost of providing service has not changed.

Q. What happens when a utility experiences declining sales?

A. When a utility that experiences declining sales files a rate case, the Commission will set just and reasonable rates during the test year. And the next year, that utility would not be recovering its authorized revenues because its sales have decreased again. In order to recover its previously determined cost of service—before accounting for inflation or wage growth—the utility would need to file another rate case.

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[6] In the real world, a reduction in sales would reduce some variable costs such as fuel, and this simple example ignores the effects of inflation and wage-growth on the Company's costs from one year to the next.

Q. HOW HAVE XCEL ENERGY'S SALES CHANGED?

A. Xcel Energy's sales have decreased by, on average, 1.03 percent each year from 2014 to 2024.[7] While actual sales volumes fluctuate each year, in 2024 Xcel Energy sold approximately 10 percent fewer kWh than in 2014.

Q. HOW DO CHANGES IN XCEL ENERGY'S SALES COMPARE TO OTHER UTILITIES?

Over this time period, Xcel Energy's sales have decreased substantially more than the average for national electric utilities, Minnesota electric utilities, and Upper Midwest electric utilities, as described in Table 1:

Table 1
Comparison of Annual Change in Sales[8]

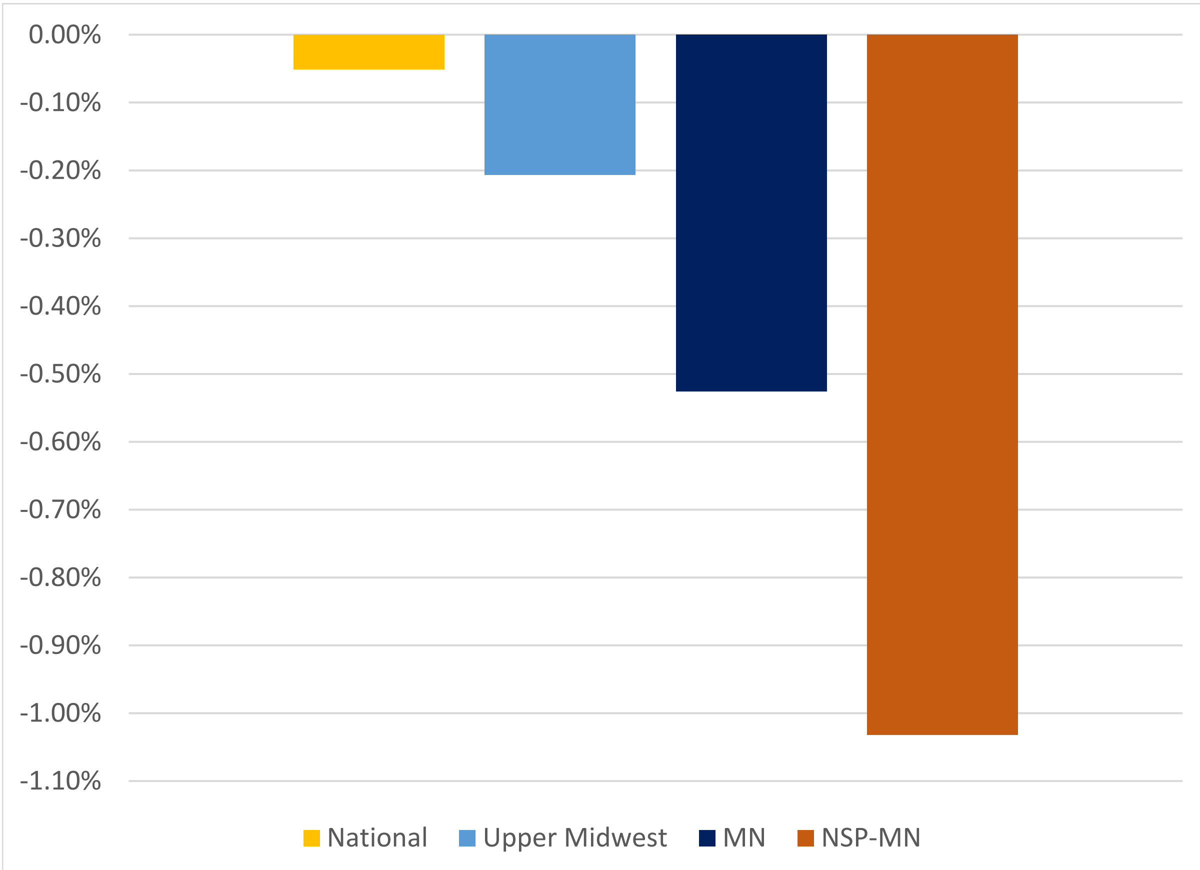
2014-2024 Compound Annual Growth Rate	NSP-MN	National	MN	Upper Midwest
Sales				
Residential	-0.12%	0.24%	-1.36%	-0.05%
Commercial	-1.21%	-0.06%	-0.94%	0.00%
Industrial	-1.77%	-0.54%	-0.22%	-0.63%
Retail	-1.03%	-0.05%	-0.53%	-0.21%

Figure 1 below shows Xcel Energy's sales have declined at an annual rate 20 times greater than sales nationally, and 5 times greater than the upper Midwest.

[7] Exhibit___(AAL-2), Schedule 1A. I have selected the timeline of 2014 to 2024 in response to Department witness Johnson because 2014 was the test year of the first Multi-Year Rate Plan, and because 2024 is the most recent year with full data from the EIA.

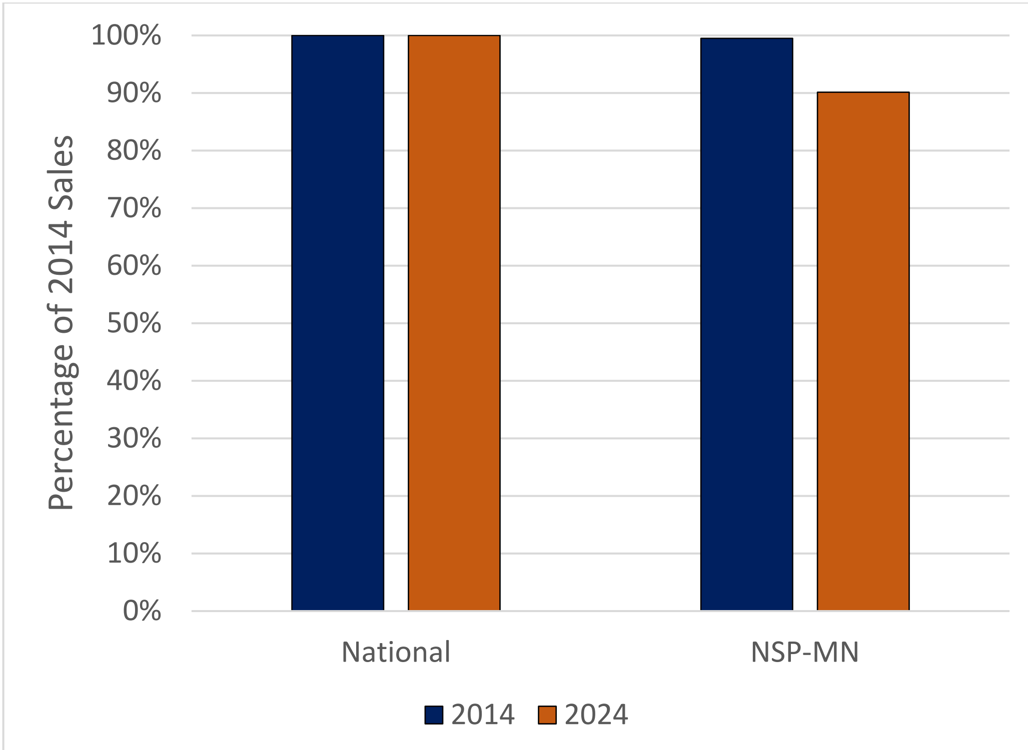
[8] *Id.* The comparison groups for Tables 1 through 4 of my testimony include: (1) all national IOUs; (2) other (non-NSP) Minnesota IOUs; and (3) IOUs located in the states that make up our Upper Midwest system, including MN, ND, SD, WI, and MI. These tables are based on data from the Energy Information Administration Form EIA-861M (formerly EIA-826) detailed data. The underlying data set is provided as Schedule 1A.

Figure 1
Comparison of Annual Change in Retail Sales
2014 - 2024



As Figure 2 below indicates, over the 10-year period, national electric utilities have reduced their total sales by approximately 0.5 percent, while Xcel Energy's sales have declined by almost 10 percent.

Figure 2
Comparison of Sales Decline[9]



Q. WOULD THESE SALES REDUCTIONS LEAD TO LOWER COSTS FOR THE UTILITY BECAUSE CUSTOMERS ARE LEAVING THE SYSTEM?

A. No. In fact, while the Company has experienced this sales decline, it has done so despite having customer count growth that is larger than other utilities.[10] The Company has continued to incur the cost of adding customers (new meters, lines, etc.).

Q. HOW DOES THIS EXAMPLE APPLY TO THE REAL WORLD?

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[9] Schedule 1A.
[10] Exhibit___(AAL-2), Schedule 1B.

A. Xcel Energy's sales have been dropping steadily since 2014, while national electric utilities sales have been basically flat. Department witness Johnson's implication that Xcel Energy is different than other utilities is correct. But it is different from other utilities because it is experiencing a significantly greater reduction in sales, while simultaneously serving more customers – meaning an even bigger drop in sales per customer than other utilities have experienced.

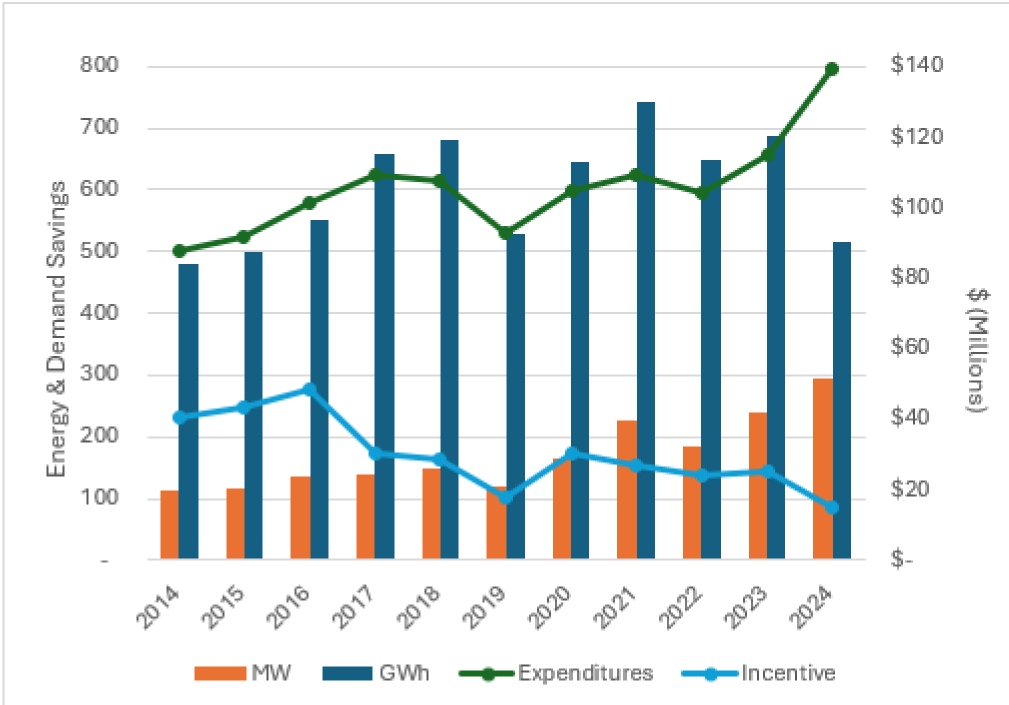
Q. WHAT IS CAUSING XCEL ENERGY TO HAVE A REDUCTION IN SALES?

A. One reason Xcel Energy has seen a significant reduction in sales is our commitment to conservation and our efforts through the Energy Conservation and Optimization (ECO) program and its predecessor the Conservation Improvement Program (CIP).

From 2014 to 2024, Xcel Energy steadily increased its level of investments in conservation, from approximately $90 million in 2014 to more than $140 million in 2024.[11] This has led to continued energy savings measured in both MW and GWh, as displayed in Figure 3:

[11] Xcel Energy 2024 Status Report and Associated Compliance Filings at 4, Docket No. E,G002/CIP-23-92 (Apr. 1, 2025).

Figure 3
Xcel Energy Conservation Performance 2014-2024[12]



In 2024, our conservation efforts achieved over 516 GWh of electric savings, representing 1.90 percent of sales and $411 million in net benefits for our electric customers.[13]

Q. HOW DO XCEL ENERGY'S CONSERVATION EFFORTS COMPARE TO OTHER UTILITIES?

A. It is difficult to compare conservation efforts and performance across utilities given the wide variety of state regulatory structures and individual program design. But one point of comparison is the average electricity usage per customer, which demonstrates that Xcel Energy is dramatically outperforming

[12] *Id.* These figures represent annual energy savings.
[13] *In the Matter of the Petition of Northern States Power Company for Approval of an Electric Conservation Improvement Program Adjustment Factor*, Petition at 1, Docket No. E002/M-25-50 (Apr. 1, 2025).

its peers in reducing this number. As described in Table 2, from 2014 to 2024, national electric utilities have reduced average usage per customer by 0.66 percent each year, on average. Xcel Energy has reduced its average usage per customer by 1.97 percent each year, more than three times the national average.

Table 2
Comparison of Annual Change in Average Usage[14]

2014-2024 Compound Annual Growth Rate	NSP-MN	National	MN	Upper Midwest
Average Usage				
Residential	-1.11%	-0.41%	-1.84%	-0.74%
Commercial	-1.81%	-0.38%	-2.11%	-0.76%
Industrial	-2.68%	-0.35%	-0.92%	7.43%
Retail	-1.97%	-0.66%	-1.13%	-0.89%

Q. WHAT IS YOUR OVERALL CONCLUSION ABOUT THE IMPACT OF SALES ON RATES?

A. Our customers benefit from reduced sales because they consume less electricity, and we can potentially avoid the costs of investments that would be needed to serve higher load. It does, however, have an impact on rates that cannot be ignored. Simply focusing on these rate increases, without this context, is an incomplete analysis. Trends related to revenues compared to other utilities support my conclusion that reductions in sales are impacting Xcel Energy's rates and its need for rate increases.

Q. HOW DO XCEL ENERGY'S REVENUES COMPARE TO OTHER UTILITIES?

A. From 2014 to 2024, Xcel Energy's revenues have increased considerably less than national electric utilities, Minnesota electric utilities, and electric utilities in the Upper Midwest.

[14] Exhibit___(AAL-2), Schedule 1C.

Table 3
Comparison of Annual Change in Utility Revenue[15]

2014-2024 Compound Annual Growth Rate	NSP-MN	National	MN	Upper Midwest
Revenues				
Residential	2.78%	3.05%	3.02%	2.82%
Commercial	1.61%	1.58%	3.13%	2.18%
Industrial	0.67%	0.75%	4.17%	0.82%
Retail	1.87%	2.18%	3.68%	2.18%

Against all comparison groups, Xcel Energy revenues have increased at the slowest rate over the relevant time period.

I also note that Xcel Energy's EIA revenue data does not include bill credits that customers receive for their participation in our Community Solar Gardens program or our low-income discounts. If those credits were included, our revenues would be lower still (because the credits reduce the amount of revenue received from customers).

B. Trends in Bills

Q. IS THE TREND IN XCEL ENERGY RATES NEGATIVELY IMPACTING CUSTOMERS?

A. No, at least not to the extent suggested by Department witness Johnson. That is the case because, despite the challenges of declining sales, the Company has managed to limit the overall impact on customer bills.

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15 Exhibit___(AAL-2), Schedule 1D. The revenue data included in Table 3 includes all retail revenues, including both base rate and rider revenues.

Q. IS IT IMPORTANT TO CONSIDER BILLS WHEN EVALUATING IMPACTS ON CUSTOMERS?

A. Yes, in fact bill impacts may be the *most* important factor to consider if one is focused on affordability. Bills are the costs that customers actually pay. In addition, for the reasons discussed above, implementing conservation policies results in overall bill savings, even if it puts upward pressure on rates. The State's support of the Company's robust conservation efforts means there will be somewhat higher *rates* in part due to lower customer *bills* from what they would be absent these conservation programs.

Q. HOW HAVE XCEL ENERGY BILLS CHANGED COMPARED TO OTHER UTILITIES?

A. From 2014 to 2024, Xcel Energy's bills have grown substantially slower than the national average of electric utilities, other electric utilities in Minnesota, and other utilities in the Upper Midwest.[16]

Table 4
Comparison of Annual Changes in Average Bills[17]

2014-2024 Compound Annual Growth Rate	NSP-MN	National	MN	Upper Midwest
Bills				
Residential	1.76%	2.38%	2.52%	2.11%
Commercial	0.99%	1.25%	1.91%	1.41%
Industrial	-0.25%	1.64%	3.43%	9.00%
Retail	0.90%	1.57%	3.05%	1.47%

[16] Exhibit___(AAL-2), Schedule 1E.
[17] Schedule 1E

Q. WHAT DOES THIS INFORMATION MEAN?

A. It means that the actual monthly bills paid by our customers have been increasing considerably more slowly than our peer utilities since 2014. This is true across every rate class – residential, commercial, and industrial. Overall, the Company's bills have increased at a rate that is about one-third less than other Minnesota utilities over a decade, and even less than other Upper Midwest and National utilities. I believe this context gets lost when the focus shifts to rates or rate cases, but it means Xcel Energy has outperformed other utilities in limiting customer bill increases and maintaining affordability for our customers.

C. Multi-Year Rate Plan Impacts

Q. DEPARTMENT WITNESS JOHNSON ALSO CONTENDS THAT XCEL ENERGY'S RATES HAVE INCREASED MORE QUICKLY BECAUSE OF MYRPS. DO YOU AGREE?

A. No. In particular, I do not agree with his statement that the purpose of MYRPs is fewer rate-case related rate increases.[18] The effect of the MYRP statute is to require fewer rate case *filings*, even though each filing will necessarily include multiple years of rate changes. I believe that the implementation of the MYRP has been beneficial to our customers. Specifically, the Company's MYRPs have allowed us to recover the costs of providing service using a more efficient administrative process and, by setting rates for more than a single year, these cases allow the Company to manage its business in line with the approved rates. It is also important to note that the Commission has complete authority to review rate increase requests over each year of a MYRP and has been very rigorous in doing so.

[18] Ex. DOC-___ at 21 (Johnson Direct)

Q. HAS THE MYRP STATUTE RESULTED IN FEWER RATE CASE FILINGS?

A. Yes. As Department witness Johnson notes, before the MYRP legislation was passed, the Company filed a new rate case approximately every two years. Since the passage of the MYRP statute, the Company has completed four rate cases over twelve years. Under our previous cadence, we would have filed six rate cases over that time period, saving both our customers and regulators the cost of filing and reviewing those cases.

Q. HAVE THE COMPANY'S MYRP FILINGS RESULTED IN UNREASONABLE RATES?

A. No. The Commission has carefully reviewed each of the Company's MYRP filings and approved the resulting rates. And, as I discussed above, this Commission review has led to rates that, coupled with the Company's conservation efforts and the declining use per customer, has kept Xcel Energy's bill increases lower than other utilities.

III. THE COMPANY'S REBUTTAL CASE

A. Overview

Q. IT HAS NOW BEEN NEARLY A FULL YEAR SINCE THE COMPANY FILED THIS RATE CASE. HAS THE COMPANY EXAMINED HOW ANY CHANGES OVER THIS PAST YEAR MAY HAVE AFFECTED THE COMPANY'S INITIAL FILING AND ITS REQUESTED REVENUE REQUIREMENT?

A. Yes. In presenting our rebuttal case, the Company has analyzed and considered Intervenor Direct Testimony recommendations as well as the effect of regulatory decisions and other actions that have occurred since the Company's Initial or Supplemental Direct filings on the Company's revenue requirements in both the 2025 test year and the 2026 plan year. Where reasonable and appropriate, we have incorporated adjustments to our revenue requirement request to acknowledge these changed circumstances.

Q. PLEASE PROVIDE EXAMPLES OF INTERVENOR RECOMMENDED ADJUSTMENTS DUE TO DEVELOPMENTS SINCE THE INITIAL FILING THAT THE COMPANY HAS INCORPORATED INTO ITS REBUTTAL CASE.

A. I will highlight three such items. First, as Company witness Mark P. Moeller discusses, the Commission has now approved life extensions for both the Monticello and Prairie Island nuclear plants in the Company's 2024-2040 Integrated Resource Plan docket (Docket No. E002/RP-24-67). The Department recommended that, given that approval, the Company revise its requested depreciation expense to acknowledge these life extensions. The Company is aware of no opposition to the Department's recommendation and agrees that such an adjustment in this case is reasonable. Extending the depreciable lives of these plants results in a total reduction to depreciation expense of nearly $70 million in both 2025 and 2026.

Similarly, the Commission has now also issued its Order in the Company's Triennial Nuclear Decommissioning proceeding (Docket No. E002/M-24-394). That Order resulted in a reduction in the annual decommissioning accrual of approximately $17.7 million in 2025 and 2026. Company witness Halama incorporates both the depreciation expense and decommissioning accrual reductions into his rebuttal revenue requirements, lowering the Company's request.

Finally, as Company witness Halama discusses, the Company now has more recent capacity auction revenue and bilateral capacity contract revenue information available to inform a more current baseline of capacity revenues for setting rates. The Department recommended adjusting the 2025 and 2026 baseline revenues to reflect more current information and the Company agrees, subject to true-up in the Company's annual capacity tracker filings. As shown in Company witness Halama's Rebuttal Testimony and Schedules, this adjustment substantially reduces the 2025 and 2026 baseline revenue requirements.

Q. HAS THE COMPANY ALSO INCORPORATED ANY UPDATES TO ITS TEST YEAR AND PLAN YEAR REVENUE REQUIREMENTS?

A. Yes. Consistent with the Company's Direct Testimony, the Company has updated certain items to reflect more current information. For example, Company witness Benjamin S. Levine provides the Company's updated 2026 sales forecast and Company witness Halama reflects that updated forecast in his rebuttal revenue requirements. This updated forecast provides the most current and accurate revenue forecast on which to set base rates for 2026, which will also then serve as the proper baseline for the sales true-up.

At the same time, the Company has provided other updates as indicated in our Initial Filing that we have not included in our revised revenue requirements request. For instance, Company witness Todd A. Wehner indicated in our Initial Filing that he would update our cost of debt. In his Rebuttal Testimony, Company witness Wehner explains that our cost of long-term debt increased from our Initial Filing but by a small amount that the Company has not incorporated into its rebuttal revenue requirement.

Q. IS THE COMPANY ACCEPTING OTHER INTERVENOR RECOMMENDATIONS THAT IMPACT THE COMPANY'S REBUTTAL REVENUE REQUIREMENT?

A. Yes. Intervenors proposed certain adjustments that the Company agrees with in concept and has reflected adjustments for those items as well. As an example, the Company agrees with the Department that it is reasonable to write-off obsolete inventory related to Sherco Unit 1 over a three-year period, rather than a single year (although the Company proposes the three-year period coincide with the Company's proposed amortization of rate case expenses, so beginning in the test year). Other Company witnesses address certain of these adjustments and Company witness Halama's Rebuttal Testimony provides a full accounting of these and other changes the Company has incorporated into its rebuttal revenue requirements request.

Q. DOES THE COMPANY'S REBUTTAL CASE ALSO INCLUDE SOME KNOWN COSTS NOT INCLUDED IN ITS INITIAL FILING?

A. It does, but these changes are minor in comparison to the reductions included in the Company's rebuttal case. For example, in our Initial Filing we noted that the Commission's approval of proposed IT costs associated with the Transportation Electrification Plan had not been fully reflected in the cost of service. Company witness Halama has now incorporated the approved expenses, $2.4 million in capital and $0.9 million in O&M, into our rebuttal revenue requirement.

Q. WHY IS THE COMPANY INCORPORATING THESE ADJUSTMENTS IN ITS REBUTTAL CASE?

A. The Commission's task in a rate case is to set rates that best reflect the utility's reasonable cost of service and its expected revenues, for the time period they will be in effect. Such rates will be just and reasonable for our customers and for the Company. In this case, given the passage of time since the Company's Initial Filing, the Company, Commission, and parties have additional information on the Company's reasonable cost of service and expected revenues, so it is appropriate to use that information in setting just and reasonable rates.

Q. TAKEN AS A WHOLE, WHAT IS THE IMPACT OF THE UPDATES AND ANY OTHER AGREED UPON ADJUSTMENTS TO THE COMPANY'S INITIAL REVENUE INCREASE REQUEST?

A. While Company witness Halama presents the Company's rebuttal revenue requirement request, a comparison of our rebuttal case to our initial request and to our supplemental request is presented in Table 5, below and demonstrates the substantial reductions the Company has incorporated into that request.

Table 5
MYRP Revenue Requirements ($s in millions)

	2025	2026	Total
Initial Request	$353.3 9.6%	$137.4 3.6%	$490.7 13.2%
Supplemental Request	$344.3 9.4%	$129.3 3.3%	$473.6 12.7%
Rebuttal Request	$208.4 5.8%	$156.9 4.2%	$365.3 10.0%
Increase/(Decrease) from Initial to Rebuttal	($144.9) (3.8%)	$19.5 0.6%	($125.4) (3.2%)

Q. DOES THIS SIGNIFICANT REDUCTION IN THE COMPANY'S REVENUE REQUIREMENT INDICATE THAT THE COMPANY INFLATED ITS INITIAL FILING REQUEST?

A No. The Company does not file cases requesting more than it believes is necessary to meet the cost of providing safe, reliable, and environmentally sound electric service, in conformance with State policy. However, in this case substantial new information has been developed, or regulatory rulings received, that can now be incorporated and have informed the Company's request. Incorporating that information into this rebuttal request lessens the impact of this case on our customers, while resulting in just and reasonable rates for both the Company and our customers.

B. Specific Intervenor Financial Recommendations

Q. ARE THERE SPECIFIC INTERVENOR FINANCIAL RECOMMENDATIONS YOU WISH TO ADDRESS?

A. Yes. While Company witness Halama and the Company's subject matter experts address most of the Intervenors' recommended financial adjustments, a couple of those recommendations raise ratemaking and policy-related concerns I believe should be considered and that I address below.

1. Sherco 3 Rate Base Adjustment

Q. WHAT WAS PROPOSED BY INTERVENORS REGARDING CERTAIN SHERCO 3 INVESTMENTS INCLUDED IN THE COMPANY'S RATE BASE?

A. OAG witness Shoua Lee recommended reducing the Company's 2025 and 2026 rate base amounts for a portion the Company's costs of restoring Sherco 3 following a catastrophic event at the plant in 2011. While insurance proceeds covered the overwhelming majority of the restoration costs, and those insurance proceeds were credited to rate base well over a decade ago, insurance did not cover a portion of those costs. That unrecovered balance, approximately $5.5 million, was included in the Company's rate base in its 2013 rate case, Docket No. E002/GR-13-868, and has continued to be included in rate base in each succeeding case. Due to the passage of time, just $2.4 million remains in rate base for the 2025 test year and $2.1 million in the 2026 plan year. OAG witness Lee recommends excluding those amounts from rate base, arguing that the Commission has now found Xcel Energy was imprudent in its operation and maintenance of Sherco 3, leading to the catastrophic event.

Q. DOES THE COMPANY AGREE WITH OAG WITNESS LEE'S RECOMMENDATION?

A. No. As I noted, the Commission authorized the Company to include these costs in rate base in the 2013 rate case and these costs were similarly included in rate base in the Company's two subsequent rate cases. OAG witness Lee's recommendation seeks to overturn those prior decisions, years after they were first implemented. This retroactive change to the manner in which the Company has recovered these costs should be rejected and the Commission should continue to implement its 2013 rate case decision.

2. *Riverside Generating Unit*

Q. WHAT WAS PROPOSED BY INTERVENORS IN RELATION TO THE RIVERSIDE GENERATING UNIT?

A. Department witness Johnson recommended removing the Riverside Generating Unit from the Company's revenue requirement, beginning May 1 of the 2025 test year, through May of the 2026 plan year. He makes this recommendation due to a mechanical failure in the Riverside steam generator on April 1, 2025 that caused the plant to go off-line, noting that the plant is not expected to resume operations until June 1, 2026. Department witness Johnson bases his recommendation on his conclusion that the plant is not "used and useful" during the time it is off-line.

Q. DOES THE COMPANY AGREE WITH REMOVING THE RIVERSIDE GENERATING UNIT AS PROPOSED BY DEPARTMENT WITNESS JOHNSON?

A. The Company does not agree, for several reasons. First, the plant was undeniably used and useful for the first part of the 2025 test year and will be returned to service for the majority of the 2026 plan year. For that reason, the Riverside Generating Unit should remain in the Company's rate base. Second, a determination that the plant continues to be used and useful is demonstrated by the fact that it was included in the 2025-2026 MISO capacity auction and generated substantial capacity revenues, as discussed by Company witness Nicholas J. Detmer in his Rebuttal Testimony. In fact, as shown in Department witness Johnson's own Schedule 11, for the time period covered by his recommendation, those capacity revenues are forecasted to be approximately \$26 million.[19] Finally, the labor O&M costs Department witness Johnson recommends removing will be incurred as the Company works to return the plant to service.[20]

Q. WOULD REMOVING THE RIVERSIDE GENERATING UNIT FROM THE TEST AND PLAN YEARS AS PROPOSED BY DEPARTMENT WITNESS JOHNSON BE APPROPRIATE RATEMAKING TREATMENT FOR THIS FACILITY?

A. Not as he has proposed. Department witness Johnson proposes to not only deny the Company recovery for the plant, but to then credit customers with the

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[19] Ex. DOC-___, MAJ-D-11 at 2.
[20] Id.

capacity revenues the Company receives due to the plant over that same period that the costs would not be included in rates. I am aware of no ratemaking principle that supports such a result.

Q. IS THERE AN ALTERNATIVE TO DEPARTMENT WITNESS JOHNSON'S RECOMMENDATION?

A. Yes. While the Company disagrees with Department witness Johnson's recommendation, if the Commission determines to remove all costs associated with the Riverside plant for the period of time recommended by Department witness Johnson, then the Company should be allowed to retain all revenues it receives due to the plant during the time period of that disallowance.

Q. DOES THE COMPANY RECOMMEND THIS ALTERNATIVE AS ITS PREFERRED APPROACH TO RESOLVING THIS ISSUE?

A. No. The Company continues to believe the more sound approach is to include both the costs and revenues associated with this plant, as originally proposed. The plant is used and useful to ratepayers, as demonstrated by the substantial capacity revenues it generates.

3. Sherco 3 and King Remaining Lives

Q. DID ANY INTERVENOR PROVIDE A RECOMMENDATION TO CHANGE THE REMAINING LIVES OF THE COMPANY'S SHERCO 3 AND KING GENERATING PLANTS?

A. Yes. Based on the Commission's decision in the Company's 2024-2040 IRP to approve shortening the operating lives of the Sherco 3 and King coal plants, the Department recommends that the Commission match the depreciable lives with operating lives for those plants, beginning with the start of the 2025 test year.

Q. DOES THE COMPANY AGREE WITH THIS RECOMMENDATION?

A. Not at this time. As Company witnesses Moeller and Halama also discuss in their Rebuttal Testimonies, shorter depreciable lives would increase annual depreciation expense, which increases the overall revenue requirement in the 2025 test year and 2026 plan year. The Company's proposed regulatory asset treatment for Sherco Unit 3 and the King plant best aligns with state energy policy directives and the Commission's recently established framework for the ratemaking treatment of early retirement of generating resources issued in May 2025 in Docket No. E002,E015,E017/CI-23-375,[21] while also ensuring the Company has the opportunity to recover its prudently incurred costs related to these resources. As discussed in the Rebuttal Testimony of Company witness Halama, implementing accelerated depreciation with final rates as proposed by the Department would likely prevent the Company from having the opportunity to recover its prudently incurred costs related to these generation resources, because the accelerated depreciation expense is not included in interim rates.[22] Again, fundamental ratemaking principles support allowing the Company a reasonable means of recovering such prudently incurred costs, particularly where the decision to retire these coal plants early was made in support of state clean-energy policy objectives.

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[21] *In re Comm. Inquiry into the Ratemaking Treatment for Early Retiring Generating Facilities Owned by Regulated Elec. Utilities,* Docket No. E002, E015, E017/CI-23-375, ORDER ESTABLISHING FOUR-TIERED APPROACH FOR RATEMAKING TREATMENT OF EARLY RETIRING GENERATING FACILITIES (May 14, 2025).

[22] At the time of the Company's initial filing in this proceeding, a decision regarding the ratemaking treatment of early retired generation resources was still pending in Docket No. E002, E015, E017/CI-23-375.

Under the tiered framework established by the Commission in Docket No. E002,E015,E017/CI-23-375, the Commission concluded that accelerated depreciation may not be appropriate when it could result in affordability concerns or significant rate impacts. The purpose of tier three—the creation of a regulatory asset with return—is to minimize cost to customers while allowing utility recovery of prudently invested capital retiring early due to environmental regulation.

For all of these reasons, the Company continues to support the proposed regulatory asset treatment for the Sherco 3 and King plants as outlined in the Direct Testimonies of Company witnesses Moeller and Halama in this case.

4. *Wildfire Mitigation*

Q. DID ANY INTERVENORS ADDRESS THE COMPANY'S PROPOSED WILDFIRE MITIGATION ACTIVITIES?

A. Yes. Department witness Eric Borden and Joint Intervenors witness William D. Kenworthy both addressed the Company's proposed wildfire mitigation activities. Department witness Borden noted that the Company has brought forward assessments of wildfire risk that are "a solid foundation," and he supports certain aspects of the Company's proposals.[23] Joint Intervenor witness Kenworthy found the Company's introduction of its wildfire mitigation activities in this proceeding to be "a necessary and constructive step" given "[w]ildfire risk is a serious public-safety concern" and that wildfire mitigation is appropriately considered to be "core [to the Company's] obligation to provide clean, safe reliable and affordable service."[24] Ultimately, Joint Intervenors

[23] Ex. DOC-__ at 3 (Borden Direct).
[24] Ex. JI-__ at 16 (Kenworthy Direct).

witness Kenworthy "commend[s] Xcel [Energy] for bringing this issue to the Commission with a concrete proposal and for beginning to build a Minnesota-specific record on where the risks lie and how operations and investments will adapt."[25]

Q. DID THE DEPARTMENT AND JOINT INTERVENORS SUPPORT THE ENTIRETY OF THE COMPANY'S WILDFIRE MITIGATION PROPOSAL?

A. No. The Department supports certain aspects of the Company's proposal but disagrees with others. Company witnesses Paul J. McGregor and Kelly A. Bloch respond to Department witness Borden, explaining the Company's 2025 test year and 2026 plan year wildfire mitigation activities represent a foundational scope of work needed to mitigate against the risk of utility equipment contributing to a wildfire.

Joint Intervenor witness Kenworthy recommends the Commission defer action on the 2025 test year and 2026 plan year activities until they are addressed in a forthcoming Integrated Distribution Plan (IDP).[26]

Q. WHAT IS YOUR RESPONSE TO JOINT INTERVENOR WITNESS KENWORTHY?

A. First, Joint Intervenor witness Kenworthy's recommendation that the Commission not permit cost recovery in this proceeding for work that is directed at what he characterizes is "a serious public-safety concern"[27] is not the right policy direction for Minnesota. As Company witness McGregor discusses, data provided by the Department shows that Minnesota has quantified wildfire

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[25] Ex. JI-__ at 17 (Kenworthy Direct).
[26] Ex. JI-__ at 20 (Kenworthy Direct).
[27] Ex. JI-__ at 16 (Kenworthy Direct).

risk similar to Hawaii, a state that suffered from devastating wildfires in the relatively recent past. Pursuing the foundational work put forward by the Company is a reasonable response to what is unfortunately a growing risk in our physical environment.

Second, I disagree that wildfire costs need to be assessed in a forthcoming IDP as a precondition for cost recovery. The Company is presently in a rate case and seeks recovery of costs actively being incurred, which are directed at mitigating a present risk. IDPs are on their own cadence, that, in this instance, does not align with the Company's rate request. Further, as discussed in our last IDP, the IDP is really for presenting a long-term plan and vision for the distribution grid, not presentation of information inherent in the ratemaking process:

> The IDP presents a long-term plan and vision for the distribution grid, and a five-year year action plan that aligns with our budget forecast. We file a comprehensive IDP every other year, with certain baseline financial information (including an updated five-year budget forecast) and non-wires alternatives analysis provided annually. By contrast, a rate case requests cost recovery of near-term investments – most recently for the years 2022-2024 – and includes information inherent in the ratemaking process like cost of service, capital additions, and revenue requirements, which are not reflected in the IDP. The timing of rate case filings is determined based on internal analyses of our financial position and other factors; there is typically no predetermined or set schedule for rate case filings.[28]

Q. IS THE COMPANY WILLING TO MAKE FUTURE WILDFIRE-SPECIFIC FILINGS?

A. Yes. Company witness McGregor explains the Company can collaborate with interested stakeholders to identify an appropriate proceeding in which to present a formalized wildfire mitigation plan. But while that occurs, the

[28] In the Matter of Xcel Energy's 2023 Integrated Distribution Plan, Docket No. E002/M-23-452, 2023 Integrated Distribution Plan at 25-26 (Nov. 1, 2023).

Commission should approve the foundational work presented for the 2025 test year and 2026 plan year.

Q. COULD THAT FILING BE PAIRED WITH A CHANGE TO HOW WILDFIRE COSTS ARE RECOVERED?

A. Yes. The Company is proposing to recover the 2025 test year and 2026 plan year wildfire costs through base rates. A future proceeding considering a wildfire mitigation plan also could consider a different form of cost recovery. Rider recovery could be advantageous for such costs (in comparison to base rates) in terms of increased transparency and more closely tying costs recovered in rates to those actually incurred for particular projects.

C. Multi-Year Rate Plan Features

Q. DID INTERVENORS RAISE CONCERNS WITH THE SPECIFIC MYRP ISSUES YOU ADDRESSED IN DIRECT TESTIMONY?

A. Largely, no, which I believe reflects the fact that our MYRP features have now been in place for several years and have resulted in just and reasonable rates for our customers. However, the Department has recommended a change to the property tax true-up which has been in place since the Company's 2015 rate case. The Department recommends changing the true-up by implementing an asymmetrical cap that could prevent the Company from recovering its full property tax expense. The Company disagrees with this recommendation, as further discussed by Company witness William T. Kowalowski.

D. Summary

Q. PLEASE SUMMARIZE THE COMPANY'S REBUTTAL CASE.

A. The Company provides a comprehensive response to the concerns raised by Intervenors in this proceeding. While there appears to be broad agreement on the basic MYRP features, Intervenors recommend a number of financial adjustments to the test year and plan year. The Company has analyzed those recommendations, considered new information (including new regulatory decisions), and proposes significant reductions to its initial revenue requirements request that result in just and reasonable rates for our customers.

IV. INTRODUCTION OF REBUTTAL WITNESSES

Q. PLEASE INTRODUCE THE WITNESSES PROVIDING REBUTTAL TESTIMONY FOR THE COMPANY IN THIS PROCEEDING.

A. In addition to my Rebuttal Testimony addressing policy issues, the following Company witnesses are also providing Rebuttal Testimony:

- *Benjamin C. Halama* responds to certain revenue requirement and individual rate base and expense matters raised by various parties and presents the Company's overall rebuttal revenue requirements request;
- *Todd A. Wehner* addresses capital structure and cost of debt issues;
- *Joshua C. Nowak* responds to Intervenor witnesses on cost of equity and capital structure issues;
- *Gregory J. Robinson* replies to certain recommended adjustments for dues and employee award expenses;
- *Benjamin S. Levine* provides the Company's updated 2026 sales forecast, as indicated in his Direct Testimony;
- *Marty D. Mensen* responds to Intervenor recommendations regarding capital and O&M expenses related to Distribution's projects and

programs, and the proposed updates to the ATO/MTO Dual Feeder tariff.

- *Kelly A. Bloch* specifically responds to Intervenor testimony regarding Distribution wildfire investments and expenditures;
- *Diedra K. Howard* responds to witness testimony regarding the Company's Customer Care organization and bad debt expense;
- *Nicholas J. Detmer* addresses the Prairie Island capacity accreditation issue referred to this proceeding by the Commission after the date of our Initial Filing and discussed by the Department in its Direct Testimony;
- *David J. Berklund* responds to Intervenor testimony on Transmission O&M expenses;
- *Randy A. Capra* replies to Intervenor testimony concerning Energy Supply O&M expenses and liquidated damages;
- *Paul J. McGregor* responds to witness testimony on the Company's wildfire mitigation activities;
- *Nicole L. Doyle* addresses allocation issues, including the allocation of wildfire mitigation costs;
- *William T. Kowalowski* responds to testimony on property taxes and provides more current property tax information, as discussed in his Direct Testimony;
- *Robert L. Miller* addresses insurance premium expense issues and provides the Company's updated excess liability insurance costs;
- *Richard R. Schrubbe* responds to Intervenor testimony on the Company's prepaid pension asset;
- *Jeffrey L. West* addresses testimony regarding the Company's tracker proposals for costs incurred for compliance with the Good Neighbor

Plan and for costs associated with complying with EPA Coal Combustion Residuals (CCR) rules for investigation, monitoring and possible remediation of Company CCR sites;

- *Yen Ly* responds to Intervenor testimony on employee compensation and benefits issues;
- *Robert V. Mustich* addresses testimony regarding executive compensation;
- *Mark P. Moeller* addresses testimony regarding depreciation and remaining lives;
- *Nicholas F. Martin* responds to Intervenor witnesses' testimony regarding equity, energy justice, and environmental justice issues;
- *Christopher J. Barthol* replies to testimony on class cost of service issues; and
- *Nicholas N. Paluck* addresses the rate design issues raised in Intervenor testimony.

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. The Company's rebuttal case comprehensively responds to the intervenor testimony in this matter and reflects certain changed circumstances and new information, not available when we filed this case. In developing our rebuttal filing, we incorporated a number of revenue requirement changes related to this new information that have significantly lowered our request and that, if adopted, will result in just and reasonable rates for our customers and for the Company.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

Northern States Power Company
Annual Sales - MWh

Docket No. E002/GR-24-320
Exhibit___(AAL-2), Schedule 1A
Page 1 of 1

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	CAGR 2014-2024
NSP-MN												
Residential	8,784,578	8,505,355	8,621,046	8,413,243	8,905,592	8,552,005	9,033,597	9,276,160	9,095,482	9,056,420	8,676,639	-0.12%
Commercial	13,764,808	13,573,612	13,491,958	13,219,280	13,390,274	12,967,627	12,082,902	12,357,741	12,638,135	12,542,470	12,191,505	-1.21%
Industrial	8,179,537	8,209,595	8,159,584	8,090,294	8,127,676	7,621,916	7,004,313	7,157,573	7,241,299	7,084,321	6,838,715	-1.77%
Transportation	23,713	24,209	24,102	23,966	25,832	25,109	20,410	22,728	19,941	18,029	15,332	-4.27%
Retail	30,752,635	30,312,772	30,296,689	29,746,784	30,449,373	29,166,657	28,141,222	28,814,203	28,994,858	28,701,240	27,722,191	-1.03%
National												
Residential	768,975,399	778,512,963	782,687,544	760,282,531	803,771,578	779,954,694	796,861,217	798,770,644	817,912,572	775,693,182	787,557,391	0.24%
Commercial	680,509,736	685,973,506	683,615,259	673,732,202	679,542,564	664,215,317	621,821,853	638,349,214	665,849,942	663,056,911	676,267,864	-0.06%
Industrial	458,399,942	456,933,968	445,343,456	442,388,808	445,235,332	437,292,073	416,375,511	430,564,245	447,392,511	432,083,294	434,335,764	-0.54%
Transportation	1,010,121	943,630	876,409	839,585	888,773	1,027,467	904,272	886,078	877,471	1,046,324	926,130	-0.86%
Retail	1,908,895,197	1,922,364,068	1,912,522,668	1,877,243,125	1,929,438,247	1,882,489,551	1,835,962,853	1,868,570,181	1,932,032,496	1,871,879,711	1,899,087,148	-0.05%
MN - Non-NSP-MN Utilities												
Residential	1,708,902	1,574,820	1,543,988	1,543,099	1,618,888	1,597,739	1,593,262	1,586,055	1,614,366	1,542,288	1,490,838	-1.36%
Commercial	2,439,136	2,398,314	2,382,179	2,367,806	2,403,221	2,336,888	2,222,453	2,270,973	2,281,880	2,272,482	2,219,342	-0.94%
Industrial	7,577,013	6,840,136	6,819,348	7,685,526	7,697,806	7,740,786	6,634,780	7,646,763	7,197,321	7,452,006	7,413,014	-0.22%
Transportation	-	-	-	-	-	-	-	-	-	-	-	0.00%
Retail	11,725,050	10,813,270	10,745,516	11,596,430	11,719,915	11,675,413	10,450,494	11,503,791	11,093,567	11,266,776	11,123,194	-0.53%
Upper Midwest*												
Residential	61,373,933	60,184,211	61,931,659	59,733,634	63,388,226	61,079,078	64,483,747	64,631,004	63,775,736	60,755,793	61,053,691	-0.05%
Commercial	72,256,244	73,128,600	73,815,779	73,123,861	74,220,012	72,288,440	67,971,871	70,306,146	71,518,452	71,950,246	72,232,915	0.00%
Industrial	58,208,687	57,961,539	58,639,694	59,154,116	59,670,443	57,611,953	51,555,581	54,457,730	55,264,212	55,006,996	54,630,890	-0.63%
Transportation	25,032	28,692	28,515	29,986	32,823	32,696	25,489	26,999	25,361	24,620	22,117	-1.23%
Retail	191,863,896	191,303,042	194,415,646	192,041,597	197,311,505	191,012,167	184,036,689	189,421,879	190,583,761	187,737,655	187,939,614	-0.21%

Data Source: Form EIA 861M (formerly EIA-826), IOUs reporting data for the time period 2014 - 2024.
* Includes states that make up Xcel Energy Upper Midwest System: MN, ND, SD, WI, and MI.

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	CAGR 2014-2024
NSP-MN												
Residential	13,363,042	13,466,067	13,573,284	13,686,433	13,799,495	13,914,949	14,059,093	14,234,337	14,389,468	14,553,476	14,760,678	1.00%
Commercial	1,633,306	1,643,244	1,653,562	1,661,594	1,674,464	1,689,004	1,696,317	1,712,313	1,716,255	1,726,781	1,736,621	0.62%
Industrial	5,254	5,992	6,037	6,050	6,066	6,067	6,019	5,964	5,875	5,771	5,761	0.93%
Transportation	12	12	12	12	12	12	12	12	12	12	12	0.00%
Retail	15,001,614	15,115,315	15,232,895	15,354,089	15,480,037	15,610,032	15,761,441	15,952,626	16,111,610	16,286,040	16,503,072	0.96%
National												
Residential	907,034,197	929,843,203	940,168,477	943,995,941	948,961,773	938,337,606	946,718,427	955,173,570	967,794,255	970,177,285	968,206,092	0.65%
Commercial	122,608,786	124,297,950	124,799,616	125,018,496	124,638,753	124,407,735	124,938,439	126,008,714	127,414,980	127,521,819	126,627,931	0.32%
Industrial	4,864,405	4,810,224	4,801,343	4,770,324	4,697,394	4,666,932	4,644,053	4,645,770	4,644,696	4,613,400	4,451,825	-0.88%
Transportation	323	329	372	386	350	386	402	378	382	392	396	2.06%
Retail	1,034,507,711	1,058,951,706	1,069,769,808	1,073,785,147	1,078,298,270	1,067,412,659	1,076,301,321	1,085,828,432	1,099,854,313	1,102,312,896	1,099,286,244	0.61%
MN - Non-NSP-MN Utilities												
Residential	2,012,363	2,035,214	2,041,412	2,050,017	2,056,437	2,085,028	2,077,106	2,094,124	2,102,021	2,107,906	2,113,218	0.49%
Commercial	411,986	418,293	422,384	426,786	429,162	439,506	442,785	446,289	449,700	460,357	463,861	1.19%
Industrial	4,808	4,857	4,887	4,809	4,692	4,678	4,672	4,642	4,649	4,965	5,160	0.71%
Transportation	-	-	-	-	-	-	-	-	-	-	-	0.00%
Retail	2,429,157	2,458,364	2,468,683	2,481,612	2,490,291	2,529,212	2,524,563	2,545,055	2,556,370	2,573,228	2,582,239	0.61%
Upper Midwest*												
Residential	90,522,359	91,103,209	91,714,134	92,383,655	92,967,582	93,508,701	94,301,051	94,959,760	95,607,661	96,267,463	97,031,191	0.70%
Commercial	11,805,910	11,970,142	12,065,236	12,147,603	12,198,229	12,304,319	12,344,495	12,436,503	12,512,001	12,620,889	12,731,326	0.76%
Industrial	162,358	79,720	79,958	80,696	79,424	78,927	77,638	77,083	74,806	74,167	74,383	-7.51%
Transportation	16	36	36	45	48	60	60	60	60	60	60	14.13%
Retail	102,490,643	103,153,107	103,859,364	104,611,999	105,245,283	105,892,007	106,723,244	107,473,406	108,194,528	108,962,579	109,836,960	0.69%

Data Source: Form EIA 861M (formerly EIA-826), IOUs reporting data for the time period 2014 - 2024.
* Includes states that make up Xcel Energy Upper Midwest System: MN, ND, SD, WI, and MI.

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	CAGR 2014-2024
NSP-MN												
Residential	657	632	635	615	645	615	643	652	632	622	588	-1.11%
Commercial	8,428	8,260	8,159	7,956	7,997	7,678	7,123	7,217	7,364	7,263	7,020	-1.81%
Industrial	1,556,821	1,370,093	1,351,596	1,337,239	1,339,874	1,256,291	1,163,700	1,200,130	1,232,562	1,227,572	1,187,071	-2.68%
Transportation	1,976,045	2,017,434	2,008,479	1,997,186	2,152,643	2,092,379	1,700,805	1,894,041	1,661,737	1,502,403	1,277,694	-4.27%
Retail	2,050	2,005	1,989	1,937	1,967	1,868	1,785	1,806	1,800	1,762	1,680	-1.97%
National												
Residential	848	837	832	805	847	831	842	836	845	800	813	-0.41%
Commercial	5,550	5,519	5,478	5,389	5,452	5,339	4,977	5,066	5,226	5,200	5,341	-0.38%
Industrial	94,236	94,992	92,754	92,738	94,783	93,700	89,658	92,679	96,323	93,658	97,564	0.35%
Transportation	3,127,310	2,868,175	2,355,939	2,175,091	2,539,350	2,661,831	2,249,434	2,344,121	2,297,045	2,669,195	2,338,711	-2.86%
Retail	1,845	1,815	1,788	1,748	1,789	1,764	1,706	1,721	1,757	1,698	1,728	-0.66%
MN - Non-NSP-MN Utilities												
Residential	849	774	756	753	787	766	767	757	768	732	705	-1.84%
Commercial	5,920	5,734	5,640	5,548	5,600	5,317	5,019	5,089	5,074	4,936	4,784	-2.11%
Industrial	1,575,918	1,408,305	1,395,406	1,598,155	1,640,624	1,654,721	1,420,116	1,647,299	1,548,144	1,500,908	1,436,631	-0.92%
Transportation	-	-	-	-	-	-	-	-	-	-	-	0.00%
Retail	4,827	4,399	4,353	4,673	4,706	4,616	4,140	4,520	4,340	4,378	4,308	-1.13%
Upper Midwest*												
Residential	678	661	675	647	682	653	684	681	667	631	629	-0.74%
Commercial	6,120	6,109	6,118	6,020	6,084	5,875	5,506	5,653	5,716	5,701	5,674	-0.76%
Industrial	358,521	727,064	733,381	733,049	751,290	729,940	664,051	706,482	738,767	741,664	734,454	7.43%
Transportation	1,564,519	796,999	792,081	666,358	683,815	544,931	424,819	449,979	422,687	410,331	368,625	-13.46%
Retail	1,872	1,855	1,872	1,836	1,875	1,804	1,724	1,763	1,761	1,723	1,711	-0.89%

Data Source: Form EIA 861M (formerly EIA-826), IOUs reporting data for the time period 2014 - 2024.
* Includes states that make up Xcel Energy Upper Midwest System: MN, ND, SD, WI, and MI.

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	CAGR 2014-2024
NSP-MN												
Residential	1,119,975	1,071,680	1,136,511	1,159,883	1,259,859	1,165,203	1,241,195	1,291,300	1,419,019	1,476,865	1,473,375	2.78%
Commercial	1,335,774	1,284,469	1,338,790	1,428,281	1,412,579	1,348,643	1,268,029	1,430,472	1,675,273	1,671,918	1,566,594	1.61%
Industrial	622,928	612,585	631,865	634,198	661,416	611,528	558,603	643,910	743,149	734,180	666,241	0.67%
Transportation	2,321	2,300	2,433	2,291	2,475	2,383	1,919	2,360	2,450	2,227	1,949	-1.74%
Retail	3,080,999	2,971,034	3,109,599	3,224,654	3,336,329	3,127,757	3,069,746	3,368,042	3,839,892	3,885,190	3,708,160	1.87%
National												
Residential	98,442,059	100,860,157	100,631,924	100,747,864	105,549,352	102,274,257	105,647,509	111,195,795	126,710,890	128,170,031	132,983,825	3.05%
Commercial	73,869,444	73,259,148	70,739,496	71,895,825	71,882,047	69,855,326	65,133,599	70,436,168	82,580,813	84,221,053	86,364,318	1.58%
Industrial	33,242,841	31,971,805	30,555,686	31,281,846	31,358,354	30,512,970	28,737,425	31,729,714	38,365,914	35,788,549	35,813,070	0.75%
Transportation	93,913	79,416	75,242	76,745	80,074	98,404	85,949	87,710	110,628	142,643	98,133	0.44%
Retail	205,648,257	206,170,527	202,002,348	204,002,280	208,869,826	202,740,956	199,604,481	213,449,388	247,768,246	248,322,275	255,259,345	2.18%
MN - Non-NSP-MN Utilities												
Residential	157,141	142,990	142,674	158,515	173,101	175,061	173,182	197,067	210,934	200,511	211,578	3.02%
Commercial	197,611	190,017	192,990	212,619	224,003	223,691	211,424	247,804	271,409	267,415	268,966	3.13%
Industrial	412,636	377,142	365,985	477,429	481,364	495,670	450,322	574,343	610,288	604,889	620,731	4.17%
Transportation	-	-	-	-	-	-	-	-	-	-	-	0.00%
Retail	767,389	710,149	701,649	848,563	878,469	894,422	834,928	1,019,214	1,092,632	1,072,815	1,101,275	3.68%
Upper Midwest*												
Residential	8,371,468	8,293,824	8,882,307	8,720,145	9,258,581	8,980,679	9,730,485	10,306,219	10,627,759	10,697,003	11,054,733	2.82%
Commercial	7,606,287	7,603,828	7,759,301	7,961,777	8,074,814	7,937,137	7,570,036	8,262,153	8,850,435	9,244,741	9,439,074	2.18%
Industrial	4,321,627	4,145,432	4,148,069	4,314,610	4,318,514	4,170,807	3,791,275	4,301,891	4,781,257	4,776,540	4,687,144	0.82%
Transportation	2,476	2,819	2,952	3,018	3,233	3,225	2,529	2,915	3,166	3,168	2,960	1.80%
Retail	20,301,858	20,045,904	20,792,628	20,999,550	21,655,142	21,091,848	21,094,325	22,873,177	24,262,617	24,721,452	25,183,912	2.18%

Data Source: Form EIA 861M (formerly EIA-826), IOUs reporting data for the time period 2014 - 2024.
* Includes states that make up Xcel Energy Upper Midwest System: MN, ND, SD, WI, and MI.

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	CAGR 2014-2024
NSP-MN												
Residential	84	80	84	85	91	84	88	91	99	101	100	1.76%
Commercial	818	782	810	860	844	798	748	835	976	968	902	0.99%
Industrial	118,563	102,234	104,665	104,826	109,037	100,796	92,807	107,966	126,494	127,219	115,647	-0.25%
Transportation	193,456	191,641	202,752	190,942	206,234	198,597	159,946	196,679	204,182	185,586	162,375	-1.74%
Retail	205	197	204	210	216	200	195	211	238	239	225	0.90%
National												
Residential	109	108	107	107	111	109	112	116	131	132	137	2.38%
Commercial	602	589	567	575	577	562	521	559	648	660	682	1.25%
Industrial	6,834	6,647	6,364	6,558	6,676	6,538	6,188	6,830	8,260	7,758	8,045	1.64%
Transportation	290,751	241,387	202,264	198,821	228,782	254,933	213,804	232,036	289,603	363,884	247,811	-1.59%
Retail	199	195	189	190	194	190	185	197	225	225	232	1.57%
MN - Non-NSP-MN Utilities												
Residential	78	70	70	77	84	84	83	94	100	95	100	2.52%
Commercial	480	454	457	498	522	509	477	555	604	581	580	1.91%
Industrial	85,823	77,649	74,890	99,278	102,593	105,958	96,387	123,727	131,273	121,831	120,297	3.43%
Transportation	-	-	-	-	-	-	-	-	-	-	-	0.00%
Retail	316	289	284	342	353	354	331	400	427	417	426	3.05%
Upper Midwest*												
Residential	92	91	97	94	100	96	103	109	111	111	114	2.11%
Commercial	644	635	643	655	662	645	613	664	707	732	741	1.41%
Industrial	26,618	52,000	51,878	53,467	54,373	52,844	48,833	55,809	63,915	64,402	63,014	9.00%
Transportation	154,744	78,301	82,007	67,059	67,361	53,745	42,152	48,580	52,768	52,806	49,338	-10.80%
Retail	198	194	200	201	206	199	198	213	224	227	229	1.47%

Data Source: Form EIA 861M (formerly EIA-826), IOUs reporting data for the time period 2014 - 2024.
* Includes states that make up Xcel Energy Upper Midwest System: MN, ND, SD, WI, and MI.

Direct Testimony and Schedules
Benjamin C. Halama

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-24-320
Exhibit___(BCH-1)

2025 Test Year and 2026 Plan Year
Overall Revenue Requirements
Rate Base
Income Statement
Rate Rider Recovery 2025-2026

November 1, 2024

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Benjamin C. Halama. I am the Director of Revenue Analysis for Xcel Energy Services Inc. (XES or the Service Company), the service company for Xcel Energy Inc. and its operating company subsidiaries.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have more than nine years of experience at XES, supporting Northern States Power Company–Minnesota (NSPM or the Company) in the areas of regulatory accounting, financial operations, and revenue requirements. In my current role, I am responsible for the development of jurisdictional revenue requirements for all NSPM jurisdictions. My resume is attached as Exhibit___(BCH-1), Schedule 1, Resume.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. In my Direct Testimony, I support the Company's Minnesota jurisdiction electric operations cost of service, revenue requirements, and revenue deficiency for each of the two years of the Company's multi-year rate plan (MYRP), which are calendar years 2025 (the test year) and 2026 (the plan year). Overall, the net deficiencies and retail revenue requirements for the test year and plan year are summarized in Table 1 below, including the 2025 request and the incremental 2026 request that together form the Company's overall requests in this proceeding:

Table 1
2025-2026 Incremental Revenue Requests
Minnesota Jurisdictional Deficiency Net of Interchange ($s in millions)

MYRP Year	2025	2026
Incremental Annual Deficiency ($)	$353.3	$137.5
Incremental Annual Deficiency (%)*	9.6%	3.6%

*This is calculated using the annual revenue request over the forecasted present revenues in each applicable year, less prior year(s).

I provide the financial data supporting these overall revenue deficiencies for the State of Minnesota retail electric jurisdiction, including a description of cost changes, the data we provide, and our selection of the test year and plan year. Further, I present:

- our jurisdictional cost of service study (COSS) and the revenue requirement effects of our utility and jurisdictional allocations; and
- our revenue requirement, including rate base and income statement components, with related adjustments and amortizations.

My testimony also supports the 2025 and 2026 requested interim rate increases discussed in the Company's Petition for Interim Rates. Company witness Amy A. Liberkowski provides additional support for the interim rate increases proposed as a part of our MYRP, as does the Notice and Petition for Interim Rates, included in Volume 1 of our Application.

In addition, I explain our treatment of riders, and identify certain compliance requirements addressed in our general rate filing.

I relied on information provided by other Company witnesses in this proceeding to develop many of the 2025-2026 MYRP revenue requirement adjustments discussed in my Direct Testimony.

Q. HOW IS THE REST OF YOUR DIRECT TESTIMONY ORGANIZED?

A. I present my testimony in the following sections:

- Section II, *Case Overview*, summarizes our jurisdictional revenue requirement for the 2025 test year and 2026 plan year, and discusses the key drivers of cost increases compared to our last MYRP established in Docket No. E002/GR-21-630 (the 2022-2024 MYRP).
- Section III, *Supporting Information*, provides information related to the data provided in our application, the selection of the test year and plan year, and the jurisdictional COSS.
- Section IV, *Rate Base*, identifies and explains the components of rate base, and supports the reasonableness of the Company's projected 2025 test year and 2026 plan year rate base.
- Section V, *Income Statement*, identifies and explains the major components of the income statement and supports the reasonableness of the Company's proposed 2025 test year and 2026 plan year income statement.
- Section VI, *Utility and Jurisdictional Allocations*, explains why it is necessary for the Company to allocate costs among its affiliates and between jurisdictions, and describes the utility and jurisdictional allocators that are used in determining the MYRP revenue requirements.
- Section VII, *Annual Adjustments to the MYRP*, presents adjustments affecting the 2025 test year and 2026 plan year revenue requirements, providing both rate base and income statement impacts.

- Section VIII, *Costs Recovered in Riders and Trackers*, presents our proposed treatment of costs recovered in riders or trackers during the MYRP period, providing details about which riders and trackers we propose to use and costs we propose to move into base rates, coincident with the implementation of final rates.
- Section IX, *Compliance with Prior Commission Orders*, provides information related to specific requirements from prior Minnesota Public Utilities Commission (Commission) Orders that have not been addressed elsewhere in my testimony.
- Section X, *Conclusion*, summarizes our request.

Q. ARE ALL THE DOLLAR VALUES PRESENTED IN YOUR TESTIMONY JURISDICTIONALIZED TO STATE OF MINNESOTA ELECTRIC JURISDICTION?

A. While most of the dollar values presented in my testimony are jurisdictionalized to State of Minnesota Electric Jurisdiction, there are several instances where dollars are either Total Company, or net of Interchange Agreement (IA) billings to Northern States Power Company-Wisconsin (NSPW). Dollar values that are Total Company or net of Interchange Agreement billings to NSPW are labeled accordingly.

Q. DO YOU PROVIDE INFORMATION IN COMPLIANCE WITH PAST COMMISSION ORDERS AND COMPANY COMMITMENTS?

A. Yes. Throughout my testimony, I note where I am providing information related to prior Commission Orders and Company commitments. In Section IX, I provide additional information related to compliance with prior Commission Orders that have not been addressed elsewhere in my testimony.

II. CASE OVERVIEW

Q. WHAT TOPICS DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section, I will:

- present the jurisdictional revenue requirements and revenue deficiencies for Minnesota for the 2025 test year and 2026 plan year, referred to in total as the "MYRP Forecast";
- present a summary comparison of the costs in the MYRP Forecast to the costs in the 2022-2024 MYRP approved in our last completed rate case, which include costs, changes, and true-ups in each year of the MYRP; and
- provide an explanation of the primary sources of the changes in overall costs, including plant-related costs and operations and maintenance (O&M) costs.

A. MYRP Jurisdictional Revenue Requirements and Deficiencies

Q. PLEASE DESCRIBE THE BASIS OF THE COMPANY'S MYRP PROPOSAL.

A. The Company's two-year plan utilizes 2025 as the test year, with 2026 as an additional plan year developed using budgeted capital additions and budgeted O&M expenses. Also included in the proposal are impacts to other rate base items, sales adjustments, and other adjustments impacting the revenue requirements for these years, so that each year represents a cost of service approach to rate-setting for both capital and O&M.

Q. WHAT IS THE 2025 TEST YEAR JURISDICTIONAL OVERALL REVENUE REQUIREMENT AND REVENUE DEFICIENCY?

A. The overall jurisdictional revenue requirement for the 2025 test year is $4.02 billion. The 2025 test year revenue deficiency, excluding rider roll-ins, is $353.3 million. This 2025 test year revenue deficiency amount represents a 9.6 percent increase in retail revenues from base rates compared to projected 2025 retail revenues at present rates. A summary of the 2025 revenue deficiency (in dollars and as a percent) is provided in Exhibit___(BCH-1), Schedule 2, Summary of Revenue Requirements. The calculation of these dollar amounts is provided in Exhibit___(BCH-1), Schedule 3, Cost of Service Study Summary.

Q. WHAT ARE THE OVERALL REVENUE REQUIREMENT AND REVENUE DEFICIENCIES FOR THE 2026 PLAN YEAR?

A. The overall jurisdictional revenue requirements for the 2026 plan year is $4.22 billion. The 2026 incremental revenue deficiency as compared to the 2025 requested revenues, excluding rider roll-ins, is $137.5 million or 3.6 percent. Combined, the overall revenue requirement deficiency for the 2026 plan year is $490.7 million, which represents a 13.2 percent increase in retail revenues from base rates in 2026 compared to projected 2026 retail revenues at present rates. A summary of the 2026 revenue deficiency (in dollars and as percentages) is provided in Schedule 2, Summary of Revenue Requirements. The calculation of these dollar amounts is provided in Schedule 3, COSS Summary.

Q. WHAT IS THE AMOUNT OF THE INTERIM RATE REVENUE DEFICIENCY IN 2025?

A. The Notice and Petition for Interim Rates (Interim Rate Petition) supports an interim revenue deficiency based on the 2025 test year of $223.8 million, which results in an interim rate increase of 6.1 percent beginning January 1, 2025.

Q. IS AN INTERIM RATE REQUEST FOR 2026 INCLUDED IN THIS FILING?

A. Yes. As discussed in the Direct Testimony of Company witness Liberkowski and in the Interim Rate Petition, the Company is also proposing an interim rate adjustment for 2026 as part of its multi-year rate plan filing. The 2026 interim rate revenue deficiency includes an additional $138.8 million beginning on January 1, 2026, which equates to an additional interim rate increase of 3.7 percent in 2026.

Q. HOW DOES THE COMPANY CALCULATE ITS REVENUE REQUIREMENT AND REVENUE DEFICIENCY?

A. The general formula for calculation of the revenue requirement and revenue deficiency is depicted below in Table 2:

Table 2
Revenue Requirement and Revenue Deficiency

	Item	2025 Test Year Amount ($000s)	2026 Plan Year Amount ($000s)	Exhibit__ (BCH-1), Sch. 3 Reference
	Average Rate Base	$13,237,993	$14,033,262	Page 1, Line 44
multiplied by	Cost of capital	7.56%	7.55%	Page 1, Line 20
	Operating Income Requirement	**$1,000,792**	**$1,059,511**	Page 4, Line 158
	Current Retail Revenue	$3,666,148	$3,725,121	Page 2, Line 47 + Line 48
plus	Current Other Revenue	$862,988	$856,179	Page 2, Line 49
equals	Current Total Revenue	$4,529,136	$4,581,300	Page 2, Line 50
minus	Operating Expenses	$2,880,314	$2,935,840	Page 2, Line 74
minus	Depreciation Expense	$914,479	$930,236	Page 2, Line 76
minus	Amortization Expense	$44,939	$54,152	Page 2, Line 77
minus	Taxes	$21,893	$36,690	Page 3, Line 135
plus	AFUDC	$81,561	$85,437	Page 4, Line 140 + Line 141
equals	**Total Available for Return**	**$749,071**	**$709,819**	Page 4, Line 143
	Operating Income Requirement	$1,000,792	$1,059,511	Page 4, Line 158
minus	Total Available for Return	$749,071	$709,819	Page 4, Line 143
equals	**Income Deficiency**	**$251,721**	**$349,692**	Page 4, Line 160
multiplied by	Gross Revenue Conversion Factor	1.403351	1.403351	Page 4, Line 162
equals	**Revenue Deficiency**	**$353,253**	**$490,740**	Page 4, Line 163
plus	Current Retail Revenue	$3,666,148	$3,725,121	Page 4, Line 166
equals	**Total Revenue Requirement**	**$4,019,401**	**$4,215,862**	Page 4, Line 168

Q. HAS THE COMPANY PROVIDED AN EXPLANATION OF THE ASSUMPTIONS AND APPROACHES USED IN DEVELOPING THE MYRP FORECAST OPERATING INCOME?

A. Yes. An explanation is provided in the Financial Information section of Volume 3 (Required Information) of this Application. In addition, workpapers supporting the 2025-2026 MYRP cost of service are provided in Volume 4 (MYRP Workpapers) of this Application.

Q. HOW DOES THE COMPANY TREAT CAPITAL AND O&M COSTS IN THE 2025-2026 MYRP?

A. Our proposal uses the following reasoning to develop costs:

1. Capital, capital-related, and O&M costs follow the Company's budget, except as needed to comply with prior Commission Orders or adjustments the Company is specifically proposing in this proceeding. (Capital-related consists of depreciation and allowance for funds used during construction (AFUDC) as well as the cost of capital).
2. Fuel revenues and expenses for both years of the 2025-2026 MYRP are represented in this docket based on the level filed in the Company's July 31, 2024 fuel update[1] consistent with the Company's August 12, 2019 Compliance Filing approved by the Commission in Docket No. E999/CI-03-802.[2]
3. Expenses that have jurisdiction-specific regulatory accounting treatment follow that treatment. For example:

[1] Company's July 31, 2024, Reply Comments, Docket No. E002/AA-24-63.
[2] Fuel expenses for the 2025-2026 MYRP are held flat at the filed level, but the Fuel and Purchased Energy line of the cost of service model Schedule 3, row 58) fluctuates due to inclusion of fuel handling base O&M, interchange billings and the Benson PPA).

a. The Company amortizes nuclear fueling outage costs over the periods between outages. These costs should follow the Company's budget; and

b. Expenses related to the Company's pension and benefit costs have several regulatory adjustments based on the outcome of the Company's recent rate cases.

4. Secondary calculations necessary for a full COSS are based on the results of the above items. For example:

a. Cash Working Capital balance related to the revenues and expenses developed above;

b. Deferred Tax Asset balance and deferred tax expense related to a Net Operating Loss calculation; and

c. Change in debt interest expense related to the budgeted change in debt costs and the budget of rate base.

B. Case Drivers

Q. HAVE YOU PREPARED A COMPARISON OF THE COSTS IN THE MYRP FORECAST TO CURRENT RATES RESULTING FROM THE 2022-2024 MYRP?

A. Yes. I provide an explanation of the detailed case drivers of the deficiency using a comparison of the 2025 test year (including rider roll-ins) with the base rates in effect in 2024 as a result of the MYRP in Docket No. E002/GR-21-630 (the 2022-2024 MYRP). My analysis also includes a comparison of year two (2026) of the MYRP. My analysis differs from the Direct Testimony analyses of the Company's business area witnesses, who discuss costs and cost changes in more detail and in terms of actual costs and budgets (not revenue deficiencies). Therefore, my discussion of key cost drivers reflects dollar values that are, in large part, different from their discussions. In addition, I discuss these drivers at a high level, and defer to the business area witnesses to provide more detail around the activities and changes giving rise to these drivers.

Q. HAVE YOU PREPARED A SCHEDULE IDENTIFYING THE CHANGES IN THE MAJOR COST ELEMENTS SINCE THE COMPANY'S LAST ELECTRIC RATE CASE?

A. Yes. I provide Exhibit___(BCH-1), Schedule 6, Detailed Case Drivers, which provides a Summary of Major Cost Drivers (identification of case drivers for the MYRP Forecast), including details of the categories identified in Table 3 below.

Table 3
MYRP Net Incremental Deficiency ($ in millions)

		Increase (Decrease) 2025 TY to 2024 MYRP		Increase (Decrease) 2026 TY to 2025 TY		2-Year MYRP
Capital and Capital Related		$273.9		$72.4		$346.3
Amortizations		(4.1)		(0.3)		(4.4)
Taxes		(66.0)		52.5		(13.4)
Operating Expense		84.6		66.4		151.0
Other Margin Impacts		64.9		(53.6)		11.3
Total Net Incremental Deficiency		$353.3		$137.5		$490.7

**Differences between components of deficiency and total due to rounding.*

As noted above, in addition to the discussion in this section, support for our proposed increase in rates for the 2025 test year and 2026 plan year is provided in the Direct Testimonies of the Company's business area witnesses and the Direct Testimony of Company witness Gregory J. Robinson.

Q. PLEASE DESCRIBE THE REVENUE REQUIREMENT IMPACT FOR THE PRINCIPAL CHANGES IN CAPITAL AND CAPITAL RELATED COSTS.

A. Table 4 below compares the MYRP Forecast revenue requirements with the comparable revenue requirements for the 2024 MYRP, by category, for capital plant related costs as shown on Schedule 6, Detailed Case Drivers.

Table 4
Capital and Capital Related Cost Changes ($ in millions)

	Increase (Decrease) 2025 TY to 2024 MYRP	Increase (Decrease) 2026 TY to 2025 TY	2-Year MYRP
Nuclear	$26.8	$5.9	$32.7
Steam	10.4	(30.2)	(19.9)
Wind	41.7	(6.0)	35.7
All Other Production	(11.3)	13.0	1.7
Transmission	16.6	19.5	36.1
Distribution	65.6	51.9	117.5
General and Intangible	30.7	16.8	47.5
DTA (Federal Credits & NOL)	(21.9)	(3.3)	(25.2)
Other Rate Base	13.0	(1.3)	11.7
Cost of Capital	102.2	6.1	108.3
TOTAL Capital and Capital Related	$273.9	$72.4	$346.3

**Differences between components of deficiency and total due to rounding.*

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN NUCLEAR CAPITAL COSTS.

A. The MYRP Forecast revenue requirements include a $32.7 million increase in Nuclear. This increase is primarily due to capital investments for nuclear fuel, dry cask storage, mandated compliance, and reliability. Additional information regarding nuclear projects is discussed in the Direct Testimony of Company witness Christopher R. Church.

Q. WHAT ARE THE PRINCIPAL CHANGES IN WIND CAPITAL COSTS?

A. The MYRP Forecast revenue requirements include a $35.7 million increase to Wind. This increase is due primarily to capital investments for the Nobles and Grand Meadow Wind Repower projects, which were placed in service in 2022 and 2023, respectively. Additional information regarding wind projects is provided in the Direct Testimony of Company witness Randy A. Capra.

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN TRANSMISSION CAPITAL COSTS.

A. The MYRP Forecast revenue requirements include a $36.1 million increase to Transmission. This increase is due mainly to increases in asset renewals, reliability requirements, communication infrastructure, as well as regional expansion interconnection projects. Additional information regarding transmission projects is provided in the Direct Testimony of Company witness David J. Berklund.

Q. PLEASE IDENTIFY THE PRINCIPAL CHANGES IN DISTRIBUTION CAPITAL COSTS.

A. The MYRP Forecast revenue requirements include a $117.5 million increase to Distribution. This increase is due to capital investments relating to increased investment in Distribution's asset health and reliability programs to address the portions of our system that are closest to our customers, such as pole, cable, and substation transformer replacements. This increase is also due to investments to address capacity constraints on our system, as well as to support distributed energy resources, and provides support for new business and localized load growth, mandated relocation projects, and our electric vehicle programs. Additionally, Distribution will be making investments targeted to mitigate the risk of wildfires, including investments in operational mitigations, overhead assessment of assets and resulting mitigations, and small conductor and pole replacements to mitigate wildfire ignition risk. Distribution also manages work associated with the Advanced Grid Intelligence & Security (AGIS) initiative, including advanced metering technology (AMI), the field area network (FAN), and Fault Location, Isolation, and Service Restoration (FLISR), but most AMI and FAN costs are certified for inclusion in the Transmission Cost Recovery (TCR) Rider and are not reflected in base rates in this matter. Additional information regarding distribution projects is discussed in the Direct Testimony of Company witness Marty D. Mensen.

Q. WHAT ARE THE PRINCIPAL CHANGES IN GENERAL AND INTANGIBLE CAPITAL COSTS?

A. The MYRP Forecast revenue requirements include a $47.5 million increase to General and Intangible. This increase is primarily due to increasing technology needs and capital investments relating to replacing aging technology, enhancing capabilities, wildfire mitigation, and cyber security initiatives. It also includes AGIS costs that are not included in the TCR Rider. Additional information regarding general and intangible projects is discussed in the Direct Testimony of Company witness Megan N. Scheller.

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN DEFERRED TAX ASSET (DTA) CAPITAL COSTS.

A. The MYRP Forecast revenue requirements include a $25.2 million decrease to the DTA. This decrease is due mainly to market sales of federal production tax credits (PTC). Additional information regarding PTC market sales is discussed in Section VII of my testimony.

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN COST OF CAPITAL.

A. The MYRP Forecast revenue requirements include a $108.3 million increase related to changes in cost of capital. The change in cost of capital is due to a requested 10.3 percent return on equity (ROE) and minimal increases in the cost of short-term and long-term debt. Capital structure and cost of debt are discussed in the Direct Testimony of Company witness Todd A. Wehner. Company witness Joshua C. Nowak of Concentric Energy Advisors, Inc. discusses the Company's recommended ROE.

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN TAXES.

A. The MYRP Forecast revenue requirements include a $13.4 million decrease to taxes. This decrease is due to increased Production Tax Credits (PTCs) associated with new and existing wind farms being moved to base rate recovery in this case partially offset by an increase in income taxes.

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN O&M COSTS.

A. Table 5 below compares the MYRP Forecast revenue requirements with the comparable revenue requirements for the 2024 MYRP plan year, by category, for operating expenses as shown on Schedule 6, Detailed Case Drivers.[3]

[3] As noted in Section VII.F of my Direct Testimony (Rebuttal Adjustments), after the cost of service was completed, we discovered that the TCR rider O&M removal adjustment was inadvertently removed from the wrong FERC account. While this has no impact on the MYRP Forecast revenue requirement deficiency or interim rates, the correction of these cost assignments as between FERC accounts affects the depiction of O&M cost drivers. As a result, Schedule 6, Detailed Case Drivers and Table 5 below have been adjusted to reflect the correct FERC accounting. The following discussion of O&M drivers is aligned with my Schedule 6 and Table 5.

Table 5
O&M Cost Changes ($ in millions)

	Increase (Decrease) 2025 TY to 2024 MYRP Year	Increase (Decrease) 2026 TY to 2025 TY	2-Year MYRP
Nuclear	$17.8	$(5.6)	$12.2
Steam	(7.8)	17.0	9.1
Wind	18.6	(5.0)	13.5
Production Interchange	(1.4)	30.4	29.0
Purchased Demand	(24.7)	(14.3)	(39.0)
All Other Production	(2.1)	0.2	(1.9)
Transmission	(4.2)	4.4	0.2
Transmission Interchange	13.1	4.7	17.7
Distribution	4.6	18.9	23.5
Regional Markets	(0.2)	0.5	0.3
Customer Accounting / Info / Service	3.2	6.2	9.4
A&G	67.8	9.2	77.0
TOTAL O&M	$84.6	$66.4	$151.0

**Differences between components of deficiency and total due to rounding.*

Q. WHAT ARE THE PRINCIPAL REASONS FOR THE INCREASE IN NUCLEAR OPERATIONS OPERATING EXPENSE?

A. The MYRP Forecast revenue requirements include a $12.2 million increase in nuclear operating expenses. This increase is primarily due to workforce costs, including internal and external labor, and nuclear-related fees. Additional information regarding nuclear operating expenses is discussed by witness Church.

Q. WHAT ARE THE PRINCIPAL REASONS FOR THE INCREASE IN WIND OPERATING EXPENSE?

A. The MYRP Forecast revenue requirements include a $13.5 million increase in wind operating expenses. This increase is due to the additional operating expense, specifically operations and maintenance contracts and land easement payments associated with new wind farms that have been added to our generation portfolio, as discussed by witness Capra.

Q. WHAT ARE THE PRINCIPAL REASONS FOR THE INCREASE IN PRODUCTION INTERCHANGE EXPENSE?

A. The MYRP Forecast revenue requirements include a $29.0 million increase in production interchange expenses. This increase is due to changes in the NSPW Interchange Agreement bill to NSPM, primarily due to increased capital investment associated with the Wheaton Repower project. The Wheaton Repower project is discussed by witness Capra.

Q. WHAT ARE THE PRINCIPAL REASONS FOR THE DECREASE IN PURCHASED DEMAND OPERATING EXPENSE?

A. The MYRP Forecast revenue requirements include a $39.0 million decrease in purchased demand operating expenses. The decrease is due primarily to updates to and extension of a contract with Manitoba Hydro, resulting in a decreased cost of capacity purchases starting in 2025.

Q. WHAT ARE THE PRINCIPAL REASONS FOR THE INCREASE IN TRANSMISSION INTERCHANGE OPERATING EXPENSE?

A. The MYRP Forecast revenue requirements include a $17.7 million increase in transmission interchange operating expenses. This increase is primarily due to asset renewals, reliability requirements and communication infrastructure projects as discussed in the Direct Testimony witness Berklund.

Q. WHAT ARE THE PRINCIPAL REASONS FOR THE INCREASE IN DISTRIBUTION OPERATING EXPENSE?

A. The MYRP Forecast revenue requirements include a $23.5 million increase in distribution operating expenses. This increase is related to costs for vegetation management activities, largely associated with wildfire risk mitigation, as discussed in the Direct Testimony of witness Mensen.

Q. WHAT ARE THE PRINCIPAL REASONS FOR THE INCREASE IN ADMINISTRATIVE AND GENERAL (A&G) EXPENSE?

A. The MYRP Forecast revenue requirements include a $77.0 million increase in A&G expense. This increase is due to increases in Company labor costs (salaries and benefits) and increases in insurance costs. Additional information regarding Company labor costs is discussed by Company witnesses Yen Ly and Richard R. Schrubbe. Additional information regarding insurance costs is provided by Company witness Robert L. Miller.

Q. PLEASE DESCRIBE HOW CHANGES IN SALES RELATE TO THE REVENUE DEFICIENCY FOR 2025 AND 2026.

A. As discussed by Company witness Benjamin S. Levine, Minnesota electric sales steadily declined from 2008 through 2019 before showing a sharper decline in 2020 due to the impacts of the COVID-19 pandemic on commercial and industrial sales. Sales rebounded over the course of 2021-2023, but overall consumption as of year-end 2023 is still lower than pre-pandemic (2019) levels, and the long-term declining trend for "baseline" sales (excluding growth from EVs and large data centers) is expected to continue due to demand-side management achievements and solar distributed generation. After layering in the current projections for increased EV adoption and new large data centers taking construction load or beginning to ramp up by 2026, the Company's retail revenues show a slight increase in the 2025 test year as compared to the 2024 plan year from the Company's last rate case and are expected to increase again in 2026, decreasing the 2025 and 2026 revenue deficiency.

Q. ARE THERE ANY OTHER MARGIN ITEMS WITH A SIGNIFICANT IMPACT ON THE 2025 REVENUE DEFICIENCY?

A. Yes. The MYRP Forecast revenue requirements include a $108.5 million decrease in other revenue since the 2024 plan year from our prior MYRP. The decrease in other revenue is primarily due to the decrease in capacity revenue from the MISO Planning Resource Auction (PRA) revenues. As discussed in the 2022-2024 MYRP,[4] the capacity revenues received in the 2022 to 2023 MISO planning year and used as a basis for the cost of service development in that rate case were extraordinarily different than historical capacity revenues. The amount included in the MYRP Forecast reflects a return to an amount more in line with historical capacity revenues.

Q. ARE THE FUNCTIONAL CLASS CATEGORIES OF OPERATING EXPENSE COMPARABLE BETWEEN THE 2025 TEST YEAR AND THE DOCKET NO. E002/GR-21-630 2024 PLAN YEAR?

A. Yes. Budget amounts for both periods conform to the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts. To better show cost drivers, especially as they relate to operating margins, some reclassifications are made in the cost driver analysis from the Jurisdictional COSS.

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[4] Rebuttal Testimony of Benjamin Halama at Section II.G, eDockets 202211-190502-03, and Surrebuttal Testimony of Department of Commerce witness Nancy Campbell at Section IV.A, eDockets 202212-191140-02 (Docket No. E002/GR-21-630).

Q. DOES THE IMPLEMENTATION OF FERC ORDER 898 AFFECT THE COMPARISON OF ACCOUNTS IN YOUR DIRECT TESTIMONY?

A. No. As discussed in more detail by Company witness Allison M. Johnson, FERC Order 898 creates new accounts for wind, solar, and other renewable generating assets; creates a new functional class for energy storage accounts; codifies the accounting treatment for environmental credits; and creates new accounts within existing functions for computer hardware, software, and communication equipment; but the new accounting will not be effective until January 1, 2025. We are still working through these changes. As such, there is no effect on the initial filing of this case.

Q. DID YOU INCLUDE COMPARISONS OF THE CHANGE IN THE FUEL AND PURCHASED ENERGY EXPENSE AS PART OF THE O&M EXPENSE ANALYSIS?

A. No. Although the cost of fuel and purchased energy are considered to be an operating expense, recovery occurs through the Company's separate fuel clause adjustment (FCA) mechanism and true-up process. I provide a reconciliation of fuel costs and revenues in Exhibit___(BCH-1), Schedule 15, Fuel Reconciliation.

III. SUPPORTING INFORMATION

Q. WHAT TOPICS DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section, I provide information related to data provided in our application, the selection of the test year and plan year, and the jurisdictional COSS study.

A. Data Provided and Selection of the Test Year

Q. WHAT TOPICS DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section, I will:

- identify the supporting financial information and related fiscal periods that we are providing in connection with the MYRP Forecast; and
- demonstrate that the supporting financial information and related fiscal periods that we are presenting provide appropriate information and facilitate review of our MYRP Forecast.

1. *Overview*

Q. PLEASE DEFINE THE FISCAL PERIODS FOR WHICH FINANCIAL DATA IS PROVIDED IN THIS PROCEEDING.

A. Following the Commission's rules, financial data is provided for 2023 (the most recent fiscal year), 2024 (the projected fiscal year), and 2025 (the test year). In addition, we provide financial data to support the MYRP Forecast. The most recent fiscal year (calendar year 2023) reflects the Company's actual financial results. For the projected fiscal year 2024, actual financial results through June 2024 are provided as rate base data, operating expenses, and revenues. Forecast projections are provided for the remainder of 2024. The MYRP Forecast reflects the Company's most recent available budget data.

All fiscal periods provided in this testimony are adjusted for traditional regulatory adjustments (*e.g.*, charitable donations, etc.).

I also provide schedules showing: the actual unadjusted average rate base consisting of the same rate base components; unadjusted operating income; overall rate of return; the calculation of required income; and the income deficiency and revenue requirements for the most recent fiscal year (2023); the projected fiscal year (2024); and the MYRP Forecast. Separate rate base and income statement bridge schedules for the MYRP Forecast that identify test period adjustments are provided with my testimony.

2. MYRP Forecast

Q. WHAT WAS THE BASE SOURCE FOR THE PROPOSED MYRP FORECAST COSTS?

A. Calendar year 2025 was selected as the test year for this filing using Xcel Energy's most recent available budget data for the first year of the budget cycle. Use of a fully projected calendar test year (2025) is consistent with longstanding practice and precedent in the Company's rate cases before the Commission.

The 2026 plan year reflects year two from the most recent available budget information, of which the 2025 test year is year one. This is consistent with our approach for the 2022-2024 MYRP. Using the same budget vintage for the test year and plan year allows for a consistent MYRP Forecast.

The 2025-2026 Budget is supported in witness Robinson's Direct Testimony, and supporting information is provided in Volume 5 of the Application.

Q. DOES THE COMPANY ANTICIPATE UPDATING SOME OF ITS INFORMATION IN REBUTTAL TESTIMONY?

A. Yes. Consistent with prior cases, we will update certain costs to incorporate updated information. More specifically, as in our 2022-2024 MYRP, we will review the following and update in this case as appropriate:

- Cost of capital to reflect the most currently available data;
- Excess liability insurance reflecting the most currently available data;

- Commission decisions in other dockets that impact this rate case MYRP;
- Current customer count and sales information and expected trends that might indicate that adjustments to the sales and customer counts forecast are needed; and
- Property tax forecasts based upon property tax data that will become available during 2025.

3. Supporting Information and the 2025 Projected Test Year

Q. WHY DOES THE COMPANY USE 2023 AS ITS MOST RECENT FISCAL YEAR INSTEAD OF 2024?

A. Minn. R. 7825.3100, Subp. 10 provides the following definition:

> "Most recent fiscal year" is the *utility's prior fiscal year [here, 2023]* *<u>unless</u>* notice of a change in rates is filed with the commission within the last three months of the current fiscal year *and at least nine months of historical data is available for presentation of current fiscal year financial information*, in which case the most recent fiscal year is deemed to be the current fiscal year. (Emphasis added.)

In this proceeding, the Company's prior fiscal year is 2023, and its current fiscal year is 2024 because the two exceptions to the rule that would instead convert 2024 into the most recent fiscal year are not fulfilled. While the Company is filing this rate case within the last three months of 2024, nine months of actual 2024 data is not "available for presentation." Since that requirement cannot be met, the plain language of the Rule directs the Company to use 2023 as the most recent fiscal year, consistent with the Company's long-standing approach.

Nothing in the Rule requires the Company to delay its filing until additional 2024 data becomes available or to accelerate the availability of the actual data to include nine months of actual data with the filing. Rather, Minn. R. 7825.3100, Subp. 10 requires the Company to treat 2023 as the prior fiscal year and Minn. R. 7825.3100, Subp. 12 requires that we treat 2024 as the projected fiscal year.

Q. IS THIS APPROACH ALSO CONSISTENT WITH THE COMPANY'S PAST PRACTICES THAT HAVE BEEN ACCEPTED BY THE COMMISSION?

A. Yes. In our rate case in Docket E002/GR-12-961, the Administrative Law Judge (ALJ) found that the Company's practice was consistent with its filings in past rate cases and was in compliance with Commission rules. Therefore, the ALJ supported,[5] and the Commission adopted, the Company's use of a fully projected test year. Most recently, we utilized actual 2020 data as the "most recent fiscal year" data in Docket No. E002/GR-21-630, as 2021 actual data was not available for presentation at the time of that filing. There was no issue with that approach in that case.[6]

Q. DOES THE COMPANY'S PRACTICE RESULT IN LESS INFORMATION BEING INCLUDED IN THE FILING?

A. No. The Company filed information for 2023 (the most recent fiscal year), 2024 (the projected year), the unadjusted 2025 test year, the adjusted 2025 test year,

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[5] ALJ Report Findings 866-873 in Docket No. E002/GR-12-961 (July 3, 2013).

[6] In one prior case before the Commission, the Commission issued a rule variance in order to permit a utility to utilize the last full calendar year (2016 data) as the "most recent fiscal year" for a rate case filed in the last two months of 2017. *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota,* ORDER ACCEPTING FILING, SUSPENDING RATES, EXTENDING TIMELINE, AND VARYING RULE, Docket No. G011/GR-15-736 (Dec. 5, 2017). We do not believe a variance is necessary here, just as it has not been necessary in prior NSPM rate cases, because utilizing 2023 data is consistent with the Minnesota Rule under the circumstances of this filing. But if the Commission determines that a variance is necessary, the Company requests a variance under Minn. R. 7829.3200, because (i) the Company began preparing this rate case filing several months before the requisite data was available for 2024, and it would be an excessive burden on the utility to wait to file the case or refile the case when 2024 data is available (and would not align with a calendar year test year); (ii) granting the variance would not adversely affect the public interest, because NSPM has used this approach in the past with the same extensive data, and it has resulted in just and reasonable rates; and (iii) granting the variance would not conflict with standards imposed by law.

and the 2026 plan year. Definitions and financial schedules related to 2023 actual and 2024 projections are included in the following locations.

- Volume 3, Required Information, Section II:
  - Subpart 2, Jurisdictional Financial Summary Schedule, Schedule A-1
  - Subpart 3, Rate Base Schedules, Section A, Schedule A-1
  - Subpart 3, Rate Base Schedules, Section B, Schedule B-2
  - Subpart 3, Rate Base Schedules, Section E, Schedule E, Page 2
  - Subpart 4, Operating Income Schedules, Section A, Schedule A-1
  - Subpart 4, Operating Income Schedules, Section B, Schedule B-1
  - Subpart 4, Operating Income Schedules, Section C, Schedules C-1 and C-3
  - Subpart 4, Operating Income Schedules, Section F, Schedule F, Page 2
  - Subpart 5, Rate of Return Cost of Capital Schedules, Sections A-D;
- Exhibit___(BCH-1), Schedule 7, Comparison of Detailed Rate Base Components;
- Exhibit___(BCH-1), Schedule 8, Comparison of Detailed Income Statement Components.

B. Jurisdictional Cost of Service Study (COSS)

Q. WHAT TOPICS DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section, I will explain the jurisdictional COSS that we prepared for the MYRP Forecast.

Q. PLEASE DESCRIBE THE COMPONENTS OF THE JURISDICTIONAL COSS FOR THE MYRP Forecast.

A. A summary of the jurisdictional COSS for the MYRP Forecast is provided in Schedule 2, Summary of Revenue Requirements. The complete jurisdictional COSS for the MYRP Forecast provided in Schedule 3, COSS Summary, and in Volume 4, Section II, COSS of this filing and includes all the adjustments discussed in my Direct Testimony.

The jurisdictional COSS includes the following financial data input sections for both Total Company and the Minnesota Jurisdiction: (i) capital structure; (ii) cost of capital; (iii) income tax rates; (iv) rate base; (v) income statement; (vi) income tax calculations; and (vii) cash working capital.

Q. PLEASE DESCRIBE THE JURISDICTIONAL COST OF SERVICE SUMMARY SCHEDULES.

A. The jurisdictional cost of service summary for each year of the MYRP Forecast is included as Schedule 3, COSS Summary:

- The Rate Base Summary for the Minnesota jurisdiction is shown on Page 1. It provides the assumed capital structure, including the earned overall rate of return on rate base and the earned ROE. The Rate Base Summary references a calculation of cash working capital, which is detailed in Exhibit___(BCH-1), Schedule 4 (Cash Working Capital), and Volume 4, Section III, Rate Base (Plant), Subpart P10, Cash Working Capital.
- An Income Statement for the Minnesota jurisdiction is shown on Page 2 and Page 3. The income statement shows the determination of total operating income at present authorized retail rates. The Income Statement references calculations for federal and state income taxes, which are detailed on Page 3.

- The Revenue Requirement and Return Summary for the Minnesota jurisdiction is shown on Page 4. It shows the revenue deficiency that needs to be recovered to enable the Minnesota jurisdiction electric operations to earn the requested ROE and the total revenue requirements.

Q. ARE THE REVENUE CONVERSION FACTOR CALCULATION AND THE MINNESOTA COMPOSITE INCOME TAX RATES INCLUDED IN THIS FILING?

A. Yes. The revenue conversion factor calculation is included in Volume 3, Section II.7, Required Financial Information, Other Supplemental Information, Subpart B, Gross Revenue Conversion Factor; and composite income tax rates are included in Volume 3, Section II.4, Required Financial Information, Operating Income Schedules, Subpart C, Income Tax Computation, Schedule C-5.

Q. PLEASE EXPLAIN HOW THE INTEREST DEDUCTION FOR DETERMINING TAXABLE INCOME IS CALCULATED.

A. The amount of interest deducted for income tax purposes is the weighted cost of debt capital multiplied by the average rate base. This is sometimes called "interest synchronization." The MYRP calculation for the interest synchronization is provided in Schedule 3, Cost of Service Summary, line 110.

Q. WHICH SCHEDULES ATTACHED TO YOUR TESTIMONY ARE RELATED TO RATE BASE?

A. I have provided three schedules related to rate base: Schedule 7, Comparison of Detailed Rate Base Components; Exhibit___(BCH-1), Schedules 10a-10b, 2025-2026 Rate Base Adjustment Schedules; and Exhibit___(BCH-1), Schedule

9, Rate Base, CWIP, and ADIT Summary. I discuss these schedules in Section IV, Rate Base and Section VII, Annual Adjustments to the MYRP. Additional comparative rate base schedules are provided in Volume 3, Required Information.

Q. WHICH SCHEDULES TO YOUR TESTIMONY ARE RELATED TO THE INCOME STATEMENT?

A. I have provided two schedules related to the income statement: Schedule 8, Comparison of Detailed Income Statement Components, and Exhibit___(BCH-1), Schedules 11a-11b, 2025-2026 Income Statement Adjustment Schedules. I discuss these schedules in Section V, Income Statement and Section VII, Annual Adjustments to the MYRP. Additional comparative income statement schedules are provided in Volume 3, Required Information.

IV. RATE BASE

Q. WHAT TOPICS DO YOU ADDRESS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I support the reasonableness of the Company's projected 2025-2026 MYRP rate base and identify and explain how the components of the rate base were determined, focusing on the 2025 test year and noting any limited situations where there are differences for the 2026 plan year of the MYRP. I begin by providing the overall rate base calculation and identify its components, then walk through each of the MYRP Forecast components of rate base in turn.

Q. IS THE COMPANY'S PROJECTED 2025 TEST YEAR RATE BASE REASONABLE FOR PURPOSES OF DETERMINING FINAL RATES IN THIS PROCEEDING?

A. Yes. The projected 2025 test year rate base for the Company's Minnesota jurisdiction electric operations was developed using sound ratemaking principles and in a manner similar to prior Company electric rate cases. This is also true of the 2026 plan year.

Q. PLEASE EXPLAIN WHAT RATE BASE REPRESENTS.

A. Rate base primarily reflects the capital costs incurred by a utility to secure plant, equipment, materials, supplies, and other assets, both tangible and intangible, necessary for the provision of utility service, reduced by amounts recovered from depreciation and non-investor sources of capital.

Q. PLEASE IDENTIFY THE MAJOR COMPONENTS OF THE PROJECTED 2025-2026 MYRP RATE BASE.

A. The MYRP rate base is generally composed of the following major items, which I describe in more detail later in my testimony:

- Net Utility Plant;
- Construction Work in Progress (CWIP);
- Accumulated Deferred Income Taxes (ADIT);
- Pre-Funded Allowance for Funds Used During Construction (AFUDC); and
- Other Rate Base.

Q. HOW DOES THE COMPANY CALCULATE RATE BASE?

A. The Company's rate base can be expressed using the following breakdown:

	Original Average Cost of Electric Plant in Service (Plant)
Less:	Average Accumulated Depreciation Reserve (Reserve)
Less:	Average Accumulated Provision for Deferred Taxes (net of accts 281-283 and 190) (ADIT)
Plus:	Average Construction Work in Progress (CWIP)
Plus:	Average Working Capital (Work Cap)
Equals:	Rate Base

In this case, the calculation is as follows, using the average of the beginning of year (BOY) and end of year (EOY) balances for the 2025 test year:

Plant	$25,950,738	Schedule 3, Page 1, Line 23)
Reserve	(11,814,328)	Schedule 3, Page 1, Line 24)
ADIT	(2,262,282)	Schedule 3, Page 1, Line 32)
CWIP	982,733	Schedule 3, Page 1, Line 26)
Other Rate Base	381,131	Schedule 3, Page 1, Line 42)
Rate Base	$13,237,993	(thousands of dollars)

Q. PLEASE DESCRIBE THE SCHEDULES IN YOUR EXHIBIT THAT ARE RELATED TO THE TEST YEAR AVERAGE INVESTMENT IN RATE BASE.

A. Schedule 7, Comparison of Detailed Rate Base, provides a detailed statement of the rate base components. Page 1 provides a comparison of the rate base components for the 2025 test year to the 2024 plan year used in our 2022-2024 MYRP. Page 2 provides the rate base components for the MYRP Forecast.

Schedule 9, Rate Base, CWIP, and ADIT Summary, Page 1 of 4, shows a detailed average rate base by component for the 2025 test year for the Minnesota jurisdiction and Total Company, before and after making proposed test period adjustments. Page 2 shows the 2026 plan year detailed average rate base by component for the Minnesota jurisdiction and Total Company. Page 3 shows the MYRP Forecast average Construction Work in Progress for the Minnesota jurisdiction and Total Company, before and after making proposed test period adjustments. Page 4 shows the MYRP Forecast for accumulated deferred income taxes for the Minnesota jurisdiction and Total Company, before and after making proposed test period adjustments.

Schedules 10a-10b, 2025-2026 Test/Plan Year Rate Base Adjustment Schedules, are bridge schedules showing the 2025-2026 unadjusted rate base, each proposed rate base adjustment, and the resulting proposed 2025-2026 test/plan year rate base.

A. Net Utility Plant

Q. WHAT DOES NET UTILITY PLANT REPRESENT?

A. Net utility plant represents the Company's investment in plant and equipment that is used and useful in providing retail electric service to its customers, net of accumulated depreciation and amortization.

Q. PLEASE EXPLAIN THE METHOD USED TO CALCULATE NET UTILITY PLANT INVESTMENT IN THIS CASE.

A. The net utility plant is included in rate base at depreciated original cost reflecting the simple average of projected net plant balances at the beginning and end of the 2025 test year. Such treatment is consistent with the method employed in the Company's most recent Minnesota electric rate case.

Q. WHAT HISTORICAL BASE DID THE COMPANY USE AS A STARTING POINT TO DEVELOP THE PROJECTED NET PLANT BALANCES FOR THE BEGINNING OF THE 2025 TEST YEAR?

A. The historical base used for the beginning of the 2025 test year was the Company's actual net investment (Plant in Service less Accumulated Depreciation) on the Company's books and records as of June 30, 2024 plus the forecast for the remaining months of 2024. Similarly, the 2026 projected beginning net plant balance is based on the forecasted balance at the end of 2025, as walked forward from the actual net investment as of June 30, 2024.

Q. ON WHAT BASIS WERE NET PLANT BALANCES PROJECTED FOR THE END OF THE 2025 TEST YEAR?

A. The 2025 test year ending net plant balances were determined by applying the data contained in the 2025 capital budget to the above-described beginning test year balances, adjusted for retirements, depreciation, salvage, and removal costs projected to occur during the 2025 test year. The same methodology was utilized to establish 2026 end-of-year projected net plant balance.

Q. WHAT WAS THE AVERAGE NET UTILITY PLANT INCLUDED IN THE 2025 TEST YEAR RATE BASE?

A. The average net utility plant included in the 2025 test year rate base is $14.136 billion, as shown on Schedule 7, Comparison of Detailed Rate Base Components. This is comprised of an average plant balance of $25.951 billion as detailed on Schedule 7, minus an average depreciation reserve of $11.814 billion, also shown by component on Schedule 7.

B. Construction Work In Progress (CWIP)

Q. WHAT IS CONSTRUCTION WORK IN PROGRESS?

A. In Minnesota, CWIP is included as part of the revenue requirement calculation for base rates. CWIP is the accumulation of construction costs that directly relate to putting a fixed asset into use.

Q. HAS CWIP BEEN INCLUDED IN THE 2025 TEST YEAR AND 2026 PLAN YEAR RATE BASE?

A. Yes. CWIP is included in rate base with a corresponding offset of AFUDC (the cost of financing during the period a capital investment is included in CWIP) added to operating income, except where the Company is allowed to earn a current return. The rate base amount reflects a simple average of projected CWIP beginning and ending balances. This is consistent with the method employed in Minnesota and approved by the Commission in the Company's 2022-2024 MYRP and matches the use of an average rate base. The CWIP and AFUDC determinations for rate base are discussed in the Direct Testimony of witness Johnson.

Q. HOW WERE THE 2025 TEST YEAR BEGINNING AND ENDING CWIP BALANCES DETERMINED?

A. The beginning balance for CWIP was the June 30, 2024 historical balance. The beginning CWIP balance was adjusted to reflect projected construction expenditures, AFUDC, and transfers to Plant in Service during the remainder of 2024 and in 2025 to obtain the beginning and ending 2025 test year CWIP balances. These projections were developed from the Company's 2025 capital budget. The same methodology was utilized to establish the 2026 end-of-year CWIP balance.

C. Accumulated Deferred Income Taxes (ADIT)

Q. PLEASE DESCRIBE ACCUMULATED DEFERRED INCOME TAXES.

A. Inter-period differences exist between the book and taxable income treatment of certain accounting transactions. These differences typically originate in one period and reverse in one or more subsequent periods. For utilities, the largest such timing difference typically is the extent to which accelerated income tax depreciation exceeds book depreciation during the early years of an asset's service life. ADIT represents the cumulative net deferred tax amounts that have been allowed and recovered in rates in previous periods.

Q. WHY IS ADIT DEDUCTED IN ARRIVING AT TOTAL RATE BASE?

A. To the extent income taxes recovered in rates are deferred for later payment, they represent a prepayment by customers, a non-investor source of funds. The average projected ADIT balance is deducted in arriving at total rate base to recognize such funds are available for corporate use between the time they are collected in rates and ultimately remitted to the respective taxing authorities.

Q. WHAT AMOUNT OF ADIT WAS DEDUCTED TO ARRIVE AT THE 2025-2026 MYRP TEST YEAR RATE BASE?

A. As shown on Schedule 7, Comparison of Detailed Rate Base Components, $2.262 billion was deducted for the 2025 test year. This amount reflects a simple average of the projected beginning and ending 2025 test year ADIT balances and incorporates Internal Revenue Service (IRS) tax regulations. Specifically, Sec. 1.167(l) of the tax code defines a prorated schedule for the extent average accumulated deferred income taxes can be used to reduce rate base to comply with the tax normalization requirements of the Code when forecast information is used to set rates. Details related to the full MYRP Forecast ADIT are provided in Schedule 9, Rate Base, CWIP and ADIT Summary, on Page 4 of 4, and are discussed in more detail by Company witness Johnson.

D. Pre-Funded AFUDC

Q. WHAT IS PRE-FUNDED AFUDC?

A. AFUDC is the cost of financing during the period a capital investment is included in CWIP. In Minnesota, AFUDC is included as part of the revenue requirement calculation for base rates. Specifically, during construction, AFUDC is calculated and included in the CWIP balance and is also included in operating income as an offset to the revenue requirement. AFUDC is added to the cost of related capital projects and is reflected in rate base when the related capital project is placed into service. Once a project is placed in-service, the recording of AFUDC ceases, and the total capital cost of the project including accumulated AFUDC is recovered through depreciation.

However, certain rate riders in Minnesota (*e.g.*, the TCR Rider and the Renewable Energy Standards (RES) Rider) include a current return on CWIP as part of the revenue requirement calculation for the rider. The capital projects associated with those riders do not include the accumulated AFUDC as part of rate base. Pre-funded AFUDC is needed to offset the accumulated AFUDC to align with the current return on CWIP in a rider.

Q. HOW IS PRE-FUNDED AFUDC TREATED?

A. Pre-funded AFUDC is calculated and credited against the total jurisdictional AFUDC to prevent double counting. This treatment, in effect, reduces the income offset provided by AFUDC and reduces the accumulated AFUDC that is added to rate base when a project is placed into service. The Company tracks

Pre-funded AFUDC and the non-rider AFUDC separately so that Minnesota jurisdictional customers are assured of receiving the entire benefit in lower fixed asset costs during the in-service period for the assets included in rate riders. In this way, we ensure that costs are recovered in the appropriate jurisdictions, pursuant to their specific ratemaking procedures.

Q. HOW DOES THE COMPANY ACCOUNT FOR PRE-FUNDED AFUDC?

A. Pre-funded AFUDC is recorded separately by rate jurisdiction in FERC Account No. 253, Other Deferred Credits, during the construction process as AFUDC is incurred. Pre-funded AFUDC is related to projects recovering a current return on CWIP from customers in Minnesota and wholesale transmission customers who pay our FERC-regulated MISO Attachment O and Schedule 26 rates. Once the associated asset is placed into service, the Pre-Funded AFUDC balance is amortized over the same time period as the associated asset.

Q. HOW HAVE YOU TREATED PRE-FUNDED AFUDC IN THE 2025-2026 MYRP?

A. All Minnesota jurisdictional Pre-funded AFUDC has been directly assigned to the Minnesota jurisdiction, according to the functional class of the associated asset for CWIP, Depreciation Reserve, Plant in Service, and ADIT in rate base, and to depreciation, deferred taxes, and AFUDC on the income statement. Accumulated Pre-funded AFUDC is a reduction to rate base, with the amortization of the Pre-funded AFUDC balance being a reduction to depreciation expense. The deferred taxes associated with Pre-funded AFUDC create a deferred tax asset during construction that flows back as the book amortization is recognized. These Pre-funded AFUDC items are at a jurisdictional level; thus, the offset is made once the rate base and the income statement are jurisdictionalized. The Pre-funded AFUDC recorded and budgeted associated with our MISO transmission tariff have been allocated to Minnesota, North Dakota, and South Dakota jurisdictions based on 12 coincident peak demand. This allocation method is consistent with treatment of the underlying transmission assets and their associated expenses and revenues.

E. Other Rate Base

Q. PLEASE SUMMARIZE THE ITEMS YOU HAVE INCLUDED IN OTHER RATE BASE.

A. Other Rate Base is composed primarily of Working Capital. It also includes certain unamortized balances that are the result of specific ratemaking amortizations, as discussed below in my testimony.

Q. PLEASE EXPLAIN WHAT WORKING CAPITAL REPRESENTS.

A. Working Capital is the average investment in excess of net utility plant provided by investors that is required to provide day-to-day utility service. It includes items such as materials and supplies, fuel inventory, prepayments, and various non-plant assets and liabilities. The net cash requirement (referred to as Cash Working Capital) is shown separately.

Q. HOW WERE 2025-2026 MYRP MATERIALS AND SUPPLIES AND FUEL INVENTORY REQUIREMENTS CALCULATED?

A. The Materials and Supplies average balance included in the MYRP rate base are included on Schedule 3, COSS Summary Page 1, Line 35, for each year of the MYRP Forecast. The MYRP average rate base amount for Fuel Inventory is included on Schedule 3, COSS Summary Page 1, Line 36, for each year of the MYRP Forecast. The Materials and Supplies and Fuel Inventory amounts shown on Schedule 3 Page 1, COSS Summary, are based on the 13-month average balances ending June 30, 2024, the most recent data available.

Q. HOW WERE 2025-2026 MYRP NON-PLANT ASSETS AND LIABILITIES DETERMINED?

A. These balances, as shown on Schedule 3 Page 1, COSS Summary, represent 2025-2026 estimates of these balances. Any book/tax timing differences associated with these items have been reflected in the determination of current and deferred income tax provision and ADIT balances previously discussed. The Non-Plant Assets and Liabilities average balance are included on Schedule 3, COSS Summary Page 1, Line 37, for each year of the MYRP Forecast.

Q. HOW WERE 2025-2026 MYRP PREPAYMENTS AND OTHER WORKING CAPITAL ITEMS DETERMINED?

A. Prepayments and Other Working Capital, such as customer advances and deposits, are based on the actual 13-month average balances as a proxy for the 2025-2026 MYRP. Our nuclear outage amortization is also included in Other Working Capital. The average rate base for nuclear outage amortization is based on the average of the beginning of year and end of year balances. The Prepayments and Other Working Capital average balances are included on Schedule 3, COSS Summary Page 1, Lines 38-40, for each year of the MYRP Forecast. The unamortized balances included in Regulatory Amortizations are based on the amortization schedules as described in Section VII.C of my testimony. Regulatory Amortization average balances are included on Schedule 3, COSS Summary, Page 1, Line 41 for each year of the MYRP Forecast.

Q. How were the MYRP Forecast Cash Working Capital requirements determined?

A. Cash Working Capital requirements have been determined by applying the results of a comprehensive lead/lag study to the projected MYRP Forecast revenues and expenses.

Q. Were the components of the MYRP forecast cash working capital calculated consistent with methods used in the 2022-2024 MYRP?

A. Yes. The current MYRP Forecast cash working capital has been calculated consistent with methods accepted in our most recent completed Minnesota electric rate case.

Q. Please briefly explain how a lead/lag study measures cash working capital.

A. A lead/lag study is a detailed analysis of the time periods involved in the utility's receipt and disbursement of funds. The study measures the difference in days between the date services to a customer are rendered and the revenues for that service are received, and the date the costs of rendering the services are incurred until the related disbursements are actually made.

Q. Has Xcel Energy's lead/lag study been updated since the 2022-2024 MYRP rate case?

A. Yes. The Company has updated the lead/lag study for the calculation of the lead and lag days for all categories through year-end 2023, using the methodology for calculating the lead/lag days consistent with the Company's prior electric and gas regulatory filings. The results of the updated lead/lag study for electric operations are presented in Schedule 4, Cash Working Capital, and incorporated into the Minnesota jurisdiction cash working capital calculations as shown on Schedule 3, COSS Summary, Page 1, Line 34.

Q. WHAT ARE THE CURRENT MYRP FORECAST CASH WORKING CAPITAL AMOUNTS?

A. The amounts included as a reduction in average rate base in the MYRP Forecast are based on the results of our lead/lag study prepared consistently with previous rate cases. The resulting Cash Working Capital amounts are as follows:

- 2025 Test Year: ($87.1 million);
- 2026 Plan Year: ($96.6 million).

Q. HAS THERE BEEN A CHANGE IN THE TEST-YEAR CASH WORKING CAPITAL AMOUNT SINCE THE 2022-2024 MYRP?

A. Yes. The 2025 test year Cash Working Capital balance of $87.1 million represents a $62.5 million decrease compared to the 2024 plan year in the 2022-2024 MYRP of $149.6 million.

Q. WHAT IS THE SOURCE OF THE CHANGE IN CASH WORKING CAPITAL?

A. The change in Cash Working Capital is primarily due to the net changes in the average expense lead and revenue lag days between the two periods. Average revenue lag days increased to 41.25 in 2025 from 39.09 in 2024, meaning the Company's revenues are being collected on average 2.16 days slower in 2025 than in 2024. Conversely, the Company's average expense lead days decreased to 50.45 in 2025 from 57.35 in 2024, meaning that the Company's cash outlay for paying expenses has been reduced by an average of 6.90 days. The longer time in collection of revenues and the faster disbursing of cash has decreased the cash working capital balance to be included as an offset to rate base.

Q. WHAT IS THE SIGNIFICANCE OF NEGATIVE CASH WORKING CAPITAL?

A. A negative cash working capital balance indicates that overall revenue collections occur sooner than the date when the associated costs of service are paid. In other words, on average, more cash requirements are being provided by customers and vendors. The negative cash working capital reduces rate base to compensate customers for funds provided to meet cash working capital requirements. It should be noted that changes in the revenues or expenses could cause the cash working capital calculation to change. The Company will update the 2025-2026 MYRP COSS accordingly through this proceeding.

V. INCOME STATEMENT

Q. WHAT TOPICS WILL YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section, I will support the reasonableness of the Company's proposed MYRP income statements. I begin by providing the overall income statement calculations and identifying their components, then walk through each of the MYRP components of the income statements in turn.

Q. ARE THE COMPANY'S PROPOSED MYRP INCOME STATEMENTS REASONABLE FOR DETERMINING FINAL RATES IN THIS PROCEEDING?

A. Yes. The proposed MYRP income statements for the Company's Minnesota jurisdiction electric operations were developed using sound ratemaking principles in a manner similar to prior Company electric rate cases.

Q. PLEASE IDENTIFY THE MAJOR COMPONENTS OF THE PROJECTED INCOME STATEMENTS.

A. The following are the major components of the MYRP income statements:

- Revenues;
- Operating and Maintenance Expenses;
- Depreciation Expense;
- Taxes;
- AFUDC; and
- Interchange Agreement.

Q. PLEASE DESCRIBE THE SCHEDULES TO YOUR TESTIMONY THAT ARE RELATED TO THE INCOME STATEMENT.

A. Schedules 11a-11b, 2025-2026 Income Statement Adjustment Schedules, are bridge schedules that show the unadjusted income statement, each proposed income statement adjustment, and the resulting proposed income statement for each year of the MYRP Forecast. Schedules 11a-11b also include the revenue deficiency amount for each item included in this schedule.

Schedule 8, Comparison of Detailed Income Statement Components, provides a detailed statement of the income statement components. Page 1 provides a comparison of income statement components for the 2025 test year to the 2024 plan year used in our most recent rate case. Page 2 provides the income statement components for the MYRP Forecast.

A. Revenues

Q. HOW DOES THE COMPANY PRESENT ITS PROJECTED SALES FOR THE MYRP FORECAST?

A. The MYRP sales volumes are supported by witness Levine. Witness Levine discusses the basis for the Company's sales forecasts, including the use of normal weather to develop the Company's projected MYRP sales.

Q. DO RETAIL OPERATING REVENUES REFLECT THE PROJECTED LEVEL OF UNBILLED SALES VOLUMES IN THE MYRP FORECAST?

A. Yes. As witness Levine explains, the projected level of unbilled sales is incorporated into the retail sales forecast on a calendar-month basis. This eliminates the need to reconcile billing-month sales to calendar-month sales by recording unbilled revenues.

Q. HAVE YOU CONSIDERED OTHER OPERATING REVENUES AS AN OFFSET TO THE RETAIL REVENUE REQUIREMENT?

A. Yes. The MYRP Forecast includes items such as revenues from sales to other utilities, certain revenues from wholesale trading activities, wholesale transmission revenues, and specific tariff charges, including service activation fees, reconnection fees, and others. Other operating revenues also include billings to NSPW under the Interchange Agreement. I discuss adjustments to revenues in more detail in Section VII, Annual Adjustments to the MYRP.

Q. HAVE REVENUES AND EXPENSES ASSOCIATED WITH NSPM'S NON-REGULATED BUSINESS ACTIVITIES BEEN EXCLUDED FROM THE MYRP COST OF SERVICE?

A. Yes. We have excluded the revenues and expenses associated with Commission-approved non-regulated business activities (*e.g.*, customer-owned street lighting maintenance and Sherco steam sales to Liberty Paper) from the MYRP cost of service. Because these activities are recorded in below-the-line accounts, they were not included in the MYRP Forecast.

Q. HOW ARE REVENUES AND EXPENSES RELATED TO THE MISO SCHEDULES TREATED IN RATES?

A. Both revenues and expenses related to the MISO schedules are included in the determination of retail rates through either base rates, the fuel clause adjustment (FCA), or the TCR Rider. Base rate recovery, for example, includes both the revenues received from MISO and the expense billings from MISO for Schedules 1 (Scheduling, System Control, and Dispatch Service) and 7 (Firm Point-to-Point Transmission Service). The FCA, for example, includes Schedule 3 (Regulating Reserve). The TCR Rider includes Schedule 26 (Network Upgrade from Transmission Expansion Plan) and 26-A (Multi-Value Project Usage Rate) revenues and expenses. The TCR Rider also includes, for capital projects not regionally shared, an Open Access Transmission Tariff (OATT) Revenue Credit to estimate the revenue that will be collected for the project from wholesale transmission customers.

Q. WHAT ARE WHOLESALE MARGINS?

A. There are two categories of transactions that generate wholesale margins (revenues less costs): asset based transactions; and non-asset based transactions. Asset based transactions are comprised of short-term sales of excess energy or capacity from Company-owned generation assets or power purchase agreements (PPAs) executed to serve our native load customers. The Company executes these asset based transactions through bilateral agreements with specific wholesale customers and through sales directly into the MISO energy market. Sales into the MISO market account for the bulk of these transactions.

Non-asset based transactions are wholesale trading transactions undertaken to obtain margins from purchases and sales of energy or capacity unrelated to meeting the energy needs of our native load customers. The only transactions that qualify as non-asset based transactions are third-party supplied electricity or financial transactions that are not purchased to meet the needs of our retail customers and that are then resold to other utilities or market participants.

Q HOW HAVE ASSET BASED MARGINS BEEN TREATED IN PRIOR RATE CASES?

A. Because asset based margins are created by selling energy or capacity from generating facilities or PPAs paid for by customers, all asset based margins have been credited to customers. In our recent rates cases, the Commission has approved passing the sales margins through to customers using the FCA.

Q. IS THE COMPANY RECOMMENDING ANY CHANGE TO THE TREATMENT OF ASSET BASED MARGINS?

A. No. The Company recommends the same treatment of crediting asset based energy sales margins to customers through the FCA going forward.

Q. HOW HAVE NON-ASSET BASED MARGINS BEEN ADDRESSED IN PRIOR CASES?

A. In our recent rate cases: (i) 100 percent of the non-asset based trading margins were retained by the Company; and (ii) 100 percent of the fully allocated O&M costs and IT system-related costs associated with non-asset based trading margins were excluded from the MYRP and, thus, resulted in a decrease in MYRP operating expenses.

Q. IS THE COMPANY RECOMMENDING ANY CHANGE TO THE TREATMENT OF NON-ASSET BASED MARGINS?

A. No. The Company recommends the same treatment of retaining 100 percent of non-asset based trading margins and excluding 100 percent of the fully allocated O&M and IT costs.

Q. HAS THE COMPANY CONDUCTED A FULLY ALLOCATED COST STUDY OF NON-ASSET BASED TRADING?

A. Yes. The fully allocated O&M and IT cost study adjustment is included in Volume 4, Section VIII Adjustments, Subpart A15, Trading: Non-Asset Based Admin.

Q. IS THE COMPANY RECOMMENDING ANY CHANGE TO NON-ASSET BASED STUDY?

A. Yes, since the study is simply a comparison of the incremental and fully allocated costs and this information is the basis for the adjustment made in this rate case, a schedule is no longer provided with my testimony. All information pertaining to this adjustment is provided in Volume 4, Section VIII Adjustments, Subpart A15, Trading: Non-Asset Based Admin.

Q. UNDER THE COMPANY'S PROPOSALS FOR ASSET BASED MARGINS AND NON-ASSET BASE MARGINS, IS IT NECESSARY TO MAKE ANY TEST OR PLAN YEAR ADJUSTMENTS?

A. The treatment of asset-based and non-asset based margin as described above is incorporated into the test and plan year base data. All asset-based energy margins are shared with customers through the FCA and are excluded from revenue and expenses in the 2025-2026 MYRP. Non-asset based margins are retained by shareholders and are excluded from revenue and expense in the

2025-2026 MYRP. Lastly, the Non-Asset Trading O&M adjustment removes the operating expenses in the income statement for the fully allocated O&M and IT-related costs of non-asset based trading activity.

B. Operating and Maintenance Expenses

Q. HOW DOES THE COMPANY CALCULATE OPERATING EXPENSES?

A. The Company's operating expenses can be expressed using the following breakdown:

Operation and Maintenance Expense (including fuel) (Operating Exp)
\+ Depreciation Expense (Depreciation)
\+ Miscellaneous Amortization Expense (Amortization)
\+ Taxes other than Income Taxes (Other Taxes)
\+ Income Taxes (Income Tax)
= Total Expenses

In this case, the calculation is provided in Table 6 below:

Table 6
Operating Expense

	Item	2025 Test Year Amount ($000s)	2026 Plan Year Amount ($000s)	Exhibit__ (BCH-1), Sch. 3 Reference
	Operating Expense	$2,880,314	$2,935,840	Page 2, Line 74
Plus	Depreciation	914,479	930,236	Page 2, Line 76
Plus	Amortization	44,939	54,152	Page 2, Line 77
Plus	Other Taxes	41,398	29,503	Page 2, Line 88
Plus	Income Tax	(19,505)	7,187	Page 3, Line 134
equals	Total Expense	$3,861,625	$3,956,918	Page 3, Line 138

Q. WHAT ARE THE PRINCIPAL O&M EXPENSE CATEGORIES?

A. The principal expense categories are:

- Fuel & Purchased Energy;
- Production;
- Regional Markets;
- Transmission Interchange;
- Transmission;
- Distribution;
- Customer Accounting;
- Customer Service & Information;
- Sales, Economic Development and Other; and
- Administrative and General.

Q. HOW ARE FUEL AND PURCHASED ENERGY COSTS TREATED?

A. The fuel and purchased energy costs are collected through the FCA. Those costs are fully offset by revenues from the FCA or the Interchange Agreement, as described in Section VIII.A.3 later in my Direct Testimony. Therefore, these costs have no impact on the 2025-2026 MYRP revenue deficiency.

Q. HAS THIS CHANGED SINCE THE 2022-2024 MYRP?

A. No. The treatment of fuel revenues and expenses are consistent with the 2022-2024 MYRP. Consistent with the Commission's November 5, 2019, Order Approving Compliance Filings in Docket No. E999/CI-03-802, we have provided financial schedules that reflect a cost of service with and without fuel revenues and expenses. Where comparisons are made with prior years, we continue to present those financial schedules with fuel revenues and expenses to allow for comparison. Consistent with the Commission's November 5, 2019, Order in Docket No. E999/CI-03-802, and as discussed in greater detail later in my testimony, the rates proposed exclude Fuel Clause Adjustment-related costs.

Q. WHAT ARE PRODUCTION COSTS AND HOW ARE THEY DETERMINED?

A. Production costs are primarily the costs of operating our generating facilities. These costs are budgeted through development of a production budget prepared to serve the combined energy and demand requirements of the NSP System (used for both NSPM and NSPW). Please see the Direct Testimony of witness Capra for further information related to how the Company budgets for the operation and maintenance of our generation fleet.

Q. HOW DOES XCEL ENERGY DEVELOP ITS MYRP FORECAST TRANSMISSION EXPENSE?

A. Transmission expenses are the O&M costs associated with operating and maintaining our system transmission facilities. These costs are budgeted through development of a transmission budget prepared to serve the NSP System (*i.e.*, for both NSPM and NSPW). These costs and their development are detailed in witness Berklund's Direct Testimony.

Q. HOW DOES XCEL ENERGY DEVELOP ITS MYRP FORECAST DISTRIBUTION EXPENSE?

A. Distribution expenses are the O&M costs associated with operating and maintaining our Minnesota distribution facilities. These costs are developed through a distribution budget process that is discussed in the Direct Testimony of witness Mensen.

Q. HOW DOES XCEL ENERGY DEVELOP ITS MYRP FORECAST CUSTOMER ACCOUNTING EXPENSE?

A Customer Accounting O&M costs are associated with meter reading, billing, credit and collections, bad debt expense, contact center, and operational support services. These costs are developed through the Customer Care budget prepared for both the NSPM electric and gas utilities. These costs and their development are detailed in the Direct Testimony of Company witness Nora Lindgren.

Q. WHAT COSTS ARE INCLUDED IN ADMINISTRATIVE AND GENERAL (A&G) EXPENSE?

A. A&G expense includes Information Technology (IT), compensation, office supplies and expenses, and consulting services for officers, executives, and other Company employees properly chargeable to utility operations and not chargeable directly to a particular operating function. Also included in A&G expense are insurance and other costs related to injury or damage claims made by employees or others, employee pensions and benefits, regulatory expenses, general advertising expense, utility rental expense not properly chargeable directly to a particular operating function, and maintenance costs assignable to the customer accounts, sales, and A&G functions.

Q. ARE ANY COSTS RELATED TO CIVIC OR POLITICAL ACTIVITIES (LOBBYING) IDENTIFIED IN THE COST OF SERVICE OR ADJUSTMENTS?

A. No. The Company records all lobbying costs to below-the-line accounting, FERC account 426.4, Expenditures For Certain Civic, Political, and Related Activities. The Company prepares the unadjusted expenses for the test year using queries that restrict the data to only above-the-line accounts (FERC

Accounts 500 through 935). Thus, no adjustment to the cost of service for lobbying costs is required, as these below-the-line amounts are not used in our development of the MYRP cost of service. We have also excluded the portion of organizational dues associated with lobbying activities. Witness Robinson's Direct Testimony addresses our efforts to identify and remove lobbying expenses.[7]

C. Depreciation Expense

Q. WHAT IS THE BASIS OF THE DEPRECIATION RATES AND EXPENSE USED IN THE 2025-2026 MYRP?

A. Depreciation expense for the 2025-2026 MYRP reflects the Company's proposed rates in its Annual Review of Remaining Lives and Depreciation Rates (ARL) for Electric and Gas Production and Gas Storage Facilities and Transmission, Distribution, and General Accounts (TD&G) submitted on September 9, 2024 in Docket No. E002/D-23-356. To the extent these rates are not adopted per the filing, the Company will submit any necessary updates in rebuttal testimony. These adjustments are discussed in Section VII (adjustments 3 and 4). The Company's depreciation expense is discussed in the Direct Testimony of witness Johnson.

D. Taxes

Q. WHAT TAX EXPENSES ARE INCLUDED IN THE 2025 TEST YEAR AND 2026 PLAN YEAR INCOME STATEMENT?

A. We have line items for Property Tax; Income Taxes including Deferred Income Tax, Investment Tax Credits, and Federal and State Income Tax; and Payroll

[7] Charitable contributions, economic development contributions, and Chamber of Commerce dues are other below-the-line expenses that are moved above the line, in part, through adjustments described in Section VII.

Tax. The State and Federal income taxes are calculated in Schedule 3, COSS Study Summary for the 2025 test year and 2026 plan year, Page 3 of 4.

Q. HOW ARE PROPERTY TAXES DETERMINED FOR THE JURISDICTION?

A. Property taxes are determined on a NSPM Total Company basis. The functions are then allocated to the Company's regulatory jurisdictions using the demand allocator for electric production and transmission, the gas design day allocator for gas production, gas transmission is direct assigned by state and distribution is direct assigned by state for both electric and gas. Please see Volume 4, Section III Rate Base (Plant), Subpart P6, Property Tax for more details.

Q. HOW ARE INCOME TAXES DETERMINED FOR THE JURISDICTION?

A. Income taxes are determined based on total before tax book income, tax additions, and deductions which determine deferred income taxes and the resulting taxable income that is used to calculate federal and state income taxes. The federal income tax rate reflects the 21 percent rate effective January 1, 2018 with the enactment of the Tax Cuts and Jobs Act (TCJA). The utilization or generation of net operating losses or tax credits impact both deferred income taxes and federal and state income taxes, which I will discuss in more detail below.

Q. WHAT IMPACT WOULD A FEDERAL TAX RATE INCREASE HAVE ON THE COST OF SERVICE?

A. The specific impacts to the cost of service would depend on the actual legislation that is enacted. However, at a high level, an increase in the corporate income tax rate is expected to increase current and deferred income tax expense and ADIT leading to a net increase in the cost of service. Similarly, a decrease in the corporate income tax rate is expected to decrease current and deferred income tax expense and ADIT leading to a net decrease in the cost of service, consistent with the TCJA impacts on the cost of service.

Q. WHAT DOES THE COMPANY PROPOSE IF INCOME TAX RATES WERE TO CHANGE DURING THE MYRP?

A. The Company would likely need to work with the Commission to seek relief if such a change occurs. In the event of new tax legislation, it is also possible other Minnesota utilities will need similar relief. One option may be to institute a tracker, similar to how the TCJA was addressed in 2018, that would track and defer the difference between the cost of service used to set final base rates in this rate case filing with a cost of service adjusted for any income tax changes. We would then address the net regulatory asset or liability in our next rate case.

Q. PLEASE SUMMARIZE THE RATEMAKING TREATMENT OF NET OPERATING LOSSES (NOLS).

A. The Company continues to follow the resolution of "Tax Normalization and Allowance for Net Operating Losses" from its other recent rate cases, which was reflected in Exhibit 105 in Docket No. E002/GR-10-971. Specifically, the Company will continue to give back to retail customers annually the revenue requirement benefit associated with the utilization of tax deductions and credits carried forward from prior periods.

NOLs require an adjustment that offsets the part of the ADIT rate base reduction that is associated with the accelerated depreciation deductions that have exceeded the Company's taxable income and have, thus, not resulted in deferral of income taxes. That adjustment is needed to keep the Company's rate base consistent with the income tax deductions that the Company has been able to use. Keeping a balance of rate-base reductions resulting from the ADIT and the use of accelerated depreciation deductions is required under federal income tax law as part of "normalization" for both accounting and ratemaking.

The timing of utilization and the carry-forward balances associated with unused deductions and credits will continue to change over time as the Company's revenue and deduction levels change. The annual reporting process, which incorporates actual revenues, deductions, and cost of capital, will continue to be the vehicle to track the utilization and any remaining balances and annually refund any utilization that has not been applied in base rates. The Company is not proposing any changes to that reporting process in this case.

Had this rate treatment not been approved by the Commission, the 2025 test year revenue requirement would be the same. However, if utilization of carried-forward deductions and credits took place outside of a rate case test year, then customers would not receive refunds for the revenue requirement value. Therefore, this treatment protects customers in the event of changes in the utilization of tax deductions and credits, although the Company does not have the same protections if deferred tax assets increase between cases.

Q. PLEASE EXPLAIN HOW THE COMPANY DETERMINES WHETHER DEFERRED TAX ASSETS (DTAS) ARE CREATED OR CONSUMED.

A. The calculation of income taxes determines whether DTAs are created or consumed. After the calculated income tax expense is reduced for allowed NOL deductions or tax credits, the remaining income tax credits and deductions are "carried forward" and can be used to reduce taxes in future years. The federal income tax code and tax regulations dealing with NOLs state that unused deductions carried forward to a future tax year must be utilized before credits. The opposite is true during a time of setup. To the extent the calculated income tax expense is negative, first tax credits, and then depreciation deductions, are reversed, carried forward, and are available for utilization in a future period. This reversal creates a reduction to deferred tax expense, resulting in the creation of a DTA.

In future periods, to the extent the calculated income tax expense is positive, the federal income tax code and tax regulations prioritize that first depreciation deductions that were carried forward, and then credits that were carried forward are utilized to reduce the income tax expense by 80 percent for depreciation deductions and 75 percent for credits. This utilization creates an increase in deferred tax expense, reducing the balance of the DTA. Once all depreciation deductions and credits previously carried forward are utilized, the Company will have returned to a positive tax position. This is normal NOL accounting.

For the purpose of determining the NOL, these income tax calculations are done on an all-inclusive jurisdictional cost of service basis in which rider revenues and rider-related investments are included with non-rider revenues and investments. This approach determines the extent to which the NSPM Electric Utility Minnesota retail jurisdiction is in a tax loss position or in a position to utilize deductions and credits carried forward from previous periods. This approach ensures that any reduction in revenue requirements resulting from the utilization of deductions or credits carried forward from prior periods is returned to customers as soon as it is available in the form of a rate refund or reduction to base rates.

These balances related to unused credits and deductions are reported in the Company's May 1 Jurisdictional Annual Reports, including the (most recent) May 1, 2024 Jurisdictional Annual Report. Separate detailed reporting and the revenue requirement value associated with any utilization was most recently reported on May 31, 2024. By having these annual determinations made on an all-in basis, the jurisdictional cost of service study (JCOSS) includes actual data for both rider recovery and base rate recovery. Any change in rider recovery by the Commission will be incorporated in this process.

Q. HAVE THERE BEEN ANY CHANGES TO HOW THE COMPANY DETERMINES WHETHER DEFERRED TAX ASSETS (DTAS) ARE CREATED OR CONSUMED SINCE THE LAST RATE CASE?

A. Yes. With the passage of the federal Inflation Reduction Act of 2022, the Company is permitted to engage in transactions related to the transfer or sale of tax credits beginning in 2023. Selling PTCs results in a reduction in the amount of DTA created. Selling PTCs will avoid the continued buildup of the DTA, which will result in lower rates for customers as noted in Section II.B. Case Drivers of my Direct Testimony.

Q. WHAT ASSUMPTION IS THE COMPANY MAKING RELATED TO THE AMOUNT OF PTCS IT WILL SELL?

A. The 2025-2026 MYRP cost of service reflects the Company selling all PTCs generated and included in the MYRP Forecast in each respective year.

Q. DO THE DTAS AFFECT THE 2025-2026 MYRP REVENUE REQUIREMENTS?

A. Yes. The Company's 2025-2026 MYRP COSS includes a revenue requirement associated with PTCs carried forward from prior periods to the 2025 test year and the impact of the 2025-2026 MYRP generation or utilization of federal tax credits to be carried forward based on the Company's 2025-2026 MYRP COSS. An accounting for the balances carried forward to the 2025 test year COSS, as well as the documented calculations supporting this revenue requirement impact, can be found in Exhibit___(BCH-1), Schedule 14, Net Operating Loss. It should be noted that any change in the revenues, expenses, or capital structure will cause the income tax calculation to change. This could, in turn, affect the timing of the DTAs being generated or utilized and added to or removed from rate base. In addition, any changes in the timing or the amount of tax credits generated or sold (including all forms of PTCs) could also impact the DTAs being generated or utilized. This includes PTCs associated with our nuclear units. Based on the current uncertainty of the actual PTC value the Company will receive and potential guidance from the IRS, the Company has not included any nuclear PTCs in the MYRP Forecast cost of service. The Company will update the 2025-2026 MYRP COSS accordingly through this proceeding.

Q. WHAT IS THE LEVEL OF RENEWABLE ENERGY RESOURCE PTCS INCLUDED IN THE STATE AND FEDERAL INCOME TAX CALCULATION IN THE 2025 TEST YEAR AND 2026 PLAN YEAR?

A. The MYRP Forecast assumes renewable PTCs, net of transaction costs, rider removals, and interchange for the Company-owned renewable generation as shown in Table 7 below. Please see Volume 4, Section III Rate Base (Plant), Subpart P8-1, Production Tax Credits for more details.[8]

[8] As noted in Section VII.F of my testimony (Rebuttal Adjustments), after the cost of service was completed, we discovered that the solar PTCs had been allocated using the Minnesota jurisdictional demand allocator rather than the Minnesota jurisdictional energy allocator. Table 7 reflects PTCs in the 2025-2026 MYRP prior to the rebuttal adjustment describe in Section VII.F.

Table 7
Production Tax Credits – Renewable Energy Resources

(Amount in $000s)	2025	2026
MN PTC Impact on Rev Req net of I/A	($252,741)	($222,256)

We expect production to begin at repowered wind facilities in 2025. Due to the anticipated in-service date of these projects, the Company is recommending that these projects be recovered through the RES Rider.

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE TREATMENT OF RENEWABLE ENERGY RESOURCE PTCS BETWEEN RATE CASES?

A. In addition to the PTCs included in the RES Rider, the Company continues to recommend that the RES Rider act as a true-up mechanism for the PTCs related to projects already in service and included in base rates as a part of the 2025-2026 MYRP cost of service. We propose that the difference in the dollar value of actual PTCs generated and the amounts included in the MYRP be recorded to the RES Tracker account and either returned to, or recovered from, customers through the RES Rider. This approach meets our understanding of the current regulatory treatment for PTCs.

Q. PLEASE EXPLAIN THE EFFECT OF TAX TREATMENT OF PTCS AND THE REQUIRED REVENUE LEVEL NECESSARY TO COVER THE CHANGE IN OPERATING INCOME.

A. PTCs create a direct reduction (credit) to income tax expense causing a corresponding increase to operating income. Every dollar change in operating income needs a revenue conversion factor to be applied to determine the pre-tax revenue level necessary to achieve the operating income change. The revenue conversion factor calculation is included in Volume 3, Section II.7, Required Financial Information, Other Supplemental Information, Subpart B, Gross Revenue Conversion Factor; and composite income tax rates are included in Volume 3, Section II.4, Required Financial Information, Operating Income Schedules, Subpart C, Schedule C-5.

Q. WHAT IS THE REDUCTION IN REVENUE REQUIREMENTS FOR PTCS REFLECTED IN THE MYRP FINANCIAL STATEMENTS?

A. The reduction in revenue requirements for PTCs, net of transaction costs, rider removals, and interchange is shown in Table 7 above.[9] Support for these calculations is shown in Volume 4, Section III, Rate Base, Subpart P8-1, Production Tax Credits.

Q. PLEASE DISCUSS HOW THE COMPANY PLANS TO CAPTURE AND MAXIMIZE THE BENEFITS OF THE INFLATION REDUCTION ACT OF 2022 (IRA).

A. The Company is working with external advisors, including the Edison Electric Institute (EEI) and the American Gas Association (AGA), to assess the IRA and maximize the benefits for customers. The primary near-term benefits of the IRA are related to extended and expanded production tax credit (PTC) and investment tax credit (ITC) benefits for clean energy resources, along with creating a new PTC for existing nuclear resources. Additionally, as I discussed earlier in my testimony, under the IRA, the Company is permitted to engage in transactions related to the transfer or sale of tax credits beginning in 2023. The Company's business area witnesses also address project benefits in their respective direct testimonies. To the extent the Company continues to identify

[9] As noted above, after the cost of service was completed, we discovered that the solar PTCs had been allocated using the Minnesota jurisdictional demand allocator rather than the Minnesota jurisdictional energy allocator. Table 7 reflects the revenue requirement impact of PTCs in the 2025-2026 MYRP prior to the rebuttal adjustment describe in Section VII.F of my testimony.

additional benefits, they will be addressed in greater detail in future filings as appropriate.

E. AFUDC

Q. WHAT IS AFUDC AND WHAT IS ITS FUNCTION IN THE INCOME STATEMENT?

A. As previously noted, AFUDC is the cost of financing during the period a capital investment is included in CWIP. Once an asset is placed in service, the total cost to construct the asset, including accumulated AFUDC, is recovered through depreciation expense. Witness Johnson's Direct Testimony discusses the role AFUDC plays in allowing utilities to recover their cost of financing. In the income statement, AFUDC is used to offset expenses, thus increasing total operating income, and reducing the revenue requirement. This provides a direct offset to the return requirement associated with the inclusion of CWIP in rate base. Please see Section IV. Rate Base, for a detailed discussion of the relationship between CWIP and AFUDC and a discussion of Pre-Funded AFUDC.

F. Interchange Agreement

Q. PLEASE DESCRIBE THE INTERCHANGE AGREEMENT BETWEEN THE COMPANY AND NSPW.

A. The Company and NSPW operate a single integrated electric generation and transmission system and a single electrical "local balancing authority area." This integrated NSP System jointly serves the electric customers and loads of the Company and NSPW. However, the specific generators and transmission facilities making up the NSP System are owned by the two separate legal entities (the Company and NSPW), with the ownership boundary at the Minnesota/Wisconsin border. The Interchange Agreement is a FERC-approved contractual mechanism that provides a means to share the costs of the integrated NSP System between the Company and NSPW.

Q. PLEASE DESCRIBE THE COSTS AND REVENUES ALLOCATED BETWEEN THE COMPANY AND NSPW UNDER THE INTERCHANGE AGREEMENT.

A. Under the Interchange Agreement, the Company and NSPW share annual system generation (production) and transmission costs. Under the Interchange Agreement formulas, approximately 16 percent of the costs of the Company's system are allocated to NSPW, and approximately 84 percent of the NSPW system costs are allocated to the Company, because approximately 84 percent of the load on the integrated system is the Company load and 16 percent is NSPW load. The exact allocation percentages are determined by the allocation factors updated and filed at FERC annually.

The Interchange Agreement also provides for an allocation of revenues received by the Company and NSPW, such as revenues from transmission services or off-system wholesale sales. Interchange Agreement costs and revenues are budgeted by the Company and NSPW annually. Thus, the Company's budget shows Interchange Revenues, which are revenues that reflect the charges to NSPW for its share of production and transmission assets and associated expenses. Likewise, Interchange Expense reflects the Company's budgeted payments to NSPW for its proportionate share of the costs of generation and transmission assets and associated expenses incurred by NSPW to serve the NSP System needs.

The MYRP Forecast Interchange Revenue and Interchange Expenses have been calculated using 2025-2026 Company and NSPW budget information.

This is consistent with the treatment of Interchange Revenues and Interchange Expenses in our last several rate cases.

Q. PLEASE DESCRIBE THE INTERCHANGE AGREEMENT OFF-SET TREATMENT BEING EMPLOYED IN THE MYRP FORECAST COSS.

A. As discussed earlier, in general, the Interchange Agreement is designed to share system-related production and transmission cost between the two operating companies, NSPM and NSPW. The intent of this sharing is to represent these two company systems as a single joint operation. To equalize the costs across this joint system, each operating company bills the other operating company for their share of the joint costs in general using energy requirements as the basis for sharing variable costs and peak demand as the basis for sharing capital related and other fixed costs.

Q. WHAT SPECIFIC COMPONENTS ARE IMPACTED BY THIS SHARING IN THE 2025-2026 MYRP COSS?

A. The NSPM billings to NSPW for the sharing of NSPM costs appear as other revenues in the MYRP Forecast cost of service. The NSPW billings to NSPM for the sharing of NSPW costs appear as either production or transmission expenses in the MYRP Forecast cost of service. Also, any adjustments being proposed in the case that pertain to production or transmission are developed using the same mechanics.

VI. UTILITY AND JURISDICTIONAL ALLOCATIONS

Q. WHAT TOPICS DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section I will:

- explain, at a high level, why it is necessary for the Company to allocate costs among its affiliates and between the jurisdictions in which it does business;
- describe the utility and jurisdictional allocations that are used in determining the revenue requirement; and
- explain the circumstances of the elimination of the separate Wholesale Jurisdiction, the circumstances that led to the loss of full-service wholesale customers, and the effect of those events, including the results of the Company's Wholesale Customer Study.

Q. WHY IS IT NECESSARY TO ASSIGN OR ALLOCATE COSTS BETWEEN NSPM AND ITS AFFILIATES?

A. Whenever services or facilities are shared between NSPM and an affiliate, it is necessary that the appropriate costs related to those services or facilities be assigned or allocated to the appropriate entity. Company witness Nicole L. Doyle's Direct Testimony explains the allocations for services and facilities shared between NSPM and an affiliate. Additional information regarding this process and the reason for selecting a particular allocator is also included in the Cost Assignment and Allocation Manual (CAAM) submitted with this application as witness Doyle's Exhibit___(NLD-1), Schedule 3.

Q. IS IT NECESSARY TO ASSIGN OR ALLOCATE COSTS BETWEEN NSPM'S ELECTRIC AND GAS UTILITIES?

A. Yes. NSPM operates both an electric utility and a gas utility. Therefore, it is necessary that the appropriate costs related to those services or facilities be assigned or allocated to the appropriate utility.

Q. IS IT NECESSARY TO ASSIGN OR ALLOCATE COSTS BETWEEN JURISDICTIONS?

A. Yes. The Company operates in three jurisdictions: Minnesota, North Dakota, and South Dakota. Thus, it is necessary to allocate or assign costs appropriately between jurisdictions. Previously, costs were allocated or assigned to four jurisdictions: Minnesota, North Dakota, South Dakota, and Wholesale. Beginning in 2014, however, the Company has no full requirements wholesale customers. Therefore, since 2014, costs are allocated between the Company's three retail jurisdictions.

Q. HOW ARE COSTS ASSIGNED AND ALLOCATED?

A. The expense budgets relied upon to develop MYRP income statement items were generally prepared on a functional basis (*i.e.*, Production, Transmission, Distribution, Customer Accounts, Customer Information, Sales, Administrative and General). These functional amounts are directly assigned to the Minnesota jurisdiction electric utility operations where appropriate or allocated based on cost causation.

Detailed records are maintained on a functional basis (*i.e.,* Production, Transmission, Distribution, etc.). The capital budgets, from which the projected plant balances in rate base were developed, are also prepared on a functional basis. These functional amounts are assigned to the appropriate jurisdiction directly or allocated based on the use of such assets in providing electric service in a particular jurisdiction and the underlying elements of cost causation.

Generally, all production plant is allocated to jurisdiction using the jurisdictional demand allocator, with the exception of wind projects, which are allocated using the jurisdictional energy allocator. In addition, production costs are shared with

NSPW under the terms of the Interchange Agreement. The Interchange Agreement tariff approved by FERC specifically requires fixed production assets to be allocated between NSPM and NSPW based on demand.

Fixed production O&M expense is allocated using the jurisdictional demand allocator. In addition, fixed production O&M expense is shared with NSPW under the terms of the Interchange Agreement. The Interchange Agreement requires these costs to be allocated between NSPM and NSPW based on demand.

All variable production O&M expense is allocated to jurisdiction using the jurisdictional energy allocator. In addition, variable production O&M expense is shared with NSPW under the terms of the Interchange Agreement. The Interchange Agreement requires these costs to be allocated between NSPM and NSPW based on energy.

Assignment and allocation of costs is further explained in witness Doyle's Direct Testimony.

Q. HOW ARE THESE ALLOCATION FACTORS DEVELOPED?

A. A summary and description of the allocation factors used to allocate expenses and capital items to the Minnesota jurisdictional electric operations income statement and rate base is contained in Volume 3, Section II.3, Required Financial Information, Rate Base Schedules, Subpart E, Rate Base Jurisdictional Allocation Factors, and Section II.4, Required Financial Information, Operating Income Schedules, Subpart F, Operating Income Jurisdictional Allocation Factors. Plant investments are accounted for in the manner prescribed by the

FERC Uniform System of Accounts. The development of allocation factors is further explained in witness Doyle's Direct Testimony.

Q. HOW ARE FUEL AND PURCHASED POWER COSTS ALLOCATED?

A. Fuel and purchased energy costs are allocated to each jurisdiction using the jurisdictional energy allocator. Purchased demand costs are allocated to each jurisdiction using the jurisdictional demand allocator. In addition, fuel and purchased power costs are shared with NSPW under the terms of the Interchange Agreement. The Interchange Agreement requires fuel and purchased energy costs to be allocated between NSPM and NSPW based on energy. Purchased demand costs are allocated between NSPM and NSPW using demand.

Q. WHAT IS THE WHOLESALE CUSTOMER STUDY?

A. The Wholesale Customer Study, which is provided in Volume 3, Section IV, Other Required Information, Subpart 6, Wholesale Customer Study, shows all wholesale customers being served by the Company (including, but not limited to, full requirements, partial requirements, and market based wholesale customers); types of service being provided to each wholesale customer; costs and revenues associated with each wholesale customer; and a clear showing either that wholesale costs are allocated out of the retail rate case or that the revenues are included in the retail rate case, for all services provided to wholesale customers.

Q. DOES THE WHOLESALE CUSTOMER STUDY EXPLAIN WHY THE COMPANY NO LONGER ALLOCATES COSTS TO A WHOLESALE JURISDICTION?

A. Yes. The Wholesale Customer Study explains that all of our partial requirements and energy only wholesale customers are provided services pursuant to bilateral agreements and also explains the treatment of costs and revenues related to services provided to those customers.

Q. WHAT SERVICES DOES THE COMPANY ANTICIPATE PROVIDING TO PARTIAL REQUIREMENTS WHOLESALE CUSTOMERS DURING THE MYRP FORECAST?

A. During the MYRP Forecast, the Company expects to provide services to wholesale customers in the following categories: asset based energy sales, asset based capacity sales, non-asset based energy and capacity sales, and other wholesale transactions (including interfacing and scheduling services, energy services agreements, and pass through charges).

Services to wholesale customers include interfacing between the customer and MISO, including providing balancing services. Revenues from these customers for services and asset based capacity are included in Other Revenues (*e.g.*, for balancing services). Sales of asset based energy are treated as asset based margins and passed through the fuel clause. We also provide some non-asset based services to these customers (energy and capacity sales using financial instruments). The margins from non-asset based transactions, as well as the fully allocated embedded costs related those activities, are treated as below-the-line activities not included in the MYRP revenue requirements.

Attachment A to the Wholesale Customer Study provides a list of the types of services provided, and the ratemaking treatment for each type of service. Attachment B to the Wholesale Customer Study provides a wholesale customer summary including all current agreements by customer and the expected revenues for the years 2025 to 2026.

Q. WHAT DOES THE WHOLESALE CUSTOMER STUDY DEMONSTRATE WITH RESPECT TO THE TREATMENT OF THESE WHOLESALE TRANSACTIONS IN THE MYRP?

A. After reviewing the services provided to our wholesale customers and the transactions associated with those services, the Company concludes that the ratemaking treatment of these transactions is consistent with past regulatory practice and the requirements of the Commission. Based on the treatment of these transactions, the Company believes that costs and revenues associated with wholesale customers are reflected properly in the MYRP.

VII. ANNUAL ADJUSTMENTS TO THE MYRP

Q. WHAT TOPICS DO YOU ADDRESS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I explain adjustments that affect our proposed MYRP Forecast revenue requirements. These adjustments were identified during our review of the MYRP budget and preparation for this case. An individual adjustment may be related to a previous Commission Order, reflect Commission policy or traditional ratemaking treatment, or may be proposed to address a situation particular to this rate case. In this section, I provide details related to each adjustment and explain why each is necessary in order to present a representative level of rate base or costs in the MYRP Forecast. I also identify where another Company witness provides information to explain and support the adjustment.

Q. HOW ARE THESE ADJUSTMENTS PRESENTED IN YOUR TESTIMONY?

A. First, I present traditional adjustments consistent with treatment in prior cases and existing Commission Policy Statements (Precedential Adjustments) and rate case adjustments specific to this particular case (Rate Case Adjustments). Next, I explain the various amortizations affecting the MYRP (Amortizations), the removal of certain costs and revenues being recovered through riders (Rider Removals), and a group of adjustments that are the result of secondary dynamic calculations in the cost of service model (Secondary Cost of Service Calculations).

Q. PLEASE LIST THE 2025-2026 MYRP ADJUSTMENTS.

A. The following adjustments were made to rate base and the income statement where applicable. Rate base adjustments are shown on Schedules 10a-10b, the 2025 and 2026 Rate Base Adjustment Schedules. Income statement (revenue requirement) adjustments are shown on Schedules 11a-11b, the 2025 and 2026 Income Statement Adjustment Schedules. As a general note, all revenue requirements shown on Schedules 11a-11b, are net of Interchange Agreement billings, where applicable, and capital related revenue requirements are shown calculated at the last authorized rate of return. Exhibit___(BCH-1), Schedule 12, MYRP Adjustment Summary provides adjustment amounts for the MYRP. On this schedule, capital related adjustments are shown calculated at the proposed rate of return. Precedential Adjustments are set forth in Exhibit___(BCH-1), Schedule 13 and Table 8 below.

<u>Rate Case Adjustments</u>

1) Bad Debt Expense
2) CIP Approved Program Levels

3) Depreciation Study: Remaining Life
4) Depreciation Study: TD&G
5) Dues: Chamber of Commerce
6) Excess Capacity Proceeds
7) Incentive Compensation
8) Pension: Discount Rate Expense
9) Pension: Retiree Medical Discount Rate
10) PTC Transferability Costs
11) Transmission ROE

<u>Amortizations</u>

12) Credit Card Fee Tracker
13) NOL Tax Reform Regulatory Amortization
14) Prairie Island EPU Deferred Costs
15) Rate Case Expense
16) Sherco 3 Depreciation

<u>Rider Removals</u>

17) Renewable Connect Removal and Avoided Capacity
18) RES Rider
19) TCR Rider

<u>Secondary Cost of Service Calculations</u>

20) ADIT Pro-Rate – IRS Required
21) Cash Working Capital
22) Change in Cost of Capital
23) Net Operating Loss

A. Precedential Adjustments

Q. PLEASE LIST THE PRECEDENTIAL ADJUSTMENTS INCLUDED IN THE MYRP REVENUE REQUIREMENT CALCULATION.

A. Table 8 below is a list of Precedential Adjustments and their associated revenue requirement impact, based on past rate case precedent and Commission policy:

Table 8
Precedential Adjustments ($000)

Adjustment	2025 Test Year	2026 Plan Year	Workpaper Reference
NSPM-Advertising (Trad)	($3,210)	($3,120)	WP-A1
NSPM-Assn Dues (Trad)	($375)	($358)	WP-A2
NSPM-Aviation	($3,369)	($3,439)	WP-A3
NSPM-Customer Deposits - A&G Expense (Trad)	$37	$37	WP-A5
NSPM-Donations (Trad)	$1,410	$1,427	WP-A6
NSPM-Econ Dev Donations (Trad)	$160	$165	WP-A7
NSPM-Econ Develop (Trad)	($127)	($127)	WP-A8
NSPM-Employee Expenses	($1,768)	($1,804)	WP-A9
NSPM-Foundation Admin	($82)	($82)	WP-A10
NSPM-Incentive Pay_Remove Long Term	($16,531)	($17,641)	WP-A11
NSPM-Monticello EPU Commission Order No Return	($5,582)	($4,371)	WP-A12
NSPM-Nuclear Retention Removal	($1,600)		WP-A13
NSPM-Pension Non-Qualified Removal	($338)	($336)	WP-A14
NSPM-Remove NonAsset Trading Fully Allocated Costs	($2,131)	($2,132)	WP-A15
Sub-Total Precedential	($33,506)	($31,783)	

**Differences between components of deficiency and total due to rounding.*

Q. How does the Company provide support for these Precedential Adjustments?

A. Treatment of the precedential adjustments listed above has not changed from the Commission's Order in previous completed electric rate cases (*e.g.,* Docket Nos. E002/GR-13-868, E002/GR-15-826, and E002/GR-21-630). As such, the Company has provided the adjustments themselves in Schedules to my

Direct Testimony, and support for these adjustments, including a detailed description of each adjustment and supporting materials, in the workpapers identified in Table 8 above. This organization is intended to facilitate the review of and full support for each adjustment within the identified workpaper.

Q. HAVE THERE BEEN ANY CHANGES TO THE LIST OF PRECEDENTIAL ADJUSTMENTS SINCE THE COMPANY'S LAST ELECTRIC RATE CASE?

A. Yes. The Company is no longer making an adjustment to remove 50 percent of "investor relations" expense from the cost of service but requesting recovery of 100 percent of these costs. As discussed in witness Wehner's Direct Testimony, these costs do not benefit investors, but are a necessary cost of doing business as a public utility, and as such are recoverable from customers.

Additionally, the Company is making an adjustment to include 100 percent of the non-lobbying portion of Chamber of Commerce dues in the cost of service, rather than 50 percent as approved by the Commission in the Company's last electric rate case. This adjustment is further supported in Section VII.B.5 below.

Q. WHAT IMPACT DO THESE PRECEDENTIAL ADJUSTMENTS HAVE ON THE COMPANY'S ABILITY TO RECOVER ITS TOTAL COSTS OF SERVICE?

A. Regulatory treatment of these precedential adjustments, combined with the incentive compensation adjustments discussed below, decrease our recovery of our costs of service by approximately $22 to $24 million as shown in Table 9 below. The Company expects to incur these costs over the two years of the MYRP, so the cumulative cost to the Company is $46 million over the two-year MYRP.

Table 9
Regulatory Disallowances ($000)

Adjustment	2025 Test Year	2026 Plan Year	Total
Total Precedential	($33,506)	($31,783)	($65,289)
AIP Above 20% Cap, Env. and Time Based LTI	9,309	9,851	19,160
Total Disallowances	($24,197)	($21,932)	($46,129)

Q. HOW IS THE COMPANY INCORPORATING THESE ADJUSTMENTS INTO THE MYRP FORECAST?

A. The precedential adjustments are combined in one column matching the Total Precedential row in Table 8 above in Schedules 11a–11b, 2025-2026 Income Statement Adjustment Schedules. In total, these precedential adjustments represent a decrease in our rate request compared to our budgeted costs. The detail of the precedential adjustments in bridge schedule format can be seen in Schedule 13, Precedential Adjustment Detail. In addition, as noted above, each respective workpaper referenced above contains a detailed description of the adjustment, including the past precedent and related Commission Orders or Policy Statements.

Q. WITH RESPECT TO ECONOMIC DEVELOPMENT COSTS, HAS THE COMPANY PERFORMED A COST-BENEFIT ANALYSIS TO DETERMINE THAT THE BENEFITS OF THE ECONOMIC DEVELOPMENT PROGRAMS EXCEED THEIR COST TO RETAIL CUSTOMERS?

A. Yes. We completed a cost-benefit analysis supporting the inclusion of economic development costs in the MYRP Forecast. Volume 3, Section IV. Other Required Information, Subpart 8, Economic Development Cost-Benefit

Analysis provides the potential revenue and cost impacts of the addition of one commercial/industrial customer to NSPM's electric system due to economic development programs. The results indicate that the investments made by the Company to support economic development in our community have the potential to provide value to customers as soon as the second year.

B. Rate Case Adjustments

1. Bad Debt Expense

Q. PLEASE DESCRIBE THE BAD DEBT ADJUSTMENT.

A. The original calculation for 2025 bad debt expense was generated during the budget process and is a function of projected revenues multiplied by the bad debt ratio for NSPM. An analysis was performed to update the bad debt expense based upon the revenue deficiency in the 2025 test year and 2026 plan year. An adjustment is needed to incorporate the updated bad debt amount into the revenue requirement, which best reflects test and plan year costs.

This adjustment impacts the MYRP revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 40, column 9,
- Schedule 12, page 1, row 19, columns 5 and 6,
- Volume 4, Section VIII Adjustments, Subpart A16, Bad Debt Expense.

2. Conservation Improvement Program (CIP) Approved Program Costs

Q. PLEASE DESCRIBE THE CIP APPROVED PROGRAM LEVELS ADJUSTMENT.

A. The MYRP Forecast CIP (aka Energy Conservation & Optimization Program) expenses and corresponding revenues have been set at the 2025 level of $166.6 million as approved in the December 1, 2023 Decision of the Deputy

Commissioner of the Minnesota Department of Commerce on the Company's 2024-2026 Energy Conservation and Optimization Triennial Plan (Docket E,G002/CIP-23-92).

Because we make corresponding adjustments to both revenue and expense, this adjustment has no impact on the MYRP Forecast deficiency, as shown on:

- Schedule 11, page 1, row 40, column 10;
- Schedule 12, page 1, row 20, columns 5 and 6;
- Volume 4, Section VIII Adjustments, Subpart A17, CIP Approved Program Levels.

3. Depreciation Study: Remaining Life

Q. PLEASE DESCRIBE THE DEPRECIATION STUDY: REMAINING LIFE ADJUSTMENT.

A. We have adjusted the 2025-2026 MYRP to reflect the proposed rates in the Company's Annual Remaining Lives (Production) filing submitted on September 9, 2024 in Docket No. E002/D-23-356. To the extent these rates are not adopted per the filing, the Company will submit any necessary updates in rebuttal testimony. Support for these changes is provided in Company witness Johnson's Direct Testimony.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 43, column 8;
- Schedule 11, page 1, row 40, column 11;
- Schedule 12, page 1, row 21, columns 5 and 6;
- Volume 4, Section VIII Adjustments, Subpart A18, Depreciation Study: Remaining Life.

Q. IS THE COMPANY MAKING AN ADJUSTMENT RELATED TO REMAINING LIFE FOR COAL GENERATION IN THIS PROCEEDING?

A. No. The Company is not proposing accelerated depreciation for Sherco 3 and King in the 2025-2026 MYRP and therefore, no adjustment is needed. Instead, the Company is proposing that the facilities continue to be depreciated using their currently approved remaining lives and when the facilities are retired, any remaining net book value should be transferred to a regulatory asset and coupled with the Commission-approved weighted average cost of capital (WACC). This approach provides a well-balanced solution that not only ensures the financial stability of the utility but also aligns with broader energy policy objectives. This proposal is consistent with the proposal the Company made in Docket No. E002, E015, E017/CI-23-375. To the extent this proposal is not adopted per the filing in that docket, the Company will submit any necessary updates and make any necessary alternative proposals in rebuttal testimony.

4. Depreciation Study: TD&G

Q. PLEASE DESCRIBE THE DEPRECIATION STUDY: TD&G ADJUSTMENT.

A. We have adjusted the 2025-2026 MYRP to reflect the impact of the Company's TD&G filing submitted September 9, 2024 in Docket No. E,G002/D-23-356. To the extent that these rates are not adopted per the filing, the Company will submit updates in rebuttal testimony. Support for these changes is provided in witness Johnson's Direct Testimony.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 43, column 9;
- Schedule 11, page 1, row 40, column 12;

- Schedule 12, page 1, row 22, columns 5 and 6;
- Volume 4, Section VIII Adjustments, Subpart A19, Depreciation Study: TD&G.

5. Dues: Chamber of Commerce

Q. DOES THE COMPANY'S REQUEST INCLUDE RECOVERY OF ASSOCIATION DUES PAID TO CHAMBERS OF COMMERCE?

A. Yes. The Company has included 100 percent of the membership dues paid to various Chambers of Commerce in Minnesota in the 2025-2026 MYRP. Chambers of Commerce provide an essential link between the Company and the communities it serves, allowing for improved utility service. Because membership in these organizations provides benefits to all utility customers, recovery of membership dues paid to Chambers of Commerce is consistent with the Commission's June 14, 1982 <u>Statement of Policy on Organizational Dues</u>. Chamber of Commerce dues are initially recorded below the line; thus, an adjustment is necessary to include Chamber of Commerce dues in the MYRP Forecast.

This adjustment impacts the MYRP revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 40, column 13,
- Schedule 12, page 1, row 23, columns 5 and 6,
- Volume 4, Section VIII Adjustments, Subpart A4, Dues: Chamber of Commerce.

6. *Excess Capacity Proceeds*

Q. PLEASE DESCRIBE THE EXCESS CAPACITY PROCEEDS ADJUSTMENT.

A. We have adjusted the MYRP Forecast costs to include the budgeted revenues for MISO capacity auction revenues and bilateral capacity contracts. In this case, the Company proposes to carry capacity revenues and expenses in a tracker, similar to the capacity revenue tracker implemented in the Company's last electric rate case. This adjustment establishes the baseline revenue amount in base rates.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 40, column 14;
- Schedule 12, page 1, row 24, columns 5 and 6;
- Volume 4, Section VIII Adjustments, Subpart A20, Excess Capacity Proceeds.

7. *Incentive Compensation*

Q. PLEASE DESCRIBE THE INCENTIVE COMPENSATION ADJUSTMENT.

A. We have adjusted the MYRP Forecast to include the budgeted costs for the long-term incentive (LTI) compensation related to Company achievement of environmental goals and time-based employee retention incentives and exclude the budgeted costs for: (1) any non-corporate incentive plan costs; and (2) all Annual Incentive Plan (AIP) amounts above 20 percent of each individual's base pay. Incentive compensation is discussed in the Direct Testimony of witness Ly.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 40, columns 15-17;
- Schedule 12, page 1, rows 25-27, columns 5 and 6;
- Volume 4, Section VIII Adjustments, Subparts A21, AIP over Cap, A22, Environmental LTI, and A23, Time Based LTI.

8. *Pension Discount Rate Expense*

Q. PLEASE DESCRIBE THE PENSION DISCOUNT RATE EXPENSE ADJUSTMENT.

A. This adjustment reflects the Company's recalculation of its MYRP Forecast pension costs using a five-year average discount rate. The Company determined the five-year rolling average discount rate consistent with Order Point 7 in Docket No. E002/GR-13-868. The pension discount rate is discussed in the Direct Testimony of witness Schrubbe.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 40, column 18;
- Schedule 12, page 1, row 28, columns 5 and 6;
- Volume 4, Section VIII Adjustments, Subpart A24, Pension: Discount Rate.

9. *Pension Retiree Medical Discount Rate*

Q. PLEASE DESCRIBE THE PENSION RETIREE MEDICAL DISCOUNT RATE ADJUSTMENT.

A. The Commission's Order in Docket No. E002/GR-13-868 states the discount rate used to calculate retiree medical benefit costs for ratemaking purposes shall be set to equal the five-year average of the FAS 106-based discount rates. An adjustment is necessary to reflect the use of the five-year average discount rate to calculate retiree medical benefits and reflect the appropriate expense level in the MYRP Forecast. Retiree medical benefits and the discount rate are discussed in the Direct Testimony of witness Schrubbe.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 40, column 19;
- Schedule 12, page 1, row 29, columns 5 and 6;
- Volume 4, Section VIII Adjustments, Subpart A25, Pension: Retiree Medical Adjustment.

10. PTC Transferability Costs

Q. PLEASE DESCRIBE THE PTC TRANSFERABILITY COSTS.

A. With the passage of the federal Inflation Reduction Act of 2022, the Company was permitted to engage in transactions related to the transfer or sale of tax credits beginning in 2023. Selling PTCs results in significant net benefits to customers over time but does result in an immediate cost in the form of transaction costs incurred by the Company. However, the Company expects the benefits of PTC transactions to substantially outweigh the transaction costs over time. The MYRP Forecast includes an adjustment to account for the transfer costs based on the Company's (and others') experience in the transfer market thus far.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 2, row 40, column 20;
- Schedule 12, page 1, row 30, columns 5 and 6;
- Volume 4, Section VIII Adjustments, Subpart A26 PTC Transferability Costs.

11. *Transmission ROE*

Q. PLEASE DESCRIBE THE TRANSMISSION ROE ADJUSTMENT.

A. In Direct Testimony, witness Berklund describes the MISO ROE complaints and the potential impact on transmission revenues and expenses of any final decision from FERC related to MISO ROE Complaints. The Company believes a determination at FERC on this matter should not impact the retail jurisdiction, and the cost of capital should be treated consistently across our rate base; therefore, consistent with the outcome in our last rate case, we are proposing this adjustment to calculate the net transmission revenue credit using the ROE approved by the Commission in this case. For purposes of this filing, the adjustment was prepared based on the last authorized ROE of 9.25 percent. In final compliance, the Company will make an adjustment to reflect the final authorized ROE in this case.

This adjustment includes the impact on Attachment O from the MISO Transmission Formula Rate. An adjustment for Attachment GG and MM is not needed since the amounts are included in the TCR Rider MISO Regional Expansion Criteria and Benefits (RECB) revenue and expenses as discussed in Sections VII and VIII of my testimony. This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 2, row 40, column 21;
- Schedule 12, page 1, row 31, columns 5 and 6;

- Volume 4, Section VIII Adjustments, Subpart A27, Transmission ROE.

C. Amortizations

12. Credit Card Fee Tracker

Q. PLEASE DESCRIBE THE CREDIT CARD FEE TRACKER AMORTIZATION.

A. In the Company's last electric rate case, the Company requested approval to include credit card fees in our base rate structure so that the fees are part of overall O&M rather than passed to customers as individual transaction fees for credit card payment of bills. The Commission approved the Company's proposal to begin waiving credit card fees for customers beginning in 2024.[10] Because this program was new for the Company, we proposed to establish a baseline amount for credit card fees in base rates and track actual costs above or below that baseline for recovery or return to customers in a future rate case. Actual credit card fees in 2024 were approximately $1.3 million compared to the $6.6 million included in base rates for 2024. The Company proposes to return this amount to customers over three years, consistent with the amortization of rate case expenses. I note that the Company does not propose continuing this tracker in this case. Company witness Lindgren's Direct Testimony further discusses waiver of credit card fees and the budgeted amount associated with this waiver in this case.

The adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 2, row 40, column 22;

[10] *In the Matter of the Application by Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E002/GR-21-630, ORDER DENYING PETITION FOR RECONSIDERATION, DENYING PETITION FOR CLARIFICATION, AND GRANTING CLARIFICATION at Order Point 4 (October 6, 2023).

- Schedule 12, page 1, row 34, columns 5 and 6;
- Volume 4, Section VIII Adjustments, Subpart 28, Credit Card Auto Pay.

13. NOL Tax Reform Regulatory Amortization

Q. PLEASE DESCRIBE THE NOL TAX REFORM REGULATORY AMORTIZATION.

A. The Commission's Order in Docket No. E,G999/CI-17-895 approved the Company's proposed amortization level included in the TCJA refund calculation. This is being amortized over 23 years.

The adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 43, column 10;
- Schedule 11, page 2, row 40, column 23;
- Schedule 12, page 1, row 35, columns 5 and 6;
- Volume 4, Section VIII Adjustments, Subpart A29, NOL Tax Reform ADIT ARAM.

14. Prairie Island EPU Deferred Costs

Q. PLEASE EXPLAIN THE ADJUSTMENT NEEDED TO RECOVER THE PRAIRIE ISLAND EXTENDED POWER UPRATE (EPU) DEFERRED COSTS.

A. The Commission's Order in Docket No. E002/GR-13-868 approved the recovery of the abandoned Prairie Island EPU project costs over the remaining life of the plant through an amortization expense. The Order also approved including this unrecovered investment in rate base but limited the return on rate base related to this project to the weighted cost of debt.

The amortization and rate of return adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 43, column 11;
- Schedule 11, page 2, row 40, column 24;
- Schedule 12, page 1, row 36, columns 5 and 6;
- Volume 4, Section VIII Adjustments, Subpart A30, PI EPU Recovery.

Q. PLEASE DESCRIBE THE PRAIRIE ISLAND EPU ADJUSTMENTS INCLUDED IN THE 2025-2026 MYRP COSS IN MORE DETAIL.

A. First, the various rate base and income statement components related to the amortization of this deferred cost are input as an adjustment to the cost of service. This results in the calculation of the overall revenue requirement associated with this project. Embedded in these calculations is a computation of return on rate base at the overall weighted cost of capital (debt and equity). To adjust for the ordered weighted cost of debt return requirement, the Company computes the revenue requirements associated with the weighted cost of equity and includes the result of this calculation as Other Revenues to reduce the deficiency by this amount. If the return on equity component of the WACC are adjusted during this case, this adjustment will require a recalculation to reflect those changes.

15. Rate Case Expense

Q. PLEASE DESCRIBE THE RATE CASE EXPENSE AMORTIZATION.

A. The Company is requesting authorization to recover a total of $4.9 million in rate case costs. We are requesting recovery of these costs over the three-year period 2025-2027, consistent with past practice in electric and gas rate cases.

Q. PLEASE DESCRIBE HOW RATE CASE EXPENSE WAS ESTIMATED.

A. The rate case expense budget was developed by first reviewing actual expenses incurred in our 2022-2024 electric rate case. We built the 2025 rate case budget based upon a combination of our plans for outside experts, expected regulatory and legal fees, and estimates for administrative costs such as required notices.

Q. HOW IS THIS ADJUSTMENT IMPACTING THE MYRP FORECAST REVENUE REQUIREMENTS?

A. This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 2, row 40, column 25;
- Schedule 12, page 1, row 37, columns 5 and 6;
- Volume 4, Section VIII Adjustments, Subpart A31, Rate Case expenses.

16. Sherco 3 Depreciation

Q. PLEASE DESCRIBE THE SHERCO 3 DEPRECIATION DEFERRAL AMORTIZATION.

A. The Commission's Order in Docket No. E002/GR-12-961 required the Company to defer the depreciation expense incurred for Sherco 3 during the extended repair outage following the 2011 catastrophic event and amortize it over the remaining life of the plant.

The adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 43, column 12;
- Schedule 11, page 2, row 40, column 26;
- Schedule 12, page 1, row 38, columns 5 and 6;

- Volume 4, Section VIII Adjustments, Subpart A32, Sherco 3 Depreciation Deferral.

D. Rider Removals

Q. PLEASE DESCRIBE THE PURPOSE OF THE RIDER REMOVALS.

A. As previously noted, the Company is removing from base rates all costs it is continuing to recover through riders. Rider costs removed from base rates include costs for rider-eligible projects that are ongoing after the conclusion of the MYRP; certain types of variable costs; and costs for certain ongoing rider programs. Conversely, some portions of rider-eligible projects – such as internal labor – remain in base rates because the Commission does not consider those project components to be rider-eligible. The discussion below demonstrates that the Company is appropriately removing rider costs from base rates.

Q. FOR RIDER-ELIGIBLE PROJECTS WITH AN INTERNAL LABOR COMPONENT, HOW DOES THE COMPANY CALCULATE THE INTERNAL LABOR COMPONENT THAT WILL REMAIN IN BASE RATES?

A. The Company determines the percentage of total CWIP expenditures on a project to date that consists of internal labor and applies that percentage to the forecasted CWIP expenditures. From an O&M perspective, the Company reviews the budget data and identifies the internal labor cost types. The rider removal adjustment excludes these components from project costs, thereby leaving the internal labor in base rates.

*17. Renewable*Connect Removal and Avoided Capacity*

Q. PLEASE DESCRIBE THE RENEWABLE*CONNECT REMOVAL AND AVOIDED CAPACITY ADJUSTMENT.

A. The Renewable*Connect program is a stand-alone retail service program with discrete revenues, purchase power contracts, and operating expenses. We have excluded Renewable*Connect revenues and associated expenses from our MYRP Forecast revenue requirements determination.

Renewable*Connect is a voluntary renewable energy program that gives customers an option to purchase renewable energy to meet all of their energy needs. Customers can choose to subscribe to a five- or ten-year term. A customer subscribing to Renewable*Connect is charged the Renewable*Connect price in lieu of the fuel clause pricing, which is based on the Company's current mix of energy resources.

Including Renewable*Connect as part of a utility's resource mix means that the utility avoided building or purchasing from other sources. The kWh cost of renewable energy purchased by a utility includes a capacity factor or value which would otherwise have been included in the utility's base rates and paid by all customers because all customers benefit from the capacity. This capacity credit is subtracted from the Renewable*Connect rate because it is a cost that should be shared by all customers, rather than only by Renewable*Connect customers. The Direct Testimony of Company witness Nicholas N. Paluck further supports the development of the Renewable*Connect avoided capacity credit.

The net of these adjustments impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 2, row 40, column 27;
- Schedule 12, page 1, row 41, columns 5 and 6;

- Volume 4, Section VIII Adjustments, Subpart A33, Renewable Connect.

18. RES Rider

Q. IS THE COMPANY PROPOSING CONTINUED USE OF THE RES RIDER DURING THE MYRP?

A. Yes. As I describe in detail in Section VIII, Costs Recovered in Riders and Trackers, we propose continued use of the RES Rider during the MYRP for the projects that will not be placed in-service as of December 31, 2024.

Q. PLEASE DESCRIBE THE RES RIDER REMOVAL ADJUSTMENT.

A. The RES Rider removal adjustment removes all costs and PTCs from the MYRP forecast jurisdictional cost of service for the projects that we propose will stay in the rider after the implementation of final rates in this case. The RES Rider adjustment ensures no double recovery of these costs.

For PTCs related to energy production at other Company-owned wind farms currently and proposed to be included in base rates, we propose to continue the true-up to actual PTCs in the RES Rider. These wind farms include Pleasant Valley Wind Farm, Borders Wind Farm[11], Courtenay Wind Farm, Blazing Star I Wind Farm, Foxtail Wind Farm, Lake Benton Wind Farm, Blazing Star II Wind Farm, Crowned Ridge Wind Farm, Jeffers Wind Farm, Community Wind North Wind Farm, Mower Wind Farm, Freeborn Wind Farm, Dakota Range Wind Farm, Grand Meadow Wind Repower, Nobles Wind Repower, and

[11] The PTCs for the original Pleasant Valley Wind Farm and Border Wind Farm are included in base rates and will be included in the RES rider PTC true up. All PTCs earned after repowering these facilities are removed in the rider removal adjustment and will remain in the RES rider after the implementation of final rates in this rate case.

Northern Wind Farm. Finally, should the Company sell any Renewable Energy Credits (RECs), the proceeds from those sales would be shared with customers through the RES Rider.

Q. WHAT COSTS ARE INCLUDED IN THE RES RATE RIDER REMOVAL ADJUSTMENT?

A. This adjustment includes project costs and PTCs for the incremental costs associated with two wind repower projects (Pleasant Valley Wind Farm and Borders Wind Farm), as well as the three Sherco Solar projects, Sherco Battery, and RES Rider present revenue associated with these items, which are proposed to be included in the RES Rider after the implementation of final rates. Costs or revenues associated with the PTC true-up and REC sales occur only on an actual basis and, as such, require no adjustment to the MYRP Forecast.

This adjustment decreases the MYRP Forecast rate base and expense but has a net zero impact on the MYRP Forecast revenue requirements, as we expect full recovery in the RES rider. The rider removal impacts the MYRP Forecast rate base and revenue requirements as shown on:

- Schedule 10, page 1, row 43, column 13;
- Schedule 11, page 2, row 40, column 28;
- Schedule 12, page 1, row 42, columns 5 and 6;
- Volume 4, Section VIII Adjustments, Subpart A34, Rider: RES.

19. TCR Rider

Q. IS THE COMPANY PROPOSING CONTINUED USE OF THE TCR RIDER DURING THE MYRP?

A. Yes. As I describe in detail in Section VIII, Costs Recovered in Riders and Trackers, we propose continued use of the TCR Rider during the MYRP for the projects that will not be placed in service as of December 31, 2024 and MISO RECB Schedule 26 and 26A revenues net of expenses.

Q. PLEASE DESCRIBE THE TCR RIDER REMOVAL ADJUSTMENT.

A. The TCR Rider removal adjustment removes all costs and revenues from the MYRP Forecast jurisdictional cost of service with the exception of internal labor on all rider projects, Advanced Distribution Management System (ADMS) software maintenance O&M costs, and MISO RECB Schedule 26 and 26A net revenues. We are also seeking approval to include the Bayfront to Ironwood and Brookings Second Circuit projects, as well as Hosting Capacity and Participant Compensation costs in the TCR. We proposed to include these project costs and revenues in the TCR Rider and to continue cost recovery for these projects in the rider after the implementation of final rates in this case. The TCR Rider MYRP Forecast adjustment ensures no double recovery of these costs.

This adjustment decreases the MYRP Forecast rate base and expense but has a net zero impact on the MYRP Forecast revenue requirements, as we expect full recovery in the TCR Rider. The rider removal impacts the MYRP Forecast rate base and revenue requirement as shown on:

- Schedule 10, page 1, row 43, column 14;
- Schedule 11, page 2, row 40, column 29;
- Schedule 12, page 1, row 43, columns 5 and 6;
- Volume 4, Section VIII Adjustments, Subpart A35, Rider: TCR.

Q. DOES THE COMPANY COORDINATE THE TCR RIDER REMOVAL WITH ITS TCR RIDER FILINGS?

A. Yes. With each filing, we work to ensure coordination between the rate case MYRP and our TCR Rider filing. However, we note that rate case and rider filings calculate revenue requirements using different rate base averaging methodologies and certain inputs in the rider are required to use historically-approved values. Therefore, even though the underlying data is aligned, there are typically variances in the revenue requirement calculations.

E. Secondary Cost of Service Calculations

20. ADIT Pro-Rate – IRS Required

Q. PLEASE DESCRIBE THE ADIT PRO-RATE ADJUSTMENT THAT IS REQUIRED BY THE IRS AND INCLUDED IN THESE SECONDARY CALCULATIONS.

A. In general, the IRS tax regulations in Sec. 1.167(l) define a pro-rated schedule for the extent average accumulated deferred income taxes can be used to reduce rate base to comply with the tax normalization requirements of the tax code when forecast information is used to set rates. Given that the Company's MYRP filing utilizes forecast test year and plan year data, this condition applies. This has been supported by a number of Private Letter Rulings (PLRs) issued by the IRS. In addition, FERC approved the pro-ration logic included in the Company's Attachment O-NSP transmission formula rate of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff in Docket No. ER18-2322-000.

This secondary calculation limits the ADIT deduction from rate base by applying the IRS defined pro-rate method to only the forecast entries to this balance. Support for this calculation is included in Volume 4, Section VIII Adjustments, Subpart A36, ADIT Prorate for IRS. The IRS requirements for this adjustment are described in more detail in the Direct Testimony of Company witness Johnson.

The adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 43, column 15;
- Schedule 11, page 2, row 40, column 30;
- Schedule 12, page 1, row 46, columns 5 and 6;
- Volume 4, Section VIII Adjustments, Subpart A36, ADIT Prorate for IRS.

21. Cash Working Capital

Q. PLEASE DESCRIBE THE CASH WORKING CAPITAL ADJUSTMENT BEING MADE AS A SECONDARY CALCULATION.

A. As discussed earlier in Section IV.E, Other Rate Base, the Company has incorporated a secondary calculation to apply the various revenue lead days and expense lag days to the various income statement components to result in the appropriate cash working capital rate base adjustment. The adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 43, column 16;
- Schedule 11, page 2, row 40, column 31;
- Schedule 12, page 1, row 47, columns 5 and 6;
- Volume 4, Section VIII Adjustments, Subpart A37, Cash Working Capital Adjustment.

22. *Change in Cost of Capital*

Q. PLEASE DESCRIBE THE IMPACT OF THE CHANGE IN THE COST OF CAPITAL ADJUSTMENT.

A. The change in the cost of capital adjustment is the effect of the changes in the overall cost of capital between the cost of capital (also referred to as the overall rate of return, or ROR) being requested in this case for each year of the MYRP and the effective cost of capital authorized in Docket No. E002/GR-21-630. Table 10 below provides the requested rate of return in this case, and the difference in the rate of return for each year of the MYRP forecast relative to the effective 2024 rate of return of 6.95 percent authorized in Docket No. E002/GR-21-630.

Table 10
Proposed Rate of Return

	2025 Test Year	2026 Plan Year
Proposed Rate of Return	7.56%	7.55%
Difference relative to 6.95%	0.61%	0.60%

On Schedules 11a-11b, 2025-2026 Income Statement Adjustment Schedules, the revenue deficiencies for the base data and all other adjustments are calculated at the 6.95 percent overall cost of capital. This adjustment calculates the required operating income resulting from the change in the overall cost of capital applied to the requested rate of return.

We calculated the revenue deficiencies in this manner so that changes, if any, in the overall cost of capital that occurs during the duration of the rate case do not affect the revenue requirements for each adjustment. The adjustment reflects both the change in the stated ROE from 9.25 percent in our 2022-2024 MYRP to 10.30 percent (for final rates only) in this MYRP, as well as the changes in short-term and long-term debt.

The impact of these adjustments on the MYRP Forecast revenue requirements are shown on:

- Schedule 11, page 2, row 40, column 32;
- Volume 4, Section VIII Adjustments, Subpart A39, Change in Cost of Capital.

23. Net Operating Loss

Q. PLEASE DESCRIBE THE COMPANY'S NET OPERATING LOSS POSITION.

A. The NSPM income tax determination was in a NOL position through 2018. This means that more deductions existed in the current period than are needed to bring current taxable income to zero. The Company still has federal tax credits that have been deferred and tracked for use in future periods. The Company worked with the Department on this issue, which resulted in a process for reporting these deferred balances and returning to customers the revenue requirement reduction associated with the utilization of these deferred balances in the form of a refund or as a reduction to base rates. NOLs, unused tax credits, and the associated ratemaking treatment are discussed in detail earlier in my testimony in Section V. D. Taxes.

Q. IS THE COMPANY PROPOSING AN ADJUSTMENT TO BASE RATES RELATED TO NOLS IN THIS CASE?

A. No. The Company was able to utilize the remainder of the deductions previously deferred and currently no DTA is generated in the MYRP. As noted previously in my testimony, any changes in the revenues, expenses, or capital structure will cause the income tax calculation to be changed. This could, in turn, affect the timing of the DTAs being generated and added to rate base.

Q. IS THE COMPANY PROPOSING AN ADJUSTMENT TO BASE RATES RELATED TO DEFERRED TAX CREDITS IN THIS CASE?

A. Yes. The Company is utilizing previously deferred federal tax credits during the 2025-2026 MYRP and due to PTC market sales of federal tax credits earned during the year, the DTA is decreasing in each year of the MYRP. As noted previously in my testimony, any changes in the revenues, expenses, or capital structure will cause the income tax calculation to be changed. This could, in turn, affect the timing of the DTAs being generated or consumed and added to or removed from rate base.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 43, column 17;
- Schedule 11, page 2, row 40, column 33;
- Schedule 12, page 1, row 48, columns 5 and 6;
- Exhibit___(BCH-1), Schedule 15, Net Operating Loss;
- Volume 4, Section VIII Adjustments, Subpart A38, Net Operating Loss.

F. Rebuttal Adjustments

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I provide details related to adjustments we identified during our final quality assurance reviews performed just prior to this filing. These adjustments reflect changes that we identified after we finalized our cost of service and rate design that we were not able to incorporate due to timing constraints. Consistent with prior rate cases, we propose to incorporate these adjustments into interim rates as applicable, and to update the MYRP Forecast revenue requirement for final rates when we file rebuttal testimony.

24. Distributed Intelligence

Q. PLEASE DESCRIBE THE REBUTTAL ADJUSTMENT RELATED TO DISTRIBUTED INTELLIGENCE.

A. The Company was completing validation of the revenue requirement and identified one non-NSPM distributed intelligence project that was inadvertently included in the MYRP Forecast. The removal of this project will decrease the overall revenue requirement deficiency by approximately $0.2 million in 2025 and 2026. Our interim rate petition does not include distributed intelligence projects, and we will remove the $0.2 million from the MYRP Forecast in rebuttal testimony. Support for this adjustment can be found in Volume 4, Section IX Interim, Subpart Interim Adj 12, Distributed Intelligence Rebuttal.

25. Solar Production Tax Credits - Allocation

Q. PLEASE DESCRIBE THE REBUTTAL ADJUSTMENT RELATED TO SOLAR PRODUCTION TAX CREDITS.

A. The Company was completing validation of the allocation of tax credits among jurisdictions and identified that solar PTCs had been allocated using the Minnesota jurisdictional demand allocator. The Company should have allocated solar PTCs consistent with the RES Rider based on the Minnesota jurisdictional energy allocator due to their variable nature. The adjustment that will be included in rebuttal testimony is shown in Volume 4, Section III Rate Base, Workpaper P8-1, Production Tax Credits. This adjustment would add approximately $69,000 to the 2025 test year and $136,000 to the 2026 plan year in rebuttal testimony. The Company did not make an adjustment to interim rates.

26. TCR O&M

Q. PLEASE DESCRIBE THE REBUTTAL ADJUSTMENT RELATED TO TCR O&M.

A. After the cost of service was completed, we discovered that the TCR rider O&M removal adjustment was inadvertently removed from the wrong FERC account. This has no impact on the MYRP Forecast revenue requirement deficiency or interim rates since the rider removal amounts are based on the costs and jurisdictional allocations in the rider filing. Therefore, our cost of service will be corrected in rebuttal for final rates. However, the correction of these cost assignments as between FERC accounts affects the depiction of O&M cost drivers in the case. As a result, Schedule 6, Detailed Case Drivers, has been adjusted to reflect the correct FERC accounting as noted in the Tale 11 below.

Table 11
TCR O&M Increase/(Decrease) by FERC Account
($ in thousands)

FERC Account	2025 Test Year	2026 Plan Year	Total
557	$580	$1,595	$2,175
565	($580)	($1,595)	($2,175)
581	($80)	($88)	($168)
588	$17,626	$17,666	$35,292
597	($1,220)	($834)	($2,054)
902	($16,327)	($16,745)	($33,072)
909	$1	$1	$2
Net Change in Operating Expenses	$0	$0	$0

27. *Information Technology Costs to Support EV Programs*

Q. PLEASE DESCRIBE THE REBUTTAL ADJUSTMENT RELATED TO IT CAPITAL ADDITIONS AND O&M RELATED TO EV PROGRAMS.

A. In the Company's 2023 Transportation Electrification Plan (TEP), the Commission approved the Company's proposed IT costs of $2.4 million in capital expenditures and $0.9 million in O&M expenditures for the period 2024-2027, modified to be consistent with the EV programs approved in the TEP.[12] After the cost of service was completed, we discovered that a portion of these approved IT capital costs for 2025 and 2026 were inadvertently excluded from the MYRP budget in this case. The capital investments included in the MYRP are described in the Direct Testimony of witness Mensen and the O&M costs are described in the Direct Testimony of witness Robinson. Our cost of service will be updated to include these approved capital and O&M costs in rebuttal.

VIII. COSTS RECOVERED IN RIDERS AND TRACKERS

Q. WHAT TOPICS DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section, I present our proposed treatment of costs recovered in riders and trackers during the MYRP period, including riders that we propose to continue to use and costs we propose to move to base rates. I provide detailed information supporting the adjustments to the MYRP Forecast that I presented in Section VII of my testimony.

Q. WHAT RIDER MECHANISMS ARE CURRENTLY USED BY THE COMPANY?

A. The Company currently uses seven cost recovery riders:

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[12] *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*, Docket No. E002/M-23-452, ORDER APPROVING XCEL ENERGY'S 2023 TRANSPORTATION ELECTRIFICATION PLAN WITH MODIFICATIONS, Order Points 18 and 19 (May 9, 2024).

- Renewable Energy Standards (RES) Rider;
- Transmission Cost Recovery (TCR) Rider;
- Renewable Development Fund (RDF) Rider;
- Conservation Improvement Program (CIP) Rider;
- State Energy Policy (SEP) Rider;
- Renewable*Connect Rider; and
- Fuel Clause Adjustment Rider (FCA).

Q. WHAT IS THE COMPANY PROPOSING WITH RESPECT TO THE TREATMENT OF COSTS RECOVERED THOUGH RATE RIDERS?

A. As discussed in greater detail below, we propose to:

- Continue use of the RES Rider for recovery of incremental costs for two repowered wind projects (Pleasant Valley Wind Farm and Borders Wind Farm), as well as the three Sherco Solar projects and Sherco Battery. We also propose to include PTCs associated with these wind and solar projects and the PTC true-up for other Company-owned wind projects in base rates in the RES Rider. Finally, we propose to share with customers potential proceeds related to any RECs the Company may sell in the future after the implementation of final rates in this case. All current and proposed rider projects and revenue credits will be collected through the RES Rider during the interim rate period.
- Continue use of the TCR Rider, with costs for ADMS, AMI, FAN, LoadSeer, and the Time of Use (TOU) Pilot as well as the proposed Bayfront to Ironwood and Brookings Second Circuit projects and Hosting Capacity and Participant Compensation costs and MISO RECB Schedule 26 and 26A net revenues to continue to be included in the rider

after implementation of final rates in this case. All current and proposed rider projects and revenue credits will be collected through the TCR Rider during the interim rate period.

- Continue use of the RDF Rider, CIP Rider, Renewable*Connect Rider, and the FCA in their current forms.
- Transition Windsource Rider customers to the Renewable*Connect Rider and discontinue use of the Windsource Rider as of March 2024.
- Discontinue use of the SEP Rider with the implementation of interim rates with this rate case on January 1, 2025.

In the following subsections of my testimony, I will address our proposed rate case treatment for each of these riders in detail and discuss how the Company ensures there is no double recovery of these costs.

Q. WHAT IS THE COMPANY'S BASE RATE REVENUE REQUIREMENT EXCLUSIVE OF RIDER ROLL-INS?

A. Our proposed total revenue requirement in 2025 and 2026, including our proposed increase in base rates, is approximately $3.0 billion in 2025 and $3.2 billion in 2026, as shown in Table 12 below.

Table 12
Total Cost Recovery Including Riders

Recovery Method	2025 Test Year ($ in Thousands)	2026 Plan Year ($ in Thousands)
Present Revenues	$3,666,148	$3,725,121
Cumulative Rate Increase	353,253	490,740
Proposed Revenues	4,019,401	4,215,862
Less: Rider Revenue included in present revenue		
CIP Rider	33,503	31,952
FCA Rider	891,200	891,200
RDF Rider	30,933	40,411
RES Rider	14,189	11,999
Total Rider Revenue included in present revenue	969,825	975,562
Net Base Rate Revenue Requirement	$3,049,576	$3,240,300

Rate rider recovery estimates are preliminary, are subject to change, and are also subject to the Commission's decisions in individual rate rider dockets. We provide this information so that the Commission, parties, and our customers can understand the combined impact of our requests.

A. Rider Recovery

1. RES Rider

Q. WHAT IS THE RES RIDER?

A. The RES Rider is authorized by Minn. Stat. § 216B.1645, subd. 2a for the recovery of a utility's investments, expenses, or costs associated with facilities constructed, owned, or operated by a utility that satisfy the Minnesota Renewable Energy Standard.

a. RES Rider Projects

Q. WHAT COSTS ARE CURRENTLY INCLUDED IN THE RES RIDER?

A. The Commission's Order in Docket No. E002/M-23-454 approved our provisional RES Rider rate reduction reflecting the roll in of projects as proposed in the last rate case (Docket No. E002/GR-21-630) and request to recover the costs of the following projects in the RES Rider:

- Northern Wind Farm;
- Nobles Re-Power Wind Farm;
- Grand Meadow Re-Power Wind Farm;
- Pleasant Valley Re-Power Wind Farm;
- Borders Re-Power Wind Farm;
- Sherco Solar I&II;
- Sherco Solar III;
- Sherco Battery;
- PTCs for all wind farms and solar above;
- PTC true up for wind farms included in base; and
- REC sales proceeds.

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE RES RIDER DURING THE MULTI-YEAR RATE PLAN?

A. As described earlier, we propose to:

- Move Grand Meadows Wind Re-Power, Nobles Wind Re-Power, and Northern Wind Farm projects from RES Rider recovery to base rate recovery coincident with implementation of final rates in this rate case;
- Continue recovery of costs and PTCs on Borders Wind Re-Power and Pleasant Valley Wind Re-Power, as well as the proposed Sherco Solar I,

II & III and Sherco Battery projects in the RES Rider;

- In the RES Rider, true-up actual PTCs related to energy production for all wind farms currently in or proposed to roll into base rates compared to the amount included in base rates; and
- Include in the RES Rider customers' share of potential proceeds related to any RECs the Company may sell in the future.

These costs are fully supported in our 2023 RES Rider petition filed in Docket No. E002/M-23-454, which is pending Commission review and approval or will be included in a future filing.

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S REQUEST FOR RECOVERY OF THE PROJECTS GOING INTO SERVICE IN 2025 AND BEYOND IN THE RES RIDER.

A. As described by witness Liberkowski, the Company proposes to recover all projects noted above going into service in 2025 and beyond through the RES Rider. We propose to recover the capital-related revenue requirements and property taxes, as well as incremental O&M expenses. We also propose to include all the PTCs associated with the rider projects in the RES Rider. Therefore, we have not included any PTCs for these projects in the 2025-2026 MYRP.

Q. HOW IS THE RES RIDER TREATED WITH RESPECT TO PTCS IN THE 2025-2026 MYRP?

A. The Company requests PTC treatment consistent with the previously approved process. Specifically, we request that:

1) A new baseline PTC will be set in this rate case. We have included PTC amounts shown in Table 7 above as the base amount in the 2025-2026

MYRP[13]. See Volume 4, Section III Rate Base (Plant), Subpart P8-1, Production Tax Credits. These PTCs are generated from the Pleasant Valley, Borders, Courtenay, Blazing Star I, Foxtail, Lake Benton, Blazing Star II, Crowned Ridge, Jeffers, Community Wind North, Mower, Freeborn, Dakota Range, Northern Wind, Nobles Re-Power Wind, and Grand Meadow Re-Power wind facilities, which are included in the 2025-2026 MYRP.

2) The difference between actual and baseline PTCs be recorded in the RES Tracker account.
3) The difference will be either refunded to, or recovered from, customers as established in future RES Rider filings.

Because we propose that the true-up between the level of PTCs included in base rates through this MYRP and the actual amount of PTCs earned in the respective period would occur through the RES Rider, we do not anticipate a need to address this issue in the base rate revenue requirement in the final compliance filing.

Q. WHAT ADJUSTMENT HAVE YOU MADE TO ENSURE NO DOUBLE RECOVERY OF COSTS RECOVERED IN THE RES RIDER AFTER THE IMPLEMENTATION OF FINAL RATES IN THIS CASE?

A. The project costs and revenues remaining in the RES Rider have been removed from our 2025-2026 MYRP. A review is also done for each RES Rider filing to ensure that no costs included in base rates are included in the RES Rider filing. I provide information related to the 2025-2026 MYRP adjustment that ensures

[13] Baseline amounts is subject to update based on the rebuttal adjustment described in Section VII.F of my testimony.

no double recovery of these costs in Section VII.D. Rider Removals, RES Rider (adjustment 18).

b. RES Rider Roll-in

Q. PLEASE DESCRIBE HOW YOU ARE PROPOSING TO MOVE PROJECTS TO BASE RATES AT THE CONCLUSION OF THIS RATE CASE.

A. As noted above, we propose to move projects from the RES rider to base rates at the conclusion of this case because it reduces the interim rate increase and clarifies that there is no potential for double recovery of costs. Coincident with the implementation of final rates in this rate case, the project costs will be removed from the RES Rider for the remaining months of the year and final rates will be designed to recover the costs of these projects.

More specifically, the RES rider will be updated to exclude costs for these projects for the remaining months of the year following implementation. Final rates will be designed to recover the final revenue requirement approved by the Commission, including the final revenue requirement for these projects. The interim rate refund will not be affected for these projects, as any over/under recovery during the interim rate period related to these projects will remain in the RES Rider.

Q. WHAT DOES THE COMPANY PROPOSE TO INCLUDE IN ITS FINAL RATE COMPLIANCE TO SUPPORT MOVEMENT OF THESE PROJECTS FROM THE RES RIDER TO BASE RATES?

A. We propose to submit a RES Rider compliance report with final rate compliance reporting. This report will clearly identify the revenue requirements removed from the RES Rider, the revenue recovered from customers for the projects moving to base rates during the interim rate period, and the development of the revised RES Rider adjustment factor. The Company anticipates this process will be similar to the process used to move recovery of CIP costs from the CIP Rider to base rates.

Q. HOW ARE THE PROJECTS THAT WILL MOVE TO BASE RATES TREATED DURING THE INTERIM RATE PERIOD?

A. During the interim rate period, the Company proposes that the identified projects continue recovery through the RES Rider, along with the other costs that we are proposing to continue to recover through the RES Riders after implementation of final rates.

Q. HOW WILL YOU ENSURE NO DOUBLE RECOVERY OF THESE PROJECT COSTS OCCURS DURING THE INTERIM RATE PERIOD?

A. We are proposing to continue recovery of these projects through the RES Rider during the interim period and to move these projects into base rates at the end of this case. The MYRP also includes the project costs in the MYRP cost of service as well as the project revenues in present revenue. Thus, an interim rate adjustment is necessary to ensure no double recovery of these costs during the interim rate period. Accordingly, our 2025 and 2026 interim rate requests each include an adjustment to remove the projects identified to roll into base rates and the present revenue from the development of interim rates.

Q. PLEASE PROVIDE ADDITIONAL DETAIL RELATED TO THE INTERIM RATE ADJUSTMENT FOR THE RES RIDER COSTS.

A. The Interim Rate Adjustment removes the project costs and present revenue included in the 2025 test year and 2026 plan year from the Interim Cost of

Service. This adjustment decreases the Interim Cost of Service rate base and present revenue by the amounts shown in Table 13 below.

Table 13
Rider Removal from Interim Rates ($ in millions)

	Decrease in Rate Base		Decrease in Present Revenue	
	2025	**2026**	**2025**	**2026**
RES Rider	$297.6	$269.6	$14.2	$12.0

Additional detail on this adjustment can be found in Volume 1, Notice of Change in Rates and Interim Rate Petition.

Q. DO YOU PROVIDE ANY OTHER INFORMATION RELATED TO TREATMENT OF RES RIDER COSTS AND PROJECTS DURING THE MULTI-YEAR RATE PLAN PERIOD?

A. Yes. Exhibit___(BCH-1), Schedule 16, Rider Roll-in Timeline, provides a timeline illustrating how projects will be rolled into base rates or will remain in the TCR and RES Riders during the course of the MYRP.

2. TCR Rider

Q. WHAT IS THE TCR RIDER?

A. The TCR Rider is authorized by Minn. Stat. § 216B.16, subd. 7b to allow the recovery of Minnesota jurisdictional costs related to transmission and grid modernization investments and for MISO charges incurred for projects for which MISO assigns regional costs under Schedule 26 and Schedule 26A of its Tariff.

Q. WHAT COSTS ARE CURRENTLY INCLUDED IN THE TCR RIDER?

A. The Commission approved our provisional TCR Rider rate reduction reflecting the roll in of projects as proposed in the last rate case and request to recover the following projects in the TCR Rider in Docket No. E002/M-23-467:

- ADMS;
- AMI;
- FAN;
- LoadSeer;
- TOU Pilot;
- Hosting Capacity;
- MISO RECB Schedule 26 and 26A net revenue.

At the time this testimony is being prepared for filing, Docket No. E002/M-23-467 is pending before the Commission.

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE TCR RIDER DURING THE MULTI-YEAR RATE PLAN?

A. As described earlier, we propose to:

- Continue recovery of the ADMS, AMI, FAN, LoadSeer, TOU Pilot and Hosting Capacity projects in the TCR Rider;
- Seek recovery of the Bayfront to Ironwood and Brookings Second Circuit projects and Participant Compensation to be proposed in the TCR Rider;
- Continue recovery of MISO RECB Schedule 26 and 26A net revenue in the TCR Rider.

Q. PLEASE DESCRIBE THE PROJECTS THAT WILL REMAIN IN THE TCR RIDER AFTER THE IMPLEMENTATION OF FINAL RATES.

A. The Company is requesting continued recovery of the ADMS, AMI, FAN, TOU Pilot, LoadSeer, and Hosting Capacity and to begin recovery of the Bayfront to Ironwood and Brookings Second Circuit projects and Participant Compensation costs to be proposed in the TCR Rider. We propose to recover these projects through the TCR Rider because these are large qualifying projects that are not yet fully in-service. We are also requesting to continue recovery of the MISO RECB Schedule 26 and 26A net revenues through the TCR Rider.

Q. WHAT ADJUSTMENT HAVE YOU MADE TO ENSURE NO DOUBLE RECOVERY OF PROJECTS CONTINUING RECOVERY IN THE TCR RIDER AFTER THE IMPLEMENTATION OF FINAL RATES IN THIS CASE?

A. The project costs and revenues remaining in the TCR Rider have been removed from our 2025-2026 MYRP. A review is also done for each TCR filing to ensure that no costs included in base rates are included in the TCR filing. I provide information related to the 2025-2026 MYRP adjustment that ensures no double recovery of these costs in Section VII.D. Rider Removals, TCR Rider.

Q. HOW ARE YOU DEALING WITH PROJECTS NOT YET CERTIFIED?

A. The following projects are pending a final Commission order; therefore, for administrative ease and clarity we have removed any project costs or revenues from the 2025-2026 MYRP. The Company intends to request recovery for these projects in a future TCR Rider filing:

- MISO LRTP2 Alexandria to Big Oaks
- MISO LRTP4 Wilmarth to North Rochester to Tremval
- MISO LRTP5 Tremval to Eau Claire to Jump River

- MISO LRTP6 Tremval to Rocky Run to Columbia
- Minnesota Energy Connect

3. Fuel Clause Adjustment

Q. WHAT COSTS ARE RECOVERED THROUGH THE FCA?

A. Fuel and purchased energy are recovered from customers through the FCA.

Q. HOW IS THE FCA TREATED IN THE MYRP FORECAST?

A. Both revenue and fuel expenses recovered through the FCA are included in the MYRP Forecast, and the total amount of each is equal. Any true-up of the revenues and costs during the MYRP Forecast will occur in the FCA and, therefore, there will be no need to address a change in revenue requirement in the final compliance filing. I provide a reconciliation of fuel costs and revenues in the cost of service in Schedule 15, Fuel Reconciliation. As required by the Commission in its November 5, 2019 Order Approving Compliance Filings in Docket No. E999/CI-03-802, this schedule illustrates that fuel revenues are equal to fuel costs to be recovered through the FCA and thus the Company's proposed base rates do not include any amount of FCA costs.

4. Other Riders

a. RDF Rider

Q. WHAT COSTS ARE RECOVERED THROUGH THE RDF RIDER?

A. Commission-approved RDF costs pursuant to Minn. Stat. §§ 116C.779 and 216B.1645, subd. 2 are recovered from retail customers through the RDF Rider.

Q. HOW IS THE RDF RIDER TREATED IN THE MYRP FORECAST?

A. Both revenue and amortization expense for the RDF Rider are included in the MYRP Forecast. The amount of each is equal and therefore does not contribute to the MYRP Forecast deficiency. Any true-up of the revenues and costs will occur in the RDF Rider, such that there will be no need to address a change in revenue requirement in the final compliance filing.

b. CIP Rider

Q. WHAT COSTS ARE RECOVERED THROUGH THE CIP RIDER?

A. The CIP Rider is designed to recover conservation and demand-side management program costs that are incremental to the level collected in base rates. Base electric rates are designed to include conservation and demand-side management cost at an authorized level approved by the Deputy Commissioner of the Minnesota Department of Commerce, Division of Energy Resources for a given test year. The CIP Rider collects any incremental conservation and demand-side management costs above the authorized level in final base rates.

The CIP performance incentive is also recovered through the CIP Rider and is designed to compensate the Company for lost sales due to Company conservation efforts. The annual projected CIP performance incentive margin is included in the Other Revenue budget. The CIP performance margin is intended as an incentive to the Company and represents the budgeted level in anticipation of achieving the CIP goals. An adjustment is made to remove the estimated performance margin from the MYRP Forecast. Failure to include this adjustment would flow the annual CIP performance incentive to customers by overstating operating revenues in the MYRP Forecast and, therefore, understating the revenue deficiency for the MYRP.

Q. HOW IS THE CIP RIDER TREATED IN THE MYRP FORECAST?

A. As discussed in Section VII, Annual Adjustments to the MYRP, the CIP Rider amount in the case is at the level needed to assure that the CIP revenue (Base and Rider) is equal to the expense in the MYRP Forecast. With the total amount of CIP expense and CIP revenue equal, the overall CIP program does not contribute to the MYRP deficiency.

c. SEP Rider

Q. WHAT COSTS ARE RECOVERED THROUGH THE SEP RIDER?

A. Commission-approved SEP costs pursuant to Minn. Stat. § 216B.1645, Subd. 4 are recovered from retail customers through the SEP Rider.

Q. HOW IS THE SEP RIDER TREATED IN THE MYRP FORECAST?

A. Both the revenue and expense for the SEP Rider are included in the MYRP Forecast. The amount of each is equal and therefore, does not contribute to the MYRP Forecast deficiency. The Company is proposing to move remaining costs from the SEP Rider to base rates in this rate case.

d. Renewable*Connect Rider

Q. WHAT COSTS ARE RECOVERED THROUGH THE RENEWABLE*CONNECT RIDER?

A. Costs related to the Renewable*Connect program, a stand-alone retail service program with discrete revenues, purchase power contracts, and operating expenses, are recovered through the Renewable*Connect Rider.

Q. HOW IS THE RENEWABLE*CONNECT RIDER TREATED IN THE MYRP FORECAST?

A. All revenue and expense related to the Renewable*Connect program are excluded from the MYRP Forecast. The Renewable*Connect Rider removal adjustment shown in column 27 of Schedules 11a-11b, 2025-2026 Income Statement Adjustment Schedules reflects the removal of the Renewable*Connect-related expenses and revenue included in base data and does not impact the deficiency. Any true-up of the revenues and costs incurred during the MYRP Forecast will occur in the Renewable*Connect Rider, such that there will be no need to address a change in revenue requirement in the final compliance filing. Further information is provided in Section VII, Annual Adjustments to the MYRP.

B. Trackers and Deferrals

Q. WHAT TOPICS DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I discuss the trackers and deferrals the Company is proposing in this proceeding. Specifically, the Company has carried some deferrals and trackers for several rate cases that address highly variable costs and are either neutral (*i.e.,* protect both customers and the Company from cost increases or decreases from test year proposals) or offer one-way customer protections (*i.e.,* caps or other features that protect customers against significant increases in cost or decreases in revenue without symmetrical features for the Company). Several past deferrals and trackers have helped the Company withdraw rate cases it otherwise would have needed to pursue while also protecting customers, including the sales true-up, capital true-up, and property tax tracker. Other trackers, such as the capacity revenue tracker and PTCs tracker to which the Company and Department have agreed in the past and which were approved in the Company's last rate case, help manage the volatility of certain types of revenues, costs, and credits (e.g., unusually high capacity revenues) without any party or the Commission having to guess what future conditions might require.

Q. DO ANY OF THE TRACKERS OR DEFERRALS PROVIDE "UPSIDE" TO THE COMPANY AS COMPARED TO CUSTOMERS WITH RESPECT TO RECOVERY OF COSTS OR REVENUES?

A. No. Each of the trackers and deferrals we propose to continue or add are either neutral or offer one-way customer protections. For example, our capital true-up is a one-way mechanism that requires customer refunds when actual capital-related revenue requirements are less than the capital-related revenue requirement amounts approved in the applicable year of the MYRP. Our other mechanisms support symmetrical tracking of costs, so customers only pay actual costs incurred, are credited all applicable revenues, and the Company does not over- or under-recover actual costs or revenues.

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO TRACKERS AND DEFERRALS?

A. For the reasons discussed above and in other Company testimony, I recommend continuing the sales true-up, capital true-up, wind and solar PTCs, and property tax true-ups that were approved in prior Company rate cases and related filings. Company witness Liberkowski addresses the Company's sales, capital, and property tax tracker proposals in Direct Testimony.

To manage through other highly variable circumstances facing the Company and our customers, I propose new tracker treatment for Nitrogen Oxide (NOx) allowances, Coal Combustion Residuals (CCR), and bad debt expense. I also provide detailed information supporting the deferral or tracker-related adjustments to the MYRP that I presented in Section VII of my testimony. The proposed treatment for each of these new trackers is set forth in the next subsections of my testimony.

1. NOx Allowances

Q. WHAT IS THE COMPANY PROPOSING WITH RESPECT TO NOX ALLOWANCES?

A. Company witness Jeffrey L. West discusses the potential operational and financial impacts to the Company and its generating assets from the United States Environmental Protection Agency's (EPA) "Good Neighbor Plan" (GNP)[14] and the Company's proposal to establish a tracker for costs incurred to comply with the rule. The GNP seeks to limit ozone-forming emissions of NOx from power plants by establishing a NOx allowance budget for fossil fuel-fired power plants in the subject states and allowing for buying and selling NOx allowances between entities. However, there are two court cases that have affected implementation of the rule, and it is not yet known whether the rule will be enforced in Minnesota. The inclusion of Minnesota generating units in the program will impact the Company because we will likely need to purchase allowances beyond those allocated to our generating units under the GNP to engage in typical levels of operation of our plants. Because the amount of allowances needed cannot currently be predicted, the Company requests that the Commission allow the Company to defer any costs incurred for NOx allowance purchases to comply with the GNP.

[14] Federal Implementation Plan for the 2015 8-hour Ozone National Ambient Air Quality Standards, Docket ID No. EPA-HQ-OAR-2021-0668.

Q. WHY DOES THE COMPANY BELIEVE A TRACKER WOULD BE APPROPRIATE?

A. As discussed above, given the ongoing legal proceedings that have affected implementation of GNP for Minnesota, it is not yet known when or if the Company will need to expend funds to comply with the GNP. As discussed in witness West's testimony, if the GNP is implemented for Minnesota, costs associated with compliance could be in the range of $18 million to $40.5 million per year, and cannot be accurately predicted at this time because pricing for NOx allowances may be affected by implementation of the GNP rule in Minnesota. For these reasons, establishing a tracker is appropriate to address the uncertainty associated with this potential regulatory requirement.

Q. PLEASE DESCRIBE THE COMPANY'S TRACKER PROPOSAL IN MORE DETAIL.

A. We propose to defer any costs associated with NOx allowance purchases to comply with the GNP for recovery in our next Minnesota electric rate case and would submit an annual compliance filing tracking actual costs incurred and addressing a plan for any recovery. I provide additional details at the end of this section about how deferred refunds or recoveries for the various trackers proposed by the Company will be netted together.

Q. WHY IS THIS TRACKER PROPOSAL REASONABLE?

A. Given the uncertainty around implementation and timing of the GNP for Minnesota, a tracker is an appropriate mechanism for recovery of these potential costs. A tracker mechanism allows the Company to recover the costs associated with regulatory compliance requirements related to the provision of service to our customers and ensures that only actual costs are recovered from customers.

2. *Coal Combustion Residuals (CCRs)*

Q. WHAT IS THE COMPANY PROPOSING WITH RESPECT TO CCRS?

A. Witnesses Johnson and West address EPA's recent amendment to 2015 regulations governing how coal ash, also known as CCRs, is managed, including management of CCRs at sites that have been previously closed or dormant. These changes will affect the manner in which the Company manages CCR sites and will increase costs associated with management of those sites. While the Company is working to identify any known CCR related remediations, the scope and impact of the amended regulations on future incremental costs has yet to be determined. CCR costs are normally included within overall decommissioning costs as part of the cost of removal component of net salvage for generating plants. As witness Johnson discusses, the Company proposes two potential recovery mechanisms (which are not mutually exclusive) for recovery of the yet to be determined costs associated with the new regulations: (1) recovery of CCR costs through depreciation expense, via cost of removal; and (2) a tracker mechanism which would defer costs and recover them over a future time period to be established either in this or a future rate case. The Company is proposing that the Commission approve deferred accounting treatment for investigative and remediation costs associated with all inactive or closed sites, with the ability for the Commission to approve the inclusion of other active sites in this deferral to the extent that there is not sufficient remaining life or cost of removal reserves to cover CCR associated costs. I discuss the proposed tracker mechanism below.

Q. WHY DOES THE COMPANY BELIEVE A TRACKER WOULD BE APPROPRIATE?

A. Establishing a tracker is appropriate to address the uncertainty associated with the actual costs that will be incurred under the revised EPA rules. The Company is actively working to assess the long-term remediation and monitoring impacts of the new regulation. Additionally, it has developed initial estimates and is refining those estimates as the scope and costs become clearer through both investigation and increased clarity around requirements for beneficial reuse of CCRs. For these reasons, establishing a tracker is appropriate to address the uncertainty associated with the level of costs that will be incurred under these new regulatory requirements.

Q. PLEASE DESCRIBE THE COMPANY'S TRACKER PROPOSAL IN MORE DETAIL.

A. We propose to defer costs associated with compliance of the new EPA regulations for recovery in our next Minnesota electric rate case and would submit an annual compliance filing. Our compliance filing will report actual costs incurred and will address a plan for any recovery. I provide additional details at the end of this section about how deferred refunds or recoveries for the various trackers proposed by the Company will be netted together.

Q. WHY IS THIS TRACKER PROPOSAL REASONABLE?

A. Given the uncertainty around the costs that will be necessary to comply with revised EPA rules and ongoing interpretation of those rules, a tracker is an appropriate mechanism for recovery of these costs. A tracker mechanism allows the Company to recover these costs associated with these regulatory compliance requirements related to the provision of service to our customers and ensures that only actual costs are recovered from customers.

3. Bad Debt

Q. WHAT IS THE COMPANY PROPOSING WITH RESPECT TO BAD DEBT?

A. Witness Lindgren discusses the bad debt expense levels in the 2025 and 2026 rate case budgets. As noted by witness Lindgren, in the Company's currently pending proceeding on its Annual Safety, Reliability, and Service Quality Report,[15] the Company reviewed the impact of a reduction to payment plan down payments amounts agreed upon by the Joint Commenters in that proceeding. The Company assessed the average of all payment arrangements set in 2022 and 2023 and the same data for 2024 through August, and the Company estimates up to a $1 million annual increase to bad debt due to the proposed reduction in payment plan down payments. With the down payment reduction pending approval, the impact has not been incorporated into the 2025-2026 budgets. Further, because we do not have a full year of data for 2024 and cannot predict additional arrangements customers may set, the impact could potentially be higher than estimated. As such, the Company requests approval to defer costs above or below the test year and plan year amounts in a tracker account for recovery or return to customers.

Q. WHY DOES THE COMPANY BELIEVE A TRACKER WOULD BE APPROPRIATE?

A. The reduction to payment plan downpayment amounts is pending approval, and the full impacts, which are expected to increase bad debt expense, are not yet known. Establishing a tracker is appropriate to address the uncertainty associated with implementation of reduced down payment amounts.

[15] *In the Matter of Xcel Energy's 2023 Annual Safety, Reliability, and Service Quality Report*, Docket No. E002.M-24-27, Xcel Energy Supplemental Reply Comments (September 23, 2024).

Q. PLEASE DESCRIBE THE COMPANY'S TRACKER PROPOSAL IN MORE DETAIL.

A. We propose to establish the baseline bad debt amount in our MYRP revenue requirement based on the current 2025 and 2026 budgeted amounts in this case and track actual annual costs above and/or below this baseline until our next electric rate case, and would submit an annual compliance filing. Our compliance filing will compare actual and MYRP amounts and will provide a refund plan for any over-recovery or a deferral for any under-recovery. I provide additional details at the end of this section about how deferred refunds or recoveries for the various trackers proposed by the Company will be netted together.

Q. WHY IS THIS TRACKER PROPOSAL REASONABLE?

A. Given the size of the potential impact to bad debt expense during the MYRP period, and because the Company cannot yet predict the level of impact of the change, a tracker is an appropriate mechanism for recovery of these costs. Setting a baseline amount for this expense in base rates allows the Company to recover these costs and ensures that only actual costs are recovered from customers.

Q. CAN YOU PROVIDE ADDITIONAL DETAILS ABOUT HOW DEFERRED REFUNDS OR RECOVERIES FOR THE VARIOUS TRACKERS PROPOSED BY THE COMPANY WILL BE NETTED TOGETHER?

A. Yes. While the Company proposes a few different trackers, ultimately, we anticipate that any deferred refunds or recoveries for the trackers will be netted together. The Company will combine the refunds or deferrals from all of the annual compliance filings for the tracker mechanisms discussed above and will issue a refund to customers for a net refund – or if a deferral remains, the remaining amount will be deferred and applied to any future year compliance refund until the next rate case. In this way, the reconciliation of actual costs to the baseline amounts in the MYRP will be straightforward and result in a single net number to be refunded to or collected from customers.

IX. COMPLIANCE WITH PRIOR COMMISSION ORDERS

Q. WHAT TOPIC DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. The Completeness Checklist included in the Direct Testimony of Company witness Liberkowski as Exhibit___(AAL-1), Schedule 2 documents how our rate case filing includes information required by Rule or prior Commission Orders and provides specific references to the testimony of Company witnesses that address each requirement. In this section of my testimony, I identify and provide information related to specific requirements from prior Commission Orders that have not been addressed elsewhere in my testimony.

A. General Rate Case – Docket No. E002/GR-12-961

1. Mapping to FERC Form 1

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REQUIREMENTS TO RECONCILE INFORMATION BETWEEN THE COMPANY'S FERC FORM 1 AND GENERAL LEDGER.

A. Order Point 47 from the Commission's September 3, 2013 order in Docket E002/GR-12-961 (the 12-961 Order) stated:

> In the initial filing of its next rate case, the Company shall expand upon the information filed under Minnesota Rules 7825.4000(B) and 7825.4100(B), including balance sheet and income statement reconciliations between its FERC Form 1 and its general ledger accounts, for each of the three most recent calendar years relative to the rate case test year. The schedules provided shall be produced in

like manner as requested and illustrated in the Department's Information Request 128-Revised, marked in the record as Exhibit 163, DOC Attachment ACB-15.

These requirements have been met. The mapping to FERC Form 1 is located in Volume 3, Required Information, Section IV, Other Required Information, Subpart 5, GAAP to FERC Mapping. There we provide accounting of the NSPM Total Company for 2021 through 2023. For each year, we provide the GAAP financial statements reconciled to the FERC Form 1. We then provide the FERC Form 1 reconciled to the Minnesota Jurisdictional Annual Report Total Company amounts.

2. *Changes Between Actuals and MYRP Forecast*

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REPORTING REQUIREMENTS RELATED TO DEVIATIONS BETWEEN MOST RECENT ACTUALS AND THE MYRP FORECAST.

A. Order Point 47 of the 12-961 Order also requires explanations for deviations ten percent or greater (+/- 10 percent) "between actuals and [the Company's] test-year request." Explanations of operating expense variations of +/-5 percent and +/-$500,000 are provided for 2023 actuals compared to the 2025 budget by FERC account in Volume 5, Budget Summary, Documentation, and Supplemental Budget Information. Explanations of variations of +/-10 percent on rate base items are provided with the schedules in Volume 3, Required Information, Section IV, Other Required Information, Subpart 5, GAAP to FERC Mapping.

3. Financial Labeling

Q. WHAT ARE THE REQUIREMENTS RELATED TO LABELING FINANCIAL INFORMATION?

A. In the Revenue Requirement Rebuttal Testimony in Docket E002/GR-12-961, the Company agreed to make efforts to label all costs and revenues to the relevant financial source: Xcel Energy Services, Inc.; NSP System; NSP-Minnesota or NSPM (Total Company – electric and gas utilities); NSPM Electric; and State of Minnesota Electric Jurisdiction.

Q. HOW HAS THE COMPANY COMPLIED WITH THIS COMMITMENT?

A. We have made a good faith effort to satisfy this commitment throughout all testimony in this case. For reference, following is a list of the labels used and the definitions of each.

- Xcel Energy, Xcel Energy, Inc., or XEI: The entire enterprise – XES, NSPM, NSPW, SPS, PSCo, and affiliate companies.
- XES: Xcel Energy Services: Xcel Energy's service company that provides services across all Xcel Energy affiliate companies.
- NSPM (Total Company): Northern States Power Company-Minnesota, providing service to electric and gas customers in Minnesota, North Dakota, and South Dakota.
- NSPW (Total Company): Northern States Power Company-Wisconsin, providing service to electric and gas customers in Wisconsin and Michigan.
- NSP System: The combined NSPM and NSPW electric production and transmission system.
- NSPM Electric: Northern States Power Company-Minnesota, including the portion allocated or direct assigned to the electric utility.

- State of Minnesota: Items physically located in the State of Minnesota such as distribution facilities or property taxes assessed by the State.
- State of Minnesota Electric Jurisdiction: Amounts direct assigned or allocated to the electric utility and to the State of Minnesota. Interchange Agreement billings to and from NSPW are reflected in revenues and expenses, respectively.
- State of Minnesota Electric Jurisdiction net of Interchange Agreement billings to NSPW or State of Minnesota Electric Jurisdiction, net of Interchange: The net amount allocated to the cost of service for electric customers in the State of Minnesota. The portion of the item billed to NSPW through the Interchange Agreement has been netted against the item to show the net impact to Minnesota electric customers.

Further, other Company witnesses provide amounts in their testimonies from several applicable financial sources. To the extent practicable, they have also provided the State of Minnesota jurisdictional amounts. The jurisdictional amounts were developed under my guidance and are consistent with development of allocators as explained in the CAAM presented in Company witness Doyle's Exhibit___(NLD-1), Schedule 3 to Direct Testimony, and in Schedule 3, COSS Summary, to my Direct Testimony. In order to provide further context, an index to these financial sources is included as Exhibit___(BCH-1), Schedule 5, Labeling of Financial Sources.

4. *Wholesale Customer Study*

Q. WHAT REQUIREMENT RELATED TO WHOLESALE CUSTOMERS DO YOU ADDRESS?

A. With respect to the costs and revenues related to services provided to wholesale customers, the Company and Department agreed as follows:

> The Company will provide as a compliance filing in future rate cases a wholesale customer study which shows all wholesale customers being served by the Company (including, but not limited to, full requirements, partial requirements, and market based wholesale customers), types of service being provided to each wholesale customer, costs and revenues associated with each wholesale customer, and a clear showing either that wholesale costs are allocated out of the retail rate case or that the revenues are included in the retail rate case, for all services provided to wholesale customers.[16]

Q. HOW HAS THE COMPANY COMPLIED WITH THIS REQUIREMENT?

A. Volume 3, Section IV. Other Required Information, Subpart 6, Wholesale Customer Study, provides the required information. The study does not address wholesale transmission revenues. Wholesale transmission revenues and associated costs are discussed in the Direct Testimony of Company witness Berklund.

B. Decommissioning

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REQUIREMENTS RELATED TO NUCLEAR DECOMMISSIONING.

A. A discussion of the Company's compliance history and the status of pending dockets with respect to nuclear decommissioning and the use of Department of Energy payments is contained in Section VIII, Triennial Nuclear Decommissioning Costs, of Company witness Johnson's Direct Testimony.

[16] May 22, 2013 Issues List Page 19 in Docket No. E002/GR-12-961.

C. Other Compliance Requirements

1. Incentive Compensation Refunds

Q. WHAT ARE THE REQUIREMENTS RELATED TO INCENTIVE COMPENSATION REFUNDS?

A. In Docket No. E002/GR-21-630, the Commission required Xcel Energy to continue to refund all incentive compensation payments recoverable in rates under the Order, but not paid.

Q. HOW IS COMPLIANCE WITH THESE REQUIREMENTS REFLECTED IN THE COMPANY'S RATE CASE REQUEST?

A. For 2023 (paid in March 2024), incentive plan payouts were at a level that required the Company to refund electric customers $1.7 million, as reported in our annual incentive compensation compliance filing in Docket Nos. E002/GR-21-630 and G002/21-678 on May 31, 2024.[17] Our 2022-2024 MYRP, which was based on a 2022 test year and 2023 and 2024 plan years, included the budgeted incentive compensation costs accrued in each test or plan year and payable in March of the subsequent year, after excluding certain costs (*e.g.*, executive long-term incentive).

The 2025 test year includes the budgeted incentive compensation costs accrued in 2025 and payable in March 2026, after excluding certain costs (*e.g.*, certain LTI, which I identified in Section VII, Annual Adjustments to the MYRP).

[17] The Company's annual incentive compensation compliance report for 2023 was also filed in its own separate proceeding, Docket No. E,G002/M-24-221, on June 11, 2024.

Q. DOES THE COMPANY PROPOSE ANY CHANGES TO THE AIP INCENTIVE REFUND PROGRAM?

A. Yes. The Company proposes to recover the target-level AIP amount, subject to a 20 percent cap (rather than the currently approved 15 percent cap), and to calculate the refund amount on an aggregate basis rather than by individual employee. This proposal is discussed in witness Ly's Direct Testimony.

2. *Nuclear Fuel Outage Costs*

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REPORTING REQUIREMENTS FOR NUCLEAR FUEL OUTAGE COSTS.

A. In Docket No. E002/GR-08-1065, the Company was directed to include an analysis of nuclear plant outage costs as shown in Exhibit 86 to the hearing record. The required information is included in Volume 4, Section III Rate Base (Plant), Subpart P4-1, Nuclear Outage Amortization. These schedules provide a determination of the Minnesota retail jurisdiction revenue requirements associated with the Nuclear Outage Deferral and Amortization method, as well as a comparison to the Direct Expense method for the MYRP Forecast.

3. *Capacity Cost Report*

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REQUIREMENTS RELATED TO CAPACITY COSTS.

A. In Docket No. E002/GR-08-1065, the Commission ordered the Company to describe NSP System short-term and long-term capacity costs by contract. The required information is provided in Volume 3, Section IV. Other Required Information, Subpart 7, Capacity Cost Study. The methodology for budgeting capacity costs for the 2025-2026 MYRP is similar to that described in the Direct Testimony of Company witness David G. Horneck in Docket No. E002/GR-

10-971. Contracts under which NSPM has long-term obligations to purchase capacity remain the same as described in that docket. The Company anticipates that it can meet the expected MISO capacity planning reserve requirements for the 2025 planning year from its current generation and long term purchased capacity contracts. Therefore, the Company does not expect to purchase short term capacity contracts for the 2025 test year.

4. North Dakota Investment Tax Credits

Q. WHAT ARE THE REQUIREMENTS RELATED TO THE NORTH DAKOTA INVESTMENT TAX CREDITS?

A. In Docket No. E002/M-15-805, the Company was instructed to share non-Minnesota state tax credits as follows:

> Northern States Power Company d/b/a Xcel Energy shall credit its Minnesota ratepayers for their proportionate share of used North Dakota Investment Tax Credits associated with the Courtenay Wind project, based on the pro-rata share of the costs of the Courtenay Wind project that is charged to Minnesota ratepayers.

Q. HOW HAS THE COMPANY COMPLIED WITH THESE REQUIREMENTS?

A. The North Dakota state credit for North Dakota-located wind generation is the only non-Minnesota state credit utilized by NSPM. Due to the size of the credits available relative to the North Dakota state taxable income, it is anticipated that the utilization of these credits will be limited by taxable income and not specifically known until North Dakota state tax returns are filed. Consistent with the order in the last rate case, North Dakota investment tax credits are included in the MYRP Forecast and support for the adjustment is included in Volume 4, Section III Rate Base (Plant), Subpart P8-2, Other Tax Credits.

5. *Capital True-Up*

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH CAPITAL TRUE-UP REPORTING REQUIREMENTS.

A. Continuing the capital true-up reporting from our 2022-2024 MYRP in accordance with the Commission's July 17, 2023 Order in Docket No. E002/GR-21-630, approving the Company's proposal in that case, the Company will submit an annual compliance filing in May 2025 for calendar year 2024. This compliance filing will compare the actual capital-related revenue requirements (actuals) to the capital forecast revenue requirements (forecast). The Company has also proposed to continue the capital true-up as a part of this case, as discussed by Company witness Liberkowski.

6. *FERC Transmission Audit Refunds*

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE RELATED TO THE FERC TRANSMISSION AUDIT REFUNDS.

A. In accordance with the Commission's Order dated December 10, 2021 on the Company's Transmission Cost Recovery Rider adjustment in Docket No. E002/M-19-721, I address how the FERC Transmission Audit refund impacts all components other than Schedule 26/26A. The FERC audit resulted in refunds to NSP Transmission Formula Rate customers. The refunds were included in the 2019 annual true up and were refunded as part of the 2021 transmission formula rate. This resolves the refund requirement.

7. *Recurring Compliance Reporting Requirements*

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION OF YOUR TESTIMONY?

A. Below, I provide information on compliance requirements of a recurring nature reported upon in each rate case.

a. Minnesota Emissions Allowance

Q. PLEASE DESCRIBE THE COMPANY'S USE OF APPROVED DEFERRED ACCOUNTING RELATED TO EMISSIONS ALLOWANCES.

A. In Docket No. E002/M-94-13, the Commission ordered deferred accounting for revenues from the sale of certain emission allowances until the Company's next general rate case, where the effects of then-new changes to the FERC Uniform System of Accounts could be examined. The Company has continued the deferral over several rate cases, but the accumulated unamortized deferred balance of emission sales is less than $5,000. Due to the small level in this account that has been accumulating since 2010 when the deferral was last resolved, combined with the limited market for these allowances, the Company is proposing to discontinue the deferral of emission allowances with no adjustment in this proceeding. Thus, there is no adjustment included in this filing.

b. Advantage Service (a/k/a HomeSmart)

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REQUIREMENTS RELATED TO HOME SMART.

A. In Docket No. E002/GR-91-1, the Company was directed to require NSP Advantage Service (now branded as Xcel Energy HomeSmart) to: 1) pay a return on the use of the Company's billing services asset; 2) compensate the Company for its personnel's referral time; and 3) compensate the Company for use of its mailing lists. The Company has complied with these requirements. However, due to the sale of HomeSmart in the fourth quarter of 2023, as noted in Company witness Doyle's Exhibit___(NLD-1), Schedule 9, this compliance requirement is no longer applicable as of that sale.

c. Liberty Paper

Q. WHAT ARE THE REQUIREMENTS RELATED TO LIBERTY PAPER?

A. In Docket No. E002/M-93-1253, the Commission ordered the Company to segregate the cost of constructing a steam pipeline from Sherco to Liberty Paper, Inc. from utility rate base, and to record operating and maintenance expenses to non-utility operations.

Q. HOW HAS THE COMPANY COMPLIED WITH THESE REQUIREMENTS?

A. When the Commission approved the amended agreement with Liberty Paper, Inc., in its February 21, 2020 Order in Docket No. E002/M-19-663, the Commission included a requirement that, for the duration of steam sales to Liberty Paper, Inc., the Company must demonstrate the reasonableness of the Company's proposed cost allocations related to the steam sales. The allocation of costs to Liberty Paper, Inc., and the reasonableness of those costs, are discussed in Section III of NSPM's CAAM, which is Schedule 3 to Company witness Doyle's Direct Testimony.

d. Tax Benefit Transfer Leases

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REQUIREMENTS RELATED TO TAX BENEFIT TRANSFER LEASES.

A. In Docket No. G002/GR-97-1606, the Company was directed to treat Tax Benefit Transfer (TBT) leases consistent with prior Commission approved methodology. There are no TBTs included in the MYRP. Since this provision has not been triggered in many years, the Company proposes to discontinue this reporting in future rate cases.

e. Sale of Renewable Energy Credits

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REQUIREMENTS RELATED TO THE SALE OF RECS.

A. In Docket No. E002/GR-08-1065, the Company was directed to flow revenues from the sale of RECs through the RES Rider. A petition to pass certain RECs to customers using the FCA was approved by the Commission in Docket No. E002/M-12-1132. The Commission ordered the proceeds from the sale of RECs be returned to customers through the RES Rider unless the Commission makes a specific determination to allow a sharing of the proceeds. The Company has complied with this requirement.

f. Competitive Bidding

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REQUIREMENTS FOR ANY NON-PERFORMANCE PENALTIES RELATED TO COMPETITIVELY BID GENERATION.

A. In Docket No. E002/M-95-174 the Company was permitted to offer Company-owned generation to compete against other provider offerings. The Company is required to track capacity-related non-performance penalties on NSP Generation projects for return to customers. We have incurred no such penalties. Since this provision has not been triggered in many years, the Company proposes to discontinue this reporting in future rate cases.

X. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. I recommend that the Commission determine an overall 2025 retail revenue requirement of $4.02 billion and 2025 revenue deficiency of $353.3 million for the Company's Minnesota jurisdictional electric operation, determined by the cost of service for the 2025 test year. I also recommend a revenue deficiency, including the 2025 request and the incremental 2026 request that together form the Company's overall revenue requests as follows:

Table 14
2025-2026 Incremental Revenue Requests
Minnesota Jurisdictional Deficiency Net of Interchange ($s in millions)

MYRP Year	2025	2026
Incremental Annual Deficiency ($)	$353.3	$137.5
Incremental Annual Deficiency (%) *	9.6%	3.6%

* The "Incremental Annual Deficiency (%)" is calculated using the annual revenue request over the forecasted present revenues in each applicable year, less prior year(s).

Lastly, I also recommend the Commission grant a 2025 interim rate increase of $223.8 million, and an additional 2026 interim rate increase of $138.8 million, for the Company's Minnesota jurisdictional operation.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Resume of Benjamin C. Halama

Director of Revenue Analysis
Revenue Requirements–North

Xcel Energy Services Inc.
401 Nicollet Mall
Minneapolis, MN 55401

<u>Current Responsibilities</u>

Since September 2018, I have worked as Manager or Director of the Revenue Requirements–North department. In this position, I prepare and present cost of service studies, revenue requirement determinations, and jurisdictional annual reports for the electric and gas operations of Northern States Power Company to the Minnesota Public Utilities Commission, the South Dakota Public Utilities Commission, and the North Dakota Public Service Commission, and the Federal Energy Regulatory Commission.

<u>Employment History</u>

Xcel Energy – Minneapolis, MN

- Director of Revenue Requirements–North, March 2024 to Present
- Manager of Revenue Requirements–North, September 2018 to March 2024
- Manager Utility Accounting, May 2015 to August 2018

Target Corporation – Minneapolis, MN

- Manager of Inventory Accounting, 2014-2015
- Lead Analyst Financial Reporting, 2013-2014
- Supervisor Sales Accounting and Operations, 2011-2013

Copeland Buhl and Company – Wayzata, MN

- Accounting Supervisor, 2007-2011
- Senior Accountant, 2004-2007
- Staff Accountant, 2002-2004

<u>Education</u>

University of Wisconsin at Eau Claire, May 2002
Bachelor of Science in Accounting

SUMMARY OF REVENUE REQUIREMENTS
($000's)

Line	Description	Adjusted Proposed Test Year 2025	Adjusted Proposed Plan Year 2026
1	Average Rate Base	$13,237,993	$14,033,262
2	Operating Income (Before AFUDC)	$667,511	$624,383
3	Allowance for Funds Used During Construction	$81,561	$85,437
4	Total Available for Return (Line 2 + Line 3 + Rounding)	$749,071	$709,819
5	Overall Rate of Return (Line 4 / Line 1)	5.66%	5.06%
6	Required Rate of Return	7.56%	7.55%
7	Operating Income Requirement (Line 1 x Line 6)	$1,000,792	$1,059,511
8	Income Deficiency (Line 7 - Line 4)	$251,721	$349,692
9	Gross Revenue Conversion Factor	1.40335	1.40335
10	Revenue Deficiency (Line 8 x Line 9)	$353,253	$490,740
11	Retail Related Revenue Under Present Rates	$3,666,148	$3,725,121
12	Percentage Increase Needed in Overall Revenue (Line 10 / Line 11)	9.64%	13.17%
13	Retail Related Revenue Under Present Rates EXCLUDING FUEL	$2,774,948	$2,833,921
14	Percentage Increase Needed Excluding Fuel (Line 10 / Line 13)	12.73%	17.32%

COST OF SERVICE SUMMARY for 2025-2026 MYRP FORECAST ($000's)

Line No.		Minnesota Electric Jurisdiction 2025 Test Year	2026 Plan Year
1	**Composite Income Tax Rate**		
2	State Tax Rate	9.80%	9.80%
3	Federal Statuatory Tax Rate	21.00%	21.00%
4	Federal Effective Tax Rate	18.94%	18.94%
5	**Composite Tax Rate**	**28.74%**	**28.74%**
6	Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.403351	1.403351
7			
8	**Weighted Cost of Capital**		
9	Active Rates and Ratios Version	Proposed	Proposed
10	Cost of Short Term Debt	5.31%	3.38%
11	Cost of Long Term Debt	4.51%	4.53%
12	Cost of Common Equity	10.30%	10.30%
13	Ratio of Short Term Debt	0.79%	1.00%
14	Ratio of Long Term Debt	46.71%	46.50%
15	Ratio of Common Equity	52.50%	52.50%
16	Weighted Cost of STD	0.04%	0.03%
17	Weighted Cost of LTD	2.11%	2.11%
18	Weighted Cost of Debt	2.15%	2.14%
19	Weighted Cost of Equity	5.41%	5.41%
20	**Required Rate of Return**	**7.56%**	**7.55%**
21			
22	**Rate Base**		
23	Plant Investment	25,950,738	27,269,409
24	Depreciation Reserve	11,814,328	12,340,417
25	Net Utility Plant	14,136,410	14,928,992
26	CWIP	982,733	1,088,222
27			
28	Accumulated Deferred Taxes	2,939,658	2,977,595
29	DTA - NOL Average Balance	(0)	(0)
31	DTA - Federal Tax Credit Average Balance	(677,377)	(631,129)
32	Total Accum Deferred Taxes	2,262,282	2,346,466
33			
34	Cash Working Capital	(87,121)	(96,584)
35	Materials and Supplies	185,838	185,838
36	Fuel Inventory	85,634	85,634
37	Non-plant Assets and Liabilities	97,601	99,107
38	Customer Advances	(10,577)	(10,577)
39	Customer Deposits	(31,601)	(31,601)
40	Prepaids and Other	79,750	76,432
41	Regulatory Amortizations	61,607	54,266
42	Total Other Rate Base Items	381,131	362,514
43			
44	**Total Rate Base**	**13,237,993**	**14,033,262**
45			

COST OF SERVICE SUMMARY for 2025-2026 MYRP FORECAST ($000's)

Line No.		Minnesota Electric Jurisdiction	
		2025 Test Year	2026 Plan Year
46	**Operating Revenues**		
47	Retail	3,665,664	3,724,630
48	Interdepartmental	485	491
49	Other Operating Rev - Non-Retail	862,988	856,179
50	**Total Operating Revenues**	**4,529,136**	**4,581,300**
51			
52	**Expenses**		
53	Operating Expenses:		
54	Fuel	1,293,647	1,277,326
55	Deferred Fuel	5,114	4,840
56	Variable IA Production Fuel	10,544	10,614
57	Purchased Energy - Windsource	0	0
58	Fuel & Purchased Energy Total	1,309,305	1,292,781
59	Production - Fixed	442,822	449,195
60	Production - Fixed IA Investment		
61	Production - Fixed IA O&M	48,383	78,662
62	Production - Variable	3,350	2,473
63	Production - Variable IA O&M	6,283	6,379
64	Production - Purchased Demand	123,593	109,312
65	Production Total	624,431	646,021
66	Regional Markets	9,862	10,356
67	Transmission IA	139,233	143,891
68	Transmission	142,611	148,033
69	Distribution	116,658	135,135
70	Customer Accounting	68,408	76,805
71	Customer Service & Information	168,894	174,543
72	Sales, Econ Dvlp & Other	10,409	8,608
73	Administrative & General	290,503	299,667
74	**Total Operating Expenses**	**2,880,314**	**2,935,840**
75			
76	Depreciation	914,479	930,236
77	Amortization	44,939	54,152
78			
79	**Taxes:**		
80	Property Taxes	181,066	190,998
81	ITC Amortization	24,896	(1,508)
82	Deferred Taxes	35,879	37,875
83	Deferred Taxes - NOL		
84	Less State Tax Credits deferred		
85	Less Federal Tax Credits deferred	(228,552)	(227,036)
86	Deferred Income Tax & ITC	(167,776)	(190,669)
87	Payroll & Other Taxes	28,109	29,174
88	**Total Taxes Other Than Income**	**41,398**	**29,503**
89			

COST OF SERVICE SUMMARY for 2025-2026 MYRP FORECAST ($000's)

Line No.		Minnesota Electric Jurisdiction	
		2025 Test Year	2026 Plan Year
90	**Income Before Taxes**		
91	Total Operating Revenues	4,529,136	4,581,300
92	less: Total Operating Expenses	2,880,314	2,935,840
93	Book Depreciation	914,479	930,236
94	Amortization	44,939	54,152
95	Taxes Other than Income	41,398	29,503
96	**Total Before Tax Book Income**	648,006	631,570
97			
98	**Tax Additions**		
99	Book Depreciation	914,479	930,236
100	Deferred Income Taxes and ITC	(167,776)	(190,669)
101	Nuclear Fuel Burn (ex. D&D)	108,172	114,483
102	Nuclear Outage Accounting	53,341	46,357
103	Avoided Tax Interest	40,845	49,100
104	Other Book Additions	5,541	5,541
105	**Total Tax Additions**	954,602	955,048
106			
107	**Tax Deductions**		
108	Total Rate Base	13,237,993	14,033,262
109	Weighted Cost of Debt	2.15%	2.14%
110	Debt Interest Expense	284,617	300,312
111	Nuclear Outage Accounting	56,132	36,929
112	Tax Depreciation and Removals	1,263,145	1,320,216
113	NOL Utilized / (Generated)		
114	Other Tax / Book Timing Differences	(15,846)	(25,919)
115	**Total Tax Deductions**	**1,588,048**	**1,631,538**
116			
117	**State Taxes**		
118	State Taxable Income	14,560	(44,919)
119	State Income Tax Rate	9.80%	9.80%
120	State Taxes before Credits	1,427	(4,402)
121	Less State Tax Credits applied	(1,440)	(1,456)
122	**Total State Income Taxes**	(13)	(5,858)
123			
124	**Federal Taxes**		
125	Federal Sec 199 Production Deduction		
126	Federal Taxable Income	14,574	(39,061)
127	Federal Income Tax Rate	21.00%	21.00%
128	Federal Tax before Credits	3,060	(8,203)
129	Less Federal Tax Credits	(22,552)	21,248
130	**Total Federal Income Taxes**	(19,492)	13,045
131			
132	**Total Taxes**		
133	Total Taxes Other than Income	41,398	29,503
134	Total Federal and State Income Taxes	(19,505)	7,187
135	**Total Taxes**	21,893	36,690
136			
137	**Total Operating Revenues**	**4,529,136**	**4,581,300**
138	**Total Expenses**	**3,861,625**	**3,956,918**
139			
140	AFDC Debt	27,480	29,603
141	AFDC Equity	54,081	55,834
142			
143	**Net Income**	**749,071**	**709,819**

COST OF SERVICE SUMMARY for 2025-2026 MYRP FORECAST ($000's)

Line No.		Minnesota Electric Jurisdiction 2025 Test Year	2026 Plan Year
144			
145	**Rate of Return (ROR)**		
146	Total Operating Income	749,071	709,819
147	Total Rate Base	13,237,993	14,033,262
148	**ROR (Operating Income / Rate Base)**	5.66%	5.06%
149			
150	**Return on Equity (ROE)**		
151	Net Operating Income	749,071	709,819
152	Debt Interest (Rate Base * Weighted Cost of Debt)	(284,617)	(300,312)
153	Earnings Available for Common	464,455	409,508
154	Equity Rate Base (Rate Base * Equity Ratio)	6,949,946	7,367,463
155	**ROE (earnings for Common / Equity)**	6.68%	5.56%
156			
157	**Revenue Deficiency**		
158	Required Operating Income (Rate Base * Required Return)	1,000,792	1,059,511
159	Net Operating Income	749,071	709,819
160	**Operating Income Deficiency**	251,721	349,692
161			
162	Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.403351	1.403351
163	**Revenue Deficiency (Income Deficiency * Conversion Factor)**	**353,253**	**490,740**
164			
165	**Total Revenue Requirements**		
166	Total Retail Revenues	3,666,148	3,725,121
167	Revenue Deficiency	353,253	490,740
168	Total Revenue Requirements	4,019,401	4,215,862
169			
170	**Excluding Fuel Expense and Revenue**		
171	Total Fuel Related Expense and Revenue	1,037,511	1,033,426
172	Line 137 Less Fuel Related Revenue	3,491,625	3,547,875
173	Line 138 Less Fuel Related Expense	2,824,114	2,923,492
174	Revised Net Income (including AFUDC)	749,071	709,819
175	Change due to Excluding Fuel	-	-

Line No.	Summary Cash Working Capital		Lead/Lag Days	Minnesota Electric Jurisdiction 2025 Test Year Dollars	2025 Test Year Dollar x Days	2026 Plan Year Dollars	2026 Plan Year Dollar x Days
1	**Fuel Expenses**						
2	Coal and Rail Transport		16.94	138,679	2,349,231	138,679	2,349,231
3	Gas for Generation		38.81	220,821	8,570,079	220,821	8,570,079
4	Oil		11.15	-	-	-	-
5	Nuclear and EOL			106,348	-	106,420	-
6	**Subtotal Fuel Expenses**			**465,849**	**10,919,310**	**465,920**	**10,919,310**
7	**Purchased Power**						
8	Purchases		39.10	930,608	36,386,766	902,404	35,283,998
9	Interchange		37.04	172,804	6,400,955	178,701	6,619,380
10	**SubTotal Purchased Power**			**1,103,412**	**42,787,721**	**1,081,105**	**41,903,377**
11	**Labor and Related**						
12	Regular Payroll		12.05	389,473	4,693,148	392,849	4,733,825
13	Incentive		250.47	13,613	3,409,737	14,022	3,512,029
14	Pension and Benefits		37.04	71,757	2,657,985	74,258	2,750,641
15	**SubTotal Labor and Related**			**474,843**	**10,760,870**	**481,128**	**10,996,494**
16	All Other Operating Expenses		34.49	955,119	32,946,564	1,044,097	36,015,841
17	Property taxes		357.73	182,185	65,173,217	194,376	69,534,009
18	Employer's Payroll Taxes		23.84	28,109	670,116	29,174	695,502
19	Gross Earnings Tax		60.65	94,826	5,751,212	94,826	5,751,212
20	Federal Income Tax		36.25	(56,844)	(2,060,601)	(83,920)	(3,042,092)
21	State Income Tax		28.75	(13,543)	(389,371)	(29,361)	(844,134)
22	State Sales Tax Customer Billings		35.21	222,951	7,850,088	222,951	7,850,088
23	**Total Expenses**	A		**3,456,907**	**174,409,125**	**3,500,296**	**179,779,606**
24	Net Annual Expense			50.45	477,833	51.36	492,547
25	**Revenues**						
26	Retail Revenue		43.38	3,803,773	165,007,678	3,868,733	167,825,649
27	Late Payment		-	7,366		7,052	
28	Interdepartmental		-	485		491	
29	Misc Services		43.38	2,158	93,625	2,158	93,612
30	Rentals		(41.11)	4,748	(195,162)	4,786	(196,735)
31	Interchange		37.04	433,762	16,067,260	429,125	15,895,515
32	Sales for Resale		30.75	261,017	8,026,279	247,354	7,606,139
33	Retail Rev Lag Days		43.38	8,128	352,606	6,337	274,902
34	MISO		14.00	9,234	129,282	9,258	129,615
35	Wholesale Lag Days		30.75	245,156	7,538,535	257,694	7,924,090
36	**Total Revenues**	B		**4,775,827**	**197,020,102**	**4,832,988**	**199,552,786**
37	Net Annual Amount			41.25	539,781	41.29	546,720
38	Expense/Revenue Factor	C = A/B			72.383%		72.425%
39	Allocated Revenue Amount	D = B * C			390,712		395,962
40	**Net Cash Working Capital**	E = D - A			**(87,121)**		**(96,584)**

LABELING OF FINANCIAL SOURCES

Xcel Energy or XEI
The entire enterprise – XES, NSPM, NSPW, SPS, PSCo, and affiliate companies.

XES: Xcel Energy Services
Xcel Energy's service company that provides services across all Xcel Energy affiliate companies.

NSPM (Total Company)
Northern States Power Company-Minnesota providing service to electric and gas customers in Minnesota, North Dakota, and South Dakota.

NSPW (Total Company)
Northern States Power Company-Wisconsin providing service to electric and gas customers in Wisconsin and Michigan.

NSP System
The combined NSPM and NSPW electric production and transmission system.

NSPM Electric
Northern States Power Company, including the portion allocated or direct assigned to the electric utility.

State of Minnesota
Items physically located in the State of Minnesota, such as distribution facilities or property taxes assessed by the State.

State of Minnesota Electric Jurisdiction
Amounts direct assigned or allocated to the electric utility and to the State of Minnesota. Interchange Agreement billings to and from NSPW are reflected in revenues and expenses, respectively.

State of Minnesota Electric Jurisdiction net of Interchange Agreement billings to NSPW
Or, State of Minnesota Electric Jurisdiction, net of Interchange
The net amount allocated to the cost of service for electric customers in the State of Minnesota. The portion of the item billed to NSPW through the Interchange Agreement has been netted against the item to show the net impact to Minnesota electric customers.

Notes:

1. Jurisdictional numbers will be provided where practicable.
2. The table below shows the typical financial basis from which the allocations are being made, unless otherwise specified.

Order	**Topic**	**Witness**	**Financial Source**
1	Policy	Liberkowski	NSPM Electric
2	Revenue Requirements	Halama	State of MN Electric Jurisdiction
3	Capital Structure	Wehner	NSPM (Total Company)
4	ROE	Nowak	N/A
5	Budgeting and Employee Expense	Robinson	NSPM Electric / State of MN Electric Jurisdiction
6	Sales and Demand Forecast	Levine	NSPM Electric
7	Technology Services	Scheller	NSPM (Total Company)
8	Distribution	Mensen	NSPM Electric / State of MN Electric Jurisdiction
9	Customer Care/Bad Debt	Lindgren	NSPM Electric / State of MN Electric Jurisdiction
10	Nuclear Operations	Church	State of MN Electric Jurisdiction
11	Transmission	Berklund	State of MN Electric Jurisdiction
12	Energy Supply	Capra	State of MN Electric Jurisdiction
13	Wildfire	Sherwood	NSPM Electric / State of MN Electric Jurisdiction
14	Cost Allocations	Doyle	NSPM Electric
15	Property Tax	Kowalowski	NSPM (Total Company)
16	Insurance	Miller	XEI and NSPM (Total Company)
17	Pension and Benefits Expense	Schrubbe	State of MN Electric Jurisdiction
18	Ozone Seasonal Allowance	West	NSPM Electric
19	Compensation and Benefits	Ly	Xcel Energy, NSPM (Total Company), and NSPM Electric
20	Executive Compensation	Mustich	Xcel Energy, NSPM (Total Company), and NSPM Electric
21	Depreciation	Johnson	State of MN Electric Jurisdiction
22	Energy Justice	Martin	XEI and NSPM (Total Company)
23	CCOSS	Barthol	State of MN Electric Jurisdiction
24	Rate Design/Decoupling	Paluck	State of MN Electric Jurisdiction

DETAILED CASE DRIVERS
Test Year Drivers - Revenue Requirements - Incremental
Amounts in millions

	Increase (Decrease) 2025 TY to 2024 MYRP*	Increase (Decrease) 2026 TY to 2025 TY	**2-Year MYRP**
Capital Related			
Nuclear	$26.8	$5.9	$32.7
Steam	10.4	(30.2)	(19.9)
Wind	41.7	(6.0)	35.7
All Other Production	(11.3)	13.0	1.7
Transmission	16.6	19.5	36.1
Distribution	65.6	51.9	117.5
General and Intangible	30.7	16.8	47.5
DTA (Federal Credits & NOL)	(21.9)	(3.3)	(25.2)
Other Rate Base	13.0	(1.3)	11.7
Cost of Capital	102.2	6.1	108.3
TOTAL Capital Related	273.9	72.4	346.3
Amortizations	(4.1)	(0.3)	(4.4)
Taxes			
Taxes - Other	25.4	(3.8)	21.6
PTCs	(73.8)	45.3	(28.5)
Property Tax	(17.5)	9.9	(7.6)
Payroll Tax	(0.0)	1.1	1.0
TOTAL Taxes	(66.0)	52.5	(13.4)
Operating Expense			
Nuclear	17.8	(5.6)	12.2
Steam	(7.8)	17.0	9.1
Wind	18.6	(5.0)	13.5
Production Interchange	(1.4)	30.4	29.0
Purchased Demand	(24.7)	(14.3)	(39.0)
All Other Production	(2.1)	0.2	(1.9)
Transmission	(4.2)	4.4	0.2
Transmission Interchange	13.1	4.7	17.7
Distribution	4.6	18.9	23.5
Regional Markets	(0.2)	0.5	0.3
Customer Accounting / Info / Service	3.2	6.2	9.4
A&G	67.8	9.2	77.0
TOTAL O&M	84.6	66.4	151.0
Other Margin Impacts			
Sales Change	(31.6)	(45.6)	(77.3)
TCR and RES Revenue	(21.7)	1.8	(19.9)
Other Revenue	118.2	(9.7)	108.5
TOTAL Other Margin Impacts	64.9	(53.6)	11.3
TOTAL Net Incremental Deficiency	**$353.3**	**$137.5**	**$490.7**

*The 2024 plan year cost of service from the 2022-2024 MYRP.

COMPARISON OF DETAILED RATE BASE COMPONENTS
Test Year Ending December 31, 2025
($000's)

Line No.	Description	General Rate Case Filing Docket No. E002/GR-21-630 2024 Final Rates (A)	General Rate Case Filing Docket No. E002/GR-24-320 2025 Test Year (B)	Change (C) = (B) - (A)
	Electric Plant as Booked			
1	Production	$12,736,530	$13,503,928	$767,399
2	Transmission	4,064,693	4,258,347	193,654
3	Distribution	4,938,962	5,462,753	523,791
4	General	1,362,150	1,464,491	102,341
5	Common	1,213,087	1,261,218	48,131
6	TOTAL Utility Plant in Service	$24,315,421	$25,950,738	$1,635,316
	Reserve for Depreciation			
7	Production	$7,391,881	$7,707,909	$316,028
8	Transmission	945,528	995,930	50,402
9	Distribution	1,717,429	1,832,665	115,237
10	General	710,953	723,008	12,055
11	Common	626,623	554,815	(71,808)
12	TOTAL Reserve for Depreciation	$11,392,414	$11,814,328	$421,914
	Net Utility Plant in Service			
13	Production	$5,344,649	$5,796,020	$451,370
14	Transmission	$3,119,165	3,262,417	143,252
15	Distribution	$3,221,533	3,630,087	408,555
16	General	$651,197	741,483	90,286
17	Common	$586,464	706,403	119,939
18	Net Utility Plant in Service	$12,923,007	$14,136,410	$1,213,403
19	Utility Plant Held for Future Use	$0	$0	$0
20	Construction Work in Progress	$612,408	$982,733	$370,326
21	Less: Accumulated Deferred Income Taxes	$1,820,536	$2,262,282	$441,746
22	Cash Working Capital	($149,605)	($87,121)	$62,484
	Other Rate Base Items:			
23	Materials and Supplies	$154,701	$185,838	$31,137
24	Fuel Inventory	69,767	85,634	15,866
25	Non-Plant Assets & Liabilities	(13,840)	97,601	111,441
26	Customer Advances	(7,200)	(10,577)	(3,377)
27	Interest on Customer Deposits	(28,273)	(31,601)	(3,327)
28	Prepaids and Other	75,069	79,750	4,681
29	Regulatory Amortizations	$69,680	61,607	(8,073)
30	Total Other Rate Base Items	$319,904	$468,252	$148,348
31	Total Average Rate Base	$11,885,179	$13,237,993	$1,352,814

RATE BASE SCHEDULES

Detailed Rate Base Components
($000's)

Line No.	Description	2025 Test Year Adjusted (1)	2026 Plan Year Adjusted (1)
	Electric Plant as Booked		
1	Production	$13,503,928	$13,572,848
2	Transmission	4,258,347	4,515,407
3	Distribution	5,462,753	6,092,849
4	General	1,464,491	1,683,429
5	Common	1,261,218	1,404,876
6	TOTAL Utility Plant in Service	$25,950,738	$27,269,409
	Reserve for Depreciation		
7	Production	$7,707,909	$7,830,094
8	Transmission	995,930	1,063,192
9	Distribution	1,832,665	1,950,982
10	General	723,008	819,028
11	Common	554,815	677,122
12	TOTAL Reserve for Depreciation	$11,814,328	$12,340,417
	Net Utility Plant in Service		
13	Production	$5,796,020	$5,742,754
14	Transmission	3,262,417	3,452,216
15	Distribution	3,630,087	4,141,867
16	General	741,483	864,401
17	Common	706,403	727,754
18	Net Utility Plant in Service	$14,136,410	$14,928,992
19	Utility Plant Held for Future Use	$0	$0
20	Construction Work in Progress	$982,733	$1,088,222
21	Less: Accumulated Deferred Income Taxes	$2,262,282	$2,346,466
22	Cash Working Capital	($87,121)	($96,584)
	Other Rate Base Items:		
23	Materials and Supplies	$185,838	$185,838
24	Fuel Inventory	85,634	85,634
25	Non-Plant Assets & Liabilities	97,601	99,107
26	Customer Advances	(10,577)	(10,577)
27	Interest on Customer Deposits	(31,601)	(31,601)
28	Prepaids and Other	79,750	76,432
29	Regulatory Amortizations	61,607	54,266
30	Total Other Rate Base Items	$468,252	$459,099
31	Total Average Rate Base	$13,237,993	$14,033,262

(1) Revenues and expenses for riders have been included where applicable.

COMPARISON OF DETAILED INCOME STATEMENT COMPONENTS
Test Year Ending December 31, 2025
($000s)

Line No.	Description	General Rate Case Filing E002/GR-21-630 2024 Final Rates	General Rate Case Filing E002/GR-24-320 2025 Test Year	Change
		(A)	(B)	(C) = (B) - (A)
	Operating Revenues			
1	Retail	3,208,243	3,665,664	$457,421
3	Interdepartmental	386	485	99
4	Other Operating	718,576	862,988	144,412
5	Gross Earnings Tax	0	0	0
6	**Total Operating Revenues**	$3,927,205	$4,529,136	$601,932
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	$1,004,738	$1,309,305	$304,567
8	Power Production	634,761	634,293	(468)
9	Transmission	272,419	281,844	9,425
10	Distribution	128,391	116,658	(11,733)
11	Customer Accounting	51,861	68,408	16,547
12	Customer Service & Information	134,841	168,894	34,053
13	Sales, Econ Dvlp & Other	7,391	10,409	3,017
14	Administrative & General	222,713	290,503	67,790
15	Total Operating Expenses	$2,457,115	$2,880,314	$423,199
16	Depreciation	801,613	$914,479	$112,866
17	Amortizations	52,616	$44,939	(7,677)
	Taxes:			
18	Property	198,570	$181,066	($17,505)
19	Gross Earnings	0	0	0
20	Deferred Income Tax & ITC	(162,109)	(167,776)	(5,667)
21	Federal & State Income Tax	93	(19,505)	(19,598)
22	Payroll & Other	28,135	28,109	(26)
23	Total Taxes	$64,690	$21,893	($42,797)
24	**Total Expenses**	$3,376,034	$3,861,625	$485,592
25	AFUDC	$38,449	$81,561	$43,111
26	**Total Operating Income**	$589,621	$749,071	$159,451

Note: Revenues reflect calendar month sales.

COMPARISON OF DETAILED INCOME STATEMENT COMPONENTS
2025 Test Year and 2026 Plan Year
($000s)

Line No.	Description	2025 Test Year Adjusted (A)	2026 Plan Year Adjusted (B)
	Operating Revenues		
1	Retail	3,665,664	3,724,630
3	Interdepartmental	485	491
4	Other Operating	862,988	856,179
5	Gross Earnings Tax	0	0
6	**Total Operating Revenues**	$4,529,136	$4,581,300
	Expenses		
	Operating Expenses:		
7	Fuel & Purchased Energy	$1,309,305	$1,292,781
8	Power Production	634,293	656,378
9	Transmission	281,844	291,923
10	Distribution	116,658	135,135
11	Customer Accounting	68,408	76,805
12	Customer Service & Information	168,894	174,543
13	Sales, Econ Dvlp & Other	10,409	8,608
14	Administrative & General	290,503	299,667
15	Total Operating Expenses	$2,880,314	$2,935,840
16	Depreciation	914,479	930,236
17	Amortizations	44,939	54,152
	Taxes:		
18	Property	$181,066	$190,998
19	Gross Earnings	0	0
20	Deferred Income Tax & ITC	(167,776)	(190,669)
21	Federal & State Income Tax	(19,505)	7,187
22	Payroll & Other	28,109	29,174
23	Total Taxes	$21,893	$36,690
24	**Total Expenses**	$3,861,625	$3,956,918
25	AFUDC	$81,561	$85,437
26	**Total Operating Income**	$749,071	$709,819

Note: Revenues reflect calendar month sales.

RATE BASE SCHEDULES
Detailed Rate Base Components
($000's)

		Proposed Test Year 2025					
		Total Utility			Minnesota Jurisdiction		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Adjusted (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	Adjusted (F) (D) + (E)
	Electric Plant as Booked						
1	Production	$16,190,006	($535,158)	$15,654,848	$14,039,086	($535,158)	$13,503,928
2	Transmission	4,984,222	(74,913)	4,909,308	4,333,260	(74,913)	4,258,347
3	Distribution	6,534,080	(222,137)	6,311,942	5,684,890	(222,137)	5,462,753
4	General	1,810,228	(111,079)	1,699,150	1,575,569	(111,079)	1,464,491
5	Common	1,448,951	0	1,448,951	1,261,218	0	1,261,218
6	TOTAL Utility Plant in Service	$30,967,487	($943,287)	$30,024,200	$26,894,025	($943,287)	$25,950,738
	Reserve for Depreciation						
7	Production	$8,884,412	($13,104)	$8,871,308	$7,720,148	($12,239)	$7,707,909
8	Transmission	1,168,895	(689)	1,168,205	996,597	(667)	995,930
9	Distribution	2,094,144	(17,070)	2,077,074	1,849,736	(17,070)	1,832,665
10	General	859,016	(23,850)	835,166	747,331	(24,323)	723,008
11	Common	636,032	1,352	637,384	553,639	1,177	554,815
12	TOTAL Reserve for Depreciation	$13,642,499	($53,362)	$13,589,137	$11,867,449	($53,122)	$11,814,328
	Net Utility Plant in Service						
13	Production	$7,305,594	($522,054)	$6,783,540	$6,318,939	($522,919)	$5,796,020
14	Transmission	3,815,327	(74,224)	3,741,103	3,336,664	(74,246)	3,262,417
15	Distribution	4,439,935	(205,067)	4,234,869	3,835,154	(205,067)	3,630,087
16	General	951,212	(87,229)	863,984	828,239	(86,756)	741,483
17	Common	812,919	(1,352)	811,567	707,580	(1,177)	706,403
18	Net Utility Plant in Service	$17,324,987	($889,925)	$16,435,062	$15,026,575	($890,165)	$14,136,410
19	Utility Plant Held for Future Use	$0	$0	$0	$0	$0	$0
20	Construction Work in Progress	$1,497,379	($320,231)	$1,177,148	$1,302,964	($320,231)	$982,733
21	Less: Accumulated Deferred Income Taxe	$2,122,648	$463,191	$2,585,839	$1,865,689	$396,592	$2,262,282
22	Cash Working Capital	($109,646)	$11,453	($98,193)	($97,075)	$9,954	($87,121)
	Other Rate Base Items:						
23	Materials and Supplies	$213,612	$0	$213,612	$185,838	$0	$185,838
24	Fuel Inventory	98,888	0	98,888	85,634	0	85,634
25	Non-Plant Assets & Liabilities	111,411	0	111,411	97,601	0	97,601
26	Customer Advances	(14,112)	0	(14,112)	(10,577)	0	(10,577)
27	Interest on Customer Deposits	(31,686)	0	(31,686)	(31,601)	0	(31,601)
28	Prepaids and Other	91,751	0	91,751	79,750	0	79,750
29	Regulatory Amortizations	(14,842)	82,490	67,648	(12,910)	74,517	61,607
33	Total Other Rate Base Items	$455,023	$82,490	$537,513	$393,735	$74,517	$468,252
34	Total Average Rate Base	$17,045,095	($1,579,403)	$15,465,692	$14,760,510	($1,522,517)	$13,237,993

(1) Revenues and expenses for riders have been included where applicable. Capital structure represents level proposed in this rate case.

RATE BASE SCHEDULES

Detailed Rate Base Components
($000's)

Line No.	Description	Adjusted (1) Plan Year 2026 Total Utility (A)	Adjusted (1) Plan Year 2026 Minnesota Jurisdiction (B)
	Electric Plant as Booked		
1	Production	$15,804,353	$13,572,848
2	Transmission	5,208,829	4,515,407
3	Distribution	7,021,406	6,092,849
4	General	1,952,241	1,683,429
5	Common	1,613,997	1,404,876
6	TOTAL Utility Plant in Service	$31,600,826	$27,269,409
	Reserve for Depreciation		
7	Production	$9,015,941	$7,830,094
8	Transmission	1,245,952	1,063,192
9	Distribution	2,213,562	1,950,982
10	General	947,033	819,028
11	Common	777,895	677,122
12	TOTAL Reserve for Depreciation	$14,200,383	$12,340,417
	Net Utility Plant in Service		
13	Production	$6,788,412	$5,742,754
14	Transmission	3,962,877	3,452,216
15	Distribution	4,807,844	4,141,867
16	General	1,005,209	864,401
17	Common	836,102	727,754
18	Net Utility Plant in Service	$17,400,443	$14,928,992
19	Utility Plant Held for Future Use	$0	$0
20	Construction Work in Progress	$1,264,749	$1,088,222
21	Less: Accumulated Deferred Income Taxes	$2,695,817	$2,346,466
22	Cash Working Capital	($108,692)	($96,584)
	Other Rate Base Items:		
23	Materials and Supplies	$213,612	$185,838
24	Fuel Inventory	98,888	85,634
25	Non-Plant Assets & Liabilities	111,666	99,107
26	Customer Advances	(14,112)	(10,577)
27	Interest on Customer Deposits	(31,686)	(31,601)
28	Prepaids and Other	87,924	76,432
29	Regulatory Amortizations	58,055	54,266
30	Total Other Rate Base Items	$524,347	$459,099
31	Total Average Rate Base	$16,385,030	$14,033,262

(1) Revenues and expenses for riders have been included where applicable.

COMPARISON OF DETAILED RATE BASE COMPONENTS
Test Year Ending December 31, 2025
($000's)

		Proposed Test Year 2025					
		Total Utility			Minnesota Jurisdiction *		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Total (A) + (B)	Unadjusted (D)	Adjustments (E)	Total (D) + (E)
	Construction Work in Progress						
1	Production	$838,716	($304,001)	$534,715	$727,655	($304,001)	$423,654
2	Transmission	172,759	(11,777)	160,982	150,181	(11,777)	138,404
3	Distribution	122,450	0	122,450	108,735	0	108,735
4	General	268,509	(4,805)	263,704	233,763	(4,805)	228,958
5	Common	94,944	353	95,297	82,630	353	82,983
6	TOTAL Construction Work In Progre	$1,497,379	($320,231)	$1,177,148	$1,302,964	($320,231)	$982,733

		Plan Year 2026					
		Total Utility			Minnesota Jurisdiction *		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Total (A) + (B)	Unadjusted (D)	Adjustments (E)	Total (D) + (E)
	Construction Work in Progress						
7	Production	$721,425	($140,418)	$581,007	$626,635	($140,418)	$486,218
8	Transmission	180,631	(58)	180,573	157,225	(58)	157,167
9	Distribution	132,979	16	132,995	122,628	16	122,644
10	General	252,353	(827)	251,525	219,676	(827)	218,848
11	Common	118,101	548	118,649	102,797	548	103,345
12	TOTAL Construction Work In Progre	$1,405,488	($140,739)	$1,264,749	$1,228,961	($140,739)	$1,088,222

(*) See Volume 3, Rate Base Section, Schedule E for allocation factors.

COMPARISON OF DETAILED RATE BASE COMPONENTS
Test Year Ending December 31, 2025
($000's)

		Proposed Test Year 2025					
		Total Utility			Minnesota Jurisdiction *		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Total (A) + (B)	Unadjusted (D)	Adjustments (E)	Total (D) + (E)
	Accumulated Deferred Income Taxes						
1	Production	$1,618,368	($15,913)	$1,602,455	$1,401,572	($16,146)	$1,385,426
2	Transmission	896,270	(824)	895,446	787,376	(830)	786,545
3	Distribution	664,891	(8,666)	656,225	579,145	(8,666)	570,479
4	General	128,999	(7,374)	121,625	112,442	(7,226)	105,216
5	Common	79,682	(1,187)	78,495	69,323	(1,157)	68,166
6	Net Operating Loss (NOL)	(1,292,674)	497,155	(795,519)	(1,107,996)	430,619	(677,377)
7	Non-Plant Related	27,113	0	27,113	23,826	0	23,826
8	TOTAL Accum Deferred Income Tax	$2,122,648	$463,191	$2,585,839	$1,865,689	$396,592	$2,262,282

		Plan Year 2026					
		Total Utility			Minnesota Jurisdiction *		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Total (A) + (B)	Unadjusted (D)	Adjustments (E)	Total (D) + (E)
	Accumulated Deferred Income Taxes						
9	Production	$1,693,680	($67,540)	$1,626,140	$1,466,666	($68,504)	$1,398,162
10	Transmission	917,931	(2,331)	915,600	806,248	(2,351)	803,897
11	Distribution	674,955	(13,654)	661,301	586,768	(13,654)	573,114
12	General	137,536	(11,378)	126,159	119,874	(10,886)	108,988
13	Common	84,199	(2,998)	81,201	73,255	(2,928)	70,327
14	Net Operating Loss (NOL)	(1,549,998)	809,418	(740,580)	(1,332,476)	701,347	(631,129)
15	Non-Plant Related	25,996	0	25,996	23,107	0	23,107
16	TOTAL Accum Deferred Income Tax	$1,984,299	$711,518	$2,695,817	$1,743,441	$603,024	$2,346,466

(*) See Volume 3, Rate Base Section, Schedule E for allocation factors.

Rate Base Bridge Schedule - 2025 Test Year
($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
		Bridge - Unadjusted												Secondary Calculations			
Line No.		ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Unadjusted	Total Unadjusted	Depreciation Study: Remaining Life	Depreciation Study: TD&G	NOL ADIT ARAM	PI EPU Recovery	Sherco 3 Depr Deferral	Rider: RES	Rider: TCR	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Total
1							WP-A18	WP-A19	WP-A29	WP-A30	WP-A32	WP-A34	WP-A35	WP-A36	WP-A37	WP-A38	
2	Plant as booked																
3	Production				14,039,086	14,039,086						(535,158)					13,503,928
4	Transmission				4,333,260	4,333,260						(24,158)	(50,755)				4,258,347
5	Distribution				5,684,890	5,684,890						(234)	(221,903)				5,462,753
6	General				1,575,569	1,575,569						(257)	(110,822)				1,464,491
7	Common				1,261,218	1,261,218											1,261,218
8	Total Utility Plant in Service				26,894,025	26,894,025						(559,807)	(383,480)				25,950,738
9																	
10	Reserve for Depreciation																
11	Production				7,720,148	7,720,148	(5,854)					(6,384)					7,707,909
12	Transmission				996,597	996,597		(152)				182	(697)				995,930
13	Distribution				1,849,736	1,849,736		1,071				(5)	(18,136)				1,832,665
14	General				747,331	747,331	(38)	3,207				(29)	(27,463)				723,008
15	Common				553,639	553,639		1,177									554,815
16	Total Reserve for Depreciation				11,867,449	11,867,449	(5,892)	5,303				(6,236)	(46,296)				11,814,328
17																	
18	Net Utility Plant																
19	Production				6,318,939	6,318,939	5,854					(528,774)					5,796,020
20	Transmission				3,336,664	3,336,664		152				(24,341)	(50,058)				3,262,417
21	Distribution				3,835,154	3,835,154		(1,071)				(228)	(203,768)				3,630,087
22	General				828,239	828,239	38	(3,207)				(228)	(83,359)				741,483
23	Common				707,580	707,580		(1,177)									706,403
24	Net Utility Plant in Service				15,026,575	15,026,575	5,892	(5,303)				(553,570)	(337,184)				14,136,410
25																	
26	Utility Plant Held for Future Use																
27																	
28	Construction Work in Progress				1,302,964	1,302,964						(312,987)	(7,244)				982,733
29																	
30	Less: Accumulated Deferred Income Taxes	(3,482)		(735,552)	2,597,223	1,858,189	1,733	(1,597)		10,415	1,950	(32,127)	(16,514)	2,114		438,119	2,262,282
31																	
32	Other Rate Base Items																
33	Cash Working Capital		(96,797)			(96,797)									9,676		(87,121)
34	Materials and Supplies				185,838	185,838											185,838
35	Fuel Inventory				85,634	85,634											85,634
36	Non Plant Assets and Liabilities				97,601	97,601											97,601
37	Customer Advances				(10,577)	(10,577)											(10,577)
38	Customer Deposits				(31,601)	(31,601)											(31,601)
39	Prepayments				79,750	79,750											79,750
40	Regulatory Amortizations				(12,910)	(12,910)			33,387	25,476	4,780	10,874					61,607
41	Total Other Rate Base		(96,797)		393,735	296,938			33,387	25,476	4,780	10,874			9,676		381,131
42																	
43	Total Average Rate Base	3,482	(96,797)	735,552	14,126,051	14,768,288	4,159	(3,705)	33,387	15,061	2,829	(823,556)	(327,914)	(2,114)	9,676	(438,119)	13,237,993

Rate Base Bridge Schedule - 2026 Plan Year

($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
		Bridge - Unadjusted												Secondary Calculations			
Line No.		ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Unadjusted	Total Unadjusted	Depreciation Study: Remaining Life	Depreciation Study: TD&G	NOL ADIT ARAM	PI EPU Recovery	Sherco 3 Depr Deferral	Rider: RES	Rider: TCR	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Total
1							WP-A18	WP-A19	WP-A29	WP-A30	WP-A32	WP-A34	WP-A35	WP-A36	WP-A37	WP-A38	
2	Plant as booked																
3	Production				14,542,907	14,542,907						(970,059)					13,572,848
4	Transmission				4,616,518	4,616,518						(33,262)	(67,848)				4,515,407
5	Distribution				6,338,684	6,338,684						(235)	(245,600)				6,092,849
6	General				1,805,242	1,805,242						(258)	(121,556)				1,683,429
7	Common				1,404,876	1,404,876											1,404,876
8	Total Utility Plant in Service				28,708,227	28,708,227						(1,003,814)	(435,005)				27,269,409
9																	
10	Reserve for Depreciation																
11	Production				7,880,575	7,880,575	(22,750)					(27,731)					7,830,094
12	Transmission				1,065,930	1,065,930		(465)				(251)	(2,022)				1,063,192
13	Distribution				1,977,533	1,977,533		3,271				(13)	(29,809)				1,950,982
14	General				847,443	847,443	(113)	9,554				(72)	(37,785)				819,028
15	Common				673,476	673,476		3,647									677,122
16	Total Reserve for Depreciation				12,444,957	12,444,957	(22,864)	16,007				(28,067)	(69,615)				12,340,417
17																	
18	Net Utility Plant																
19	Production				6,662,331	6,662,331	22,750					(942,328)					5,742,754
20	Transmission				3,550,588	3,550,588		465				(33,011)	(65,826)				3,452,216
21	Distribution				4,361,151	4,361,151		(3,271)				(221)	(215,792)				4,141,867
22	General				957,799	957,799	113	(9,554)				(186)	(83,771)				864,401
23	Common				731,401	731,401		(3,647)									727,754
24	Net Utility Plant in Service				16,263,270	16,263,270	22,864	(16,007)				(975,746)	(365,389)				14,928,992
25																	
26	Utility Plant Held for Future Use																
27																	
28	Construction Work in Progress				1,228,961	1,228,961						(140,418)	(321)				1,088,222
29																	
30	Less: Accumulated Deferred Income Taxes	(4,135)		(1,357,148)	3,080,052	1,718,769	6,818	(4,817)		9,236	1,745	(89,191)	(24,765)	2,652		726,019	2,346,466
31																	
32	Other Rate Base Items																
33	Cash Working Capital		(106,518)			(106,518)									9,934		(96,584)
34	Materials and Supplies				185,838	185,838											185,838
35	Fuel Inventory				85,634	85,634											85,634
36	Non Plant Assets and Liabilities				99,107	99,107											99,107
37	Customer Advances				(10,577)	(10,577)											(10,577)
38	Customer Deposits				(31,601)	(31,601)											(31,601)
39	Prepayments				76,432	76,432											76,432
40	Regulatory Amortizations				(24,517)	(24,517)			31,233	22,592	4,277	20,682					54,266
41	Total Other Rate Base		(106,518)		380,315	273,797			31,233	22,592	4,277	20,682			9,934		362,514
42																	
43	Total Average Rate Base	4,135	(106,518)	1,357,148	14,792,494	16,047,259	16,046	(11,190)	31,233	13,356	2,532	(1,006,291)	(340,946)	(2,652)	9,934	(726,019)	14,033,262

SUMMARY OF REVENUE REQUIREMENTS - 2025 Test Year
($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
		Bridge - Unadjusted					Precedential	Adjustment										
Line No.		ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Unadjusted	Total Unadjusted	Precedential Adjustments	Bad Debt Expense	CIP Approved Program Levels	Depreciation Study: Remaining Life	Depreciation Study: TD&G	Dues: Chamber of Commerce	Excess Capacity Proceeds	Incentive Comp	LTI-Environmental	LTI-Time Based	Pension: Discount Rate	Pension: Retiree Medical
							WP A1-A15, excl A4	WP A16	WP A17	WP A18	WP A19	WP A4	WP A20	WP A21	WP A22	WP A23	WP A24	WP A25
1	Operating Revenues																	
2	Retail Revenue				3,784,780	3,784,780			18,993									
3	Interdepartmental				485	485												
4	Other Operating				1,015,049	1,015,049	5,582			(1,775)	(46)		2,128					
5	Total Revenue				4,800,313	4,800,313	5,582		18,993	(1,775)	(46)		2,128					
6																		
7	Expenses																	
8	Operating Expenses																	
9	Fuel & Purchased Energy				1,355,250	1,355,250												
10	Power Production				638,454	638,454	(4,663)											
11	Transmission				377,901	377,901												
12	Distribution				134,677	134,677												
13	Customer Accounting				68,429	68,429		1,754										
14	Customer Service and Information				150,151	150,151			18,993									
15	Sales, Econ Dev, & Other				10,249	10,249	160											
16	Administrative and General				304,170	304,170	(23,382)					222		(2,173)	3,024	8,458	117	66
17	Total Operating Expenses				3,039,280	3,039,280	(27,885)	1,754	18,993			222		(2,173)	3,024	8,458	117	66
18																		
19	Depreciation				948,112	948,112				(11,784)	10,605							
20	Amortization				37,758	37,758												
21																		
22	Taxes																	
23	Property				182,185	182,185												
24	Deferred Income Tax and ITC			(257,722)	121,298	(136,424)				3,466	(3,194)							
25	Federal and State Income Tax	(21)	581	253,303	(312,461)	(58,597)	9,630	(504)		(535)	9	(64)	612	624	(869)	(2,431)	(34)	(19)
26	Payroll and Other				28,148	28,148	(39)											
27	Total Taxes	(21)	581	(4,419)	19,171	15,313	9,591	(504)		2,931	(3,185)	(64)	612	624	(869)	(2,431)	(34)	(19)
28																		
29	Total Expenses	(21)	581	(4,419)	4,044,321	4,040,463	(18,294)	1,250	18,993	(8,854)	7,420	158	612	(1,548)	2,155	6,027	84	47
30																		
31	AFUDC				81,561	81,561												
32																		
33	Net Income	21	(581)	4,419	837,553	841,411	23,876	(1,250)		7,078	(7,466)	(158)	1,516	1,548	(2,155)	(6,027)	(84)	(47)
34																		
35	Calculation of Revenue Requirements																	
36	Rate Base	3,482	(96,797)	735,552	14,126,051	14,768,288				4,159	(3,705)							
37	Required Operating Income	242	(6,727)	51,121	981,761	1,026,396				289	(258)							
38	Operating Income	21	(581)	4,419	837,553	841,411	23,876	(1,250)		7,078	(7,466)	(158)	1,516	1,548	(2,155)	(6,027)	(84)	(47)
39	Income Deficiency	221	(6,146)	46,702	144,208	184,985	(23,876)	1,250		(6,789)	7,208	158	(1,516)	(1,548)	2,155	6,027	84	47
40	**Revenue Deficiency**	**310**	**(8,625)**	**65,540**	**202,374**	**259,600**	**(33,506)**	**1,754**		**(9,528)**	**10,115**	**222**	**(2,128)**	**(2,173)**	**3,024**	**8,458**	**117**	**66**

SUMMARY OF REVENUE REQUIREMEN

($000's)

(1)	(2)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)	(31)	(32)	(33)	(34)	(35)	(36)
				Amortization					Rider Removals			Secondary Calculations					Fuel Adjustment	
Line No.		PTC Transferability	Transmission ROE	Credit Card AutoPay	NOL ADIT ARAM	PI EPU Recovery	Rate Case Expenses	Sherco 3 Depr Deferral	Renewable Connect	Rider: RES	Rider: TCR	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss	Total	Remove FCA Revenue and Fuel Expense	Total Net of Fuel
		WP A26	WP A27	WP A28	WP A29	WP A30	WP A31	WP A32	WP A33	WP A34	WP A35	WP A36	WP A37	WP A39	WP A38			
1	Operating Revenues																	
2	Retail Revenue									(77,579)	(60,531)					3,665,664	891,200	2,774,464
3	Interdepartmental															485		485
4	Other Operating		(4,552)			1,140			(45,945)		(108,581)			(12)		862,988	146,311	716,677
5	Total Revenue		(4,552)			1,140			(45,945)	(77,579)	(169,112)			(12)		4,529,136	1,037,511	3,491,625
6																		
7	Expenses																	
8	Operating Expenses																	
9	Fuel & Purchased Energy								(45,945)							1,309,305	1,032,513	276,792
10	Power Production								5,336	(4,254)	(580)					634,293	-	634,293
11	Transmission		(0)								(96,056)					281,844	-	281,844
12	Distribution										(18,019)					116,658	-	116,658
13	Customer Accounting			(1,775)												68,408	-	68,408
14	Customer Service and Information								(250)							168,894	-	168,894
15	Sales, Econ Dev, & Other															10,409	-	10,409
16	Administrative and General															290,503	-	290,503
17	Total Operating Expenses		(0)	(1,775)					(40,859)	(4,254)	(114,655)					2,880,314	1,032,513	1,847,801
18																		
19	Depreciation									(10,078)	(22,376)					914,479	-	914,479
20	Amortization				2,154	2,884	1,640	503								44,939	4,998	39,941
21																		
22	Taxes																	
23	Property									(715)	(404)					181,066	-	181,066
24	Deferred Income Tax and ITC	12,199				(1,179)		(205)		(50,148)	(7,892)				15,600	(167,776)	-	(167,776)
25	Federal and State Income Tax		(1,308)	510	(201)	237	(471)	(17)	(1,462)	49,735	949	13	(58)	(2,286)	(12,968)	(19,505)	-	(19,505)
26	Payroll and Other															28,109	-	28,109
27	Total Taxes	12,199	(1,308)	510	(201)	(942)	(471)	(222)	(1,462)	(1,129)	(7,347)	13	(58)	(2,286)	2,632	21,893		
28																		
29	Total Expenses	12,199	(1,308)	(1,265)	1,953	1,942	1,169	281	(42,321)	(15,460)	(144,379)	13	(58)	(2,286)	2,632	3,861,625	1,037,511	2,824,114
30																		
31	AFUDC															81,561	-	81,561
32																		
33	Net Income	(12,199)	(3,243)	1,265	(1,953)	(802)	(1,169)	(281)	(3,624)	(62,119)	(24,734)	(13)	58	2,275	(2,632)	749,071	-	749,071
34																		
35	Calculation of Revenue Requirements																	
36	Rate Base				33,387	15,061		2,829		(823,556)	(327,914)	(2,114)	9,676		(438,119)	13,237,993	-	13,237,993
37	Required Operating Income				2,320	1,047		197		(57,237)	(22,790)	(147)	672	80,752	(30,449)	1,000,792	-	1,000,792
38	Operating Income	(12,199)	(3,243)	1,265	(1,953)	(802)	(1,169)	(281)	(3,624)	(62,119)	(24,734)	(13)	58	2,275	(2,632)	749,071	-	749,071
39	Income Deficiency	12,199	3,243	(1,265)	4,274	1,849	1,169	477	3,624	4,882	1,944	(134)	614	78,477	(27,817)	251,721	-	251,721
40	**Revenue Deficiency**	**17,120**	**4,552**	**(1,775)**	**5,998**	**2,595**	**1,640**	**670**	**5,086**	**6,851**	**2,728**	**(188)**	**862**	**110,131**	**(39,038)**	**353,253**	**-**	**353,253**

SUMMARY OF REVENUE REQUIREMENTS - 2026 Plan Year
($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
		Bridge - Unadjusted					Precedential	Adjustment										
Line No.		ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Unadjusted	Total Unadjusted	Precedential Adjustments	Bad Debt Expense	CIP Approved Program Levels	Depreciation Study: Remaining Life	Depreciation Study: TD&G	Dues: Chamber of Commerce	Excess Capacity Proceeds	Incentive Comp	LTI-Environmental	LTI-Time Based	Pension: Discount Rate	Pension: Retiree Medical
							WP A1-A15, excl A4	WP A16	WP A17	WP A18	WP A19	WP A4	WP A20	WP A21	WP A22	WP A23	WP A24	WP A25
1	Operating Revenues																	
2	Retail Revenue				3,878,695	3,878,695			(9,962)									
3	Interdepartmental				491	491												
4	Other Operating				1,012,571	1,012,571	4,371			(3,118)	(44)							
5	Total Revenue				4,891,757	4,891,757	4,371		(9,962)	(3,118)	(44)							
6																		
7	Expenses																	
8	Operating Expenses																	
9	Fuel & Purchased Energy				1,338,726	1,338,726												
10	Power Production				669,997	669,997	(2,935)											
11	Transmission				394,162	394,162												
12	Distribution				153,195	153,195												
13	Customer Accounting				75,973	75,973		2,608										
14	Customer Service and Information				184,755	184,755			(9,962)									
15	Sales, Econ Dev, & Other				8,443	8,443	165											
16	Administrative and General				314,016	314,016	(24,601)					222		(2,239)	3,278	8,812	118	61
17	Total Operating Expenses				3,139,266	3,139,266	(27,370)	2,608	(9,962)			222		(2,239)	3,278	8,812	118	61
18																		
19	Depreciation				999,688	999,688				(22,159)	10,803							
20	Amortization				46,971	46,971												
21																		
22	Taxes																	
23	Property				194,376	194,376												
24	Deferred Income Tax and ITC			(252,990)	106,848	(146,142)				6,704	(3,245)							
25	Federal and State Income Tax	(25)	640	244,837	(349,792)	(104,340)	9,135	(749)		(992)	55	(64)		644	(942)	(2,533)	(34)	(17)
26	Payroll and Other				29,214	29,214	(41)											
27	Total Taxes	(25)	640	(8,152)	(19,355)	(26,892)	9,094	(749)		5,711	(3,190)	(64)		644	(942)	(2,533)	(34)	(17)
28																		
29	Total Expenses	(25)	640	(8,152)	4,166,570	4,159,033	(18,276)	1,858	(9,962)	(16,448)	7,613	158		(1,596)	2,336	6,279	84	43
30																		
31	AFUDC				85,437	85,437												
32																		
33	Net Income	25	(640)	8,152	810,624	818,161	22,648	(1,858)		13,330	(7,657)	(158)		1,596	(2,336)	(6,279)	(84)	(43)
34																		
35	Calculation of Revenue Requirements																	
36	Rate Base	4,135	(106,518)	1,357,148	14,792,494	16,047,259				16,046	(11,190)							
37	Required Operating Income	287	(7,403)	94,322	1,028,078	1,115,285				1,115	(778)							
38	Operating Income	25	(640)	8,152	810,624	818,161	22,648	(1,858)		13,330	(7,657)	(158)		1,596	(2,336)	(6,279)	(84)	(43)
39	Income Deficiency	263	(6,763)	86,169	217,455	297,123	(22,648)	1,858		(12,215)	6,879	158		(1,596)	2,336	6,279	84	43
40	**Revenue Deficiency**	**368**	**(9,491)**	**120,926**	**305,165**	**416,968**	**(31,783)**	**2,608**		**(17,142)**	**9,654**	**222**		**(2,239)**	**3,278**	**8,812**	**118**	**61**

SUMMARY OF REVENUE REQUIREMENTS -
($000's)

(1)	(2)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)	(31)	(32)	(33)	(34)	(35)	(36)
				Amortization					Rider Removals			Secondary Calculations					Fuel Adjustment	
Line No.		PTC Transferability	Transmission ROE	Credit Card AutoPay	NOL ADIT ARAM	PI EPU Recovery	Rate Case Expenses	Sherco 3 Depr Deferral	Renewable Connect	Rider: RES	Rider: TCR	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss	Total	Remove FCA Revenue and Fuel Expense	Total Net of Fuel
		WP A26	WP A27	WP A28	WP A29	WP A30	WP A31	WP A32	WP A33	WP A34	WP A35	WP A36	WP A37	WP A39	WP A38			
1	Operating Revenues																	
2	Retail Revenue									(71,844)	(72,260)					3,724,630	891,200	2,833,430
3	Interdepartmental															491		491
4	Other Operating		(5,057)			1,011			(45,945)		(107,585)			(25)		856,179	142,225	713,954
5	Total Revenue		(5,057)			1,011			(45,945)	(71,844)	(179,844)			(25)		4,581,300	1,033,426	3,547,875
6																		
7	Expenses																	
8	Operating Expenses																	
9	Fuel & Purchased Energy								(45,945)							1,292,781	1,028,692	264,088
10	Power Production								5,429	(14,518)	(1,595)					656,378	-	656,378
11	Transmission		(1)								(102,239)					291,923	-	291,923
12	Distribution										(18,060)					135,135	-	135,135
13	Customer Accounting			(1,775)												76,805	-	76,805
14	Customer Service and Information								(250)							174,543	-	174,543
15	Sales, Econ Dev, & Other															8,608	-	8,608
16	Administrative and General															299,667	-	299,667
17	Total Operating Expenses		(1)	(1,775)					(40,766)	(14,518)	(121,894)					2,935,840	1,028,692	1,907,148
18																		
19	Depreciation									(33,838)	(24,258)					930,236	-	930,236
20	Amortization				2,154	2,884	1,640	503								54,152	4,734	49,418
21																		
22	Taxes																	
23	Property									(2,568)	(810)					190,998	-	190,998
24	Deferred Income Tax and ITC	13,307				(1,179)		(205)		(63,830)	(8,725)				12,646	(190,669)	-	(190,669)
25	Federal and State Income Tax		(1,453)	510	(188)	210	(471)	(15)	(1,489)	118,739	1,535	16	(60)	(2,024)	(8,285)	7,187	-	7,187
26	Payroll and Other															29,174	-	29,174
27	Total Taxes	13,307	(1,453)	510	(188)	(969)	(471)	(220)	(1,489)	52,342	(8,000)	16	(60)	(2,024)	4,361	36,690		
28																		
29	Total Expenses	13,307	(1,454)	(1,265)	1,966	1,915	1,169	283	(42,255)	3,987	(154,152)	16	(60)	(2,024)	4,361	3,956,918	1,033,426	2,923,492
30																		
31	AFUDC															85,437	-	85,437
32																		
33	Net Income	(13,307)	(3,603)	1,265	(1,966)	(905)	(1,169)	(283)	(3,691)	(75,830)	(25,692)	(16)	60	1,999	(4,361)	709,819	-	709,819
34																		
35	Calculation of Revenue Requirements																	
36	Rate Base				31,233	13,356		2,532		(1,006,291)	(340,946)	(2,652)	9,934		(726,019)	14,033,262	-	14,033,262
37	Required Operating Income				2,171	928		176		(69,937)	(23,696)	(184)	690	84,200	(50,458)	1,059,511	-	1,059,511
38	Operating Income	(13,307)	(3,603)	1,265	(1,966)	(905)	(1,169)	(283)	(3,691)	(75,830)	(25,692)	(16)	60	1,999	(4,361)	709,819	-	709,819
39	Income Deficiency	13,307	3,603	(1,265)	4,137	1,833	1,169	459	3,691	5,893	1,997	(168)	631	82,200	(46,097)	349,692	-	349,692
40	**Revenue Deficiency**	**18,675**	**5,057**	**(1,775)**	**5,806**	**2,572**	**1,640**	**644**	**5,179**	**8,270**	**2,802**	**(236)**	**885**	**115,356**	**(64,690)**	**490,740**	**-**	**490,740**

2025-2026 MYRP ADJUSTMENT SUMMARY

-1	(2)	(3)	(4)	(5)	(6)	(8)
				MN Electric		Workpaper
Line No.	Record Category	Report Label	Record Type	2025 Test Year	2026 Plan Year	Reference
1	Unadjusted	Unadjusted	**Total Unadjusted**	**352,117**	**489,439**	
2						
3	Precedential	Precedential Adjustments	NSPM-Advertising (Trad)	(3,210)	(3,120)	WP-A1
4	Precedential	Precedential Adjustments	NSPM-Assn Dues (Trad)	(375)	(358)	WP-A2
5	Precedential	Precedential Adjustments	NSPM-Aviation	(3,369)	(3,439)	WP-A3
6	Precedential	Precedential Adjustments	NSPM-Customer Deposits - A&G Expense (Trad)	37	37	WP-A5
7	Precedential	Precedential Adjustments	NSPM-Donations (Trad)	1,410	1,427	WP-A6
8	Precedential	Precedential Adjustments	NSPM-Econ Dev Donations (Trad)	160	165	WP-A7
9	Precedential	Precedential Adjustments	NSPM-Econ Develop (Trad)	(127)	(127)	WP-A8
10	Precedential	Precedential Adjustments	NSPM-Employee Expenses	(1,768)	(1,804)	WP-A9
11	Precedential	Precedential Adjustments	NSPM-Foundation Admin	(82)	(82)	WP-A10
12	Precedential	Precedential Adjustments	NSPM-Incentive Pay_Remove Long Term	(16,531)	(17,641)	WP-A11
13	Precedential	Precedential Adjustments	NSPM-Monticello EPU Commission Order No Return	(5,582)	(4,371)	WP-A12
14	Precedential	Precedential Adjustments	NSPM-Nuclear Retention Removal	(1,600)		WP-A13
15	Precedential	Precedential Adjustments	NSPM-Pension Non-Qualified Removal	(338)	(336)	WP-A14
16	Precedential	Precedential Adjustments	NSPM-Remove NonAsset Trading Fully Allocated Costs	(2,131)	(2,132)	WP-A15
17	Precedential		**Sub-Total Precedential**	**(33,506)**	**(31,783)**	
18						
19	Adjustment	Bad Debt Expense	NSPM-Bad Debt	1,754	2,608	WP-A16
20	Adjustment	CIP Approved Program Levels	NSPM-CIP Revenue and Expense Elimination	-	-	WP-A17
21	Adjustment	Depreciation Study: Remaining Life	NSPM-Remaining Life	(9,493)	(17,010)	WP-A18
22	Adjustment	Depreciation Study: TD&G	NSPM-MN Depreciation Study TD&G	10,085	9,562	WP-A19
23	Adjustment	Dues: Chamber of Commerce	NSPM-Chamber of Commerce Dues	222	222	WP-A4
24	Adjustment	Excess Capacity Proceeds	NSPM-Excess Capacity Proceeds	(2,128)		WP-A20
25	Adjustment	Incentive Comp	NSPM-Incentive Pay	(2,173)	(2,239)	WP-A21
26	Adjustment	LTI-Environmental	NSPM-Incentive Pay_Environmental LTI	3,024	3,278	WP-A22
27	Adjustment	LTI-Time Based	NSPM-Incentive Pay_Time Based LTI	8,458	8,812	WP-A23
28	Adjustment	Pension: Discount Rate	NSPM-Pension Discount Rate Int	117	118	WP-A24
29	Adjustment	Pension: Retiree Medical	NSPM-Pension Retiree Medical	66	61	WP-A25
30	Adjustment	PTC Transferability	NSPM-PTC Transferability Cost	17,120	18,675	WP-A26
31	Adjustment	Transmission ROE	NSPM-Transmission ROE Change	4,552	5,057	WP-A27
32	Adjustment		**Sub-Total Adjustment**	**31,604**	**29,142**	
33						
34	Amortization	Credit Card AutoPay	NSPM-Credit Card Auto Pay Fees	(1,775)	(1,775)	WP-A28
35	Amortization	NOL ADIT ARAM	NSPM-NOL Tax Reform ADIT ARAM	6,275	6,063	WP-A29
36	Amortization	PI EPU Recovery	NSPM-PI EPU Deferral	2,720	2,682	WP-A30
37	Amortization	Rate Case Expenses	NSPM-Amortization Rate Case Expense	1,640	1,640	WP-A31
38	Amortization	Sherco 3 Depr Deferral	NSPM-Sherco 3 Deferral	694	664	WP-A32
39	Amortization		**Sub-Total Amortization**	**9,554**	**9,274**	
40						
41	Rider Removals	Renewable Connect	NSPM-Remove Renewable Connect	5,086	5,179	WP-A33
42	Rider Removals	Rider: RES	NSPM-RES Rider Removal	0	(0)	WP-A34
43	Rider Removals	Rider: TCR	NSPM-TCR-MN Rider Removal	0	0	WP-A35
44	Rider Removals		**Sub-Total Rider Removals**	**5,086**	**5,179**	
45						
46	Secondary Calculations	ADIT Prorate for IRS	NSPM-ADIT Prorate for IRS	133	144	WP-A36
47	Secondary Calculations	Cash Working Capital	NSPM-Cash Working Capital	(8,487)	(9,400)	WP-A37
48	Secondary Calculations	Net Operating Loss	NSPM-NOL/Credits/199	(3,248)	(1,256)	WP-A38
49	Secondary Calculations		**Sub-Total Secondary Calculations**	**(11,603)**	**(10,511)**	
50						
51			Total Revenue Deficiency	353,253	490,740	

Note: Adjustment amounts in Schedule 12 reflect the revenue requirement calculated at the capital structure proposed in this rate case. See Workpaper A39 for the adjustment due to change in COC.

PRECEDENTIAL ADJUSTMENT SUMMARY

2025 Test Year ($000)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
		Precedential Adjustments														
Line No.		NSPM-Advertising (Trad)	NSPM-Assn Dues (Trad)	NSPM-Aviation	NSPM-Customer Deposits - A&G Expense (Trad)	NSPM-Donations (Trad)	NSPM-Econ Dev Donations (Trad)	NSPM-Econ Develop (Trad)	NSPM-Employee Expenses	NSPM-Foundation Admin	NSPM-Incentive Pay_Remove Long Term	NSPM-Monticello EPU Commission Order No Return	NSPM-Nuclear Retention Removal	NSPM-Pension Non-Qualified Removal	NSPM-Remove NonAsset Trading Fully Allocated Costs	Total
1		WP-A1	WP-A2	WP-A3	WP-A5	WP-A6	WP-A7	WP-A8	WP-A9	WP-A10	WP-A11	WP-A12	WP-A13	WP-A14	WP-A15	
2	Operating Revenues															
3	Retail Revenue															
4	Other Operating											5,582				5,582
5	Total Revenue											5,582				5,582
6																
7	Expenses															
8	Operating Expenses															
9	Power Production										(3,063)		(1,600)			(4,663)
10	Transmission															
11	Customer Accounting															
12	Customer Service and Information															
13	Sales, Econ Dev, & Other						160									160
14	Administrative and General	(3,210)	(375)	(3,331)	37	1,410		(127)	(1,768)	(80)	(13,468)			(338)	(2,131)	(23,382)
15	Total Operating Expenses	(3,210)	(375)	(3,331)	37	1,410	160	(127)	(1,768)	(80)	(16,531)		(1,600)	(338)	(2,131)	(27,885)
16																
17	Taxes															
18	Property															
19	Deferred Income Tax and ITC															
20	Federal and State Income Tax	923	108	968	(11)	(405)	(46)	37	508	23	4,751	1,604	460	97	613	9,630
21	Payroll and Other			(38)						(1)						(39)
22	Total Taxes	923	108	930	(11)	(405)	(46)	37	508	22	4,751	1,604	460	97	613	9,591
23																
24	Total Expenses	(2,287)	(267)	(2,401)	26	1,005	114	(91)	(1,260)	(58)	(11,779)	1,604	(1,140)	(241)	(1,519)	(18,294)
25																
26	Net Income	2,287	267	2,401	(26)	(1,005)	(114)	91	1,260	58	11,779	3,978	1,140	241	1,519	23,876
27																
28	Calculation of Revenue Requirements															
29	Rate Base															
30	Required Operating Income															
31	Operating Income	2,287	267	2,401	(26)	(1,005)	(114)	91	1,260	58	11,779	3,978	1,140	241	1,519	23,876
32	Income Deficiency	(2,287)	(267)	(2,401)	26	1,005	114	(91)	(1,260)	(58)	(11,779)	(3,978)	(1,140)	(241)	(1,519)	(23,876)
33	**Revenue Deficiency**	**(3,210)**	**(375)**	**(3,369)**	**37**	**1,410**	**160**	**(127)**	**(1,768)**	**(82)**	**(16,531)**	**(5,582)**	**(1,600)**	**(338)**	**(2,131)**	**(33,506)**

Northern States Power Company
State of Minnesota Electric Jurisdiction
2026 Plan Year

Docket No. E002/GR-24-320
Exhibit___(BCH-1), Schedule 13
Page 2 of 2

PRECEDENTIAL ADJUSTMENT SUMMARY

2026 Plan Year ($000)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
		Precedential Adjustments														
Line No.		NSPM-Advertising (Trad)	NSPM-Assn Dues (Trad)	NSPM-Aviation	NSPM-Customer Deposits - A&G Expense (Trad)	NSPM-Donations (Trad)	NSPM-Econ Dev Donations (Trad)	NSPM-Econ Develop (Trad)	NSPM-Employee Expenses	NSPM-Foundation Admin	NSPM-Incentive Pay_Remove Long Term	NSPM-Monticello EPU Commission Order No Return	NSPM-Nuclear Retention Removal	NSPM-Pension Non-Qualified Removal	NSPM-Remove NonAsset Trading Fully Allocated Costs	Total
1		WP-A1	WP-A2	WP-A3	WP-A5	WP-A6	WP-A7	WP-A8	WP-A9	WP-A10	WP-A11	WP-A12	WP-A13	WP-A14	WP-A15	
2	Operating Revenues															
3	Retail Revenue															
4	Other Operating											4,371				4,371
5	Total Revenue											4,371				4,371
6																
7	Expenses															
8	Operating Expenses															
9	Power Production										(2,935)					(2,935)
10	Transmission															
11	Customer Accounting															
12	Customer Service and Information															
13	Sales, Econ Dev, & Other						165									165
14	Administrative and General	(3,120)	(358)	(3,400)	37	1,427		(127)	(1,804)	(81)	(14,706)			(336)	(2,132)	(24,601)
15	Total Operating Expenses	(3,120)	(358)	(3,400)	37	1,427	165	(127)	(1,804)	(81)	(17,641)			(336)	(2,132)	(27,370)
16																
17	Taxes															
18	Property															
19	Deferred Income Tax and ITC															
20	Federal and State Income Tax	897	103	989	(11)	(410)	(48)	37	518	24	5,070	1,256		97	613	9,135
21	Payroll and Other			(39)						(1)						(41)
22	Total Taxes	897	103	949	(11)	(410)	(48)	37	518	22	5,070	1,256		97	613	9,094
23																
24	Total Expenses	(2,223)	(255)	(2,451)	26	1,017	118	(91)	(1,285)	(59)	(12,571)	1,256		(240)	(1,519)	(18,276)
25																
26	Net Income	2,223	255	2,451	(26)	(1,017)	(118)	91	1,285	59	12,571	3,115		240	1,519	22,648
27																
28	Calculation of Revenue Requirements															
29	Rate Base															
30	Required Operating Income															
31	Operating Income	2,223	255	2,451	(26)	(1,017)	(118)	91	1,285	59	12,571	3,115		240	1,519	22,648
32	Income Deficiency	(2,223)	(255)	(2,451)	26	1,017	118	(91)	(1,285)	(59)	(12,571)	(3,115)		(240)	(1,519)	(22,648)
33	**Revenue Deficiency**	**(3,120)**	**(358)**	**(3,439)**	**37**	**1,427**	**165**	**(127)**	**(1,804)**	**(82)**	**(17,641)**	**(4,371)**		**(336)**	**(2,132)**	**(31,783)**

Impact of Unused/(Utilized) Tax Deductions on Rate Base	2023 Annual Report EOY Balances	2024 Bridge Annual Activity Amounts	2024 Bridge EOY Balances	2025 Test Year Annual Activity Amounts	2025 Test Year EOY Balances	2026 Plan Year Annual Activity Amounts	2026 Plan Year EOY Balances
1. Unused/(Utilized) Deductions	22,337	(22,337)	0	0	0	0	0
2. Deferred Tax Effect of Unused/(Utilized) Deductions	6,262	(6,262)	0	0	0	0	0
3. Unused/(Utilized) Credits State	1,640	(1,640)	0	0	0	0	0
4. Unused/(Utilized) Credits Federal	758,246	(47,525)	710,721	(66,689)	644,032	(25,807)	618,226
5. Accumulated Deferred Income Taxes (ADIT)	**766,148**	**(55,427)**	**710,721**	**(66,689)**	**644,032**	**(25,807)**	**618,226**

Impact of Unused/(Utilized) Tax Deductions on Revenue Requirements	2024 Bridge Year Utilization Adjustment	2025 Test Year Utilization Adjustment	2026 Plan Year Utilization Adjustment	Comment
6. Deferred Tax Asset BOY	0	0	0	Zero since compliance filing is based on current year activity
7. Deferred Tax Asset EOY	(55,427)	(66,689)	(25,807)	From Unused/(Utilized) columns on Line 5
8. Average Rate Base	(27,713)	(33,345)	(12,903)	(BOY + EOY)/2
9. Return Requirement	(2,095)	(2,521)	(974)	Rate Base * Req Rate of Return
10. RR Tax on Equity Return	(607)	(728)	(282)	(T/(1-T))*RB*Equity Return
11. Rate Base Revenue Requirement	(2,702)	(3,248)	(1,256)	Line 9 + Line 10
12. Deferred Tax	55,427	66,689	25,807	From Unused/(Utilized) columns on Line 5
13. Current Tax Rev Req [1]	(55,166)	(66,689)	(25,807)	From Line 19
14. Annual Revenue Requirement Increase (Reduction)	**(2,441)**	**(3,248)**	**(1,256)**	Line 11+12+13
[1] *Current Income Tax Rev Req Calculation*				
15. Utilized Deductions	22,337	-	-	Unused Annual Deductions
16. Deferred Taxes	55,427	66,689	25,807	Line 12
17. Unused/(Utilized) State Tax Credits	(1,640)	-	-	From Unused/(Utilized) columns on Line 3
18. Unused/(Utilized) Federal Tax Credits	(47,525)	(66,689)	(25,807)	From Unused/(Utilized) columns on Line 4
19. Current Income Tax Revenue Requirement	(55,166)	(66,689)	(25,807)	(T/(1-T))*(-Line 15+.79xLine16+Line17)+.79xLine 16+Line 17

MYRP Forecast Fuel Reconciliation ($000)

Category		2025 Test Year		2026 Plan Year	Comments
FCA Costs					
All Fuel Costs		1,339,593		1,323,271	
PPA Buyouts - FERC 557 Benson		5,114		4,840	
WI Interchange Fuel to MN		10,544		10,614	
Fuel and Purchased Power	**$**	**1,355,250**	**$**	**1,338,726**	BCH-1, Sch. 11a-11b, column 7, row 9
Costs Not Recoverable in Fuel Clause:					
Less Fuel Handling O&M Expenses		19,367		19,408	
Less Non-Asset Based Trading Expenses		35,125		22,381	
Less Off-System Sales Net of Interchange		222,300		222,300	
Less Renewable*Connect Costs		45,945		45,945	
Subtotal	**$**	**322,737**	**$**	**310,034**	
Fuel and Purchased Power in FCA	**$**	**1,032,513**	**$**	**1,028,692**	BCH-1, Sch. 11a-11b, column 35, row 9
PPA Buyout Amortization - FERC 407	$	4,998	$	4,734	BCH-1, Sch. 11a-11b, column 35, row 20
Total Recoverable FCA Costs	**$**	**1,037,511**	**$**	**1,033,426**	
Fuel Revenue					
Minnesota Fuel Costs recovered through FCA		891,200		891,200	BCH-1, Sch. 11a-11b, column 35, row 2
MN Interchange Bill to WI - Variable Fuel		144,686		140,688	
PPA Buyouts Benson - WI Portion in Interchange Rev		1,625		1,537	
Total Fuel Revenue	**$**	**1,037,511**	**$**	**1,033,426**	BCH-1, Sch. 11a-11b, column 35, row 6
Difference in Fuel Costs and Fuel Revenue	**$**	**-**	**$**	**-**	

		2025 Test Year	2026 Plan Year
Base Rates	**X**		
TCR Rider Projects	**P**		
MISO RECB Sch 26 and 26A net revenues**		**P**	**P**
AGIS - ADMS**		**P**	**P**
AGIS - AMI**		**P**	**P**
AGIS - FAN**		**P**	**P**
AGIS - LoadSeer**		**P**	**P**
AGIS - TOU Pilot**		**P**	**P**
Bayfront to Ironwood**		**P**	**P**
Brookings - 2nd Circuit**		**P**	**P**
Hosting Capacity**		**P**	**P**
Participant Compensation**		**P**	**P**
Base Rates	**X**		
RES Rider Projects	**P**		
Grand Meadows Wind Re-Power*		**X**	**X**
Nobles Meadows Wind Re-Power*		**X**	**X**
Northern Wind Farm*		**X**	**X**
Borders Wind Re-Power**		**P**	**P**
Pleasant Valley Wind Re-Power**		**P**	**P**
Sherco Solar I/II **		**P**	**P**
Sherco Solar III**		**P**	**P**
Sherco Battery**		**P**	**P**
Base Rates	**X**		
SEP Rider	**P**		
Prairie Island Indian Community (PIIC) Payments ***		**X**	**X**

* Included in 2025 to 2026 Plan Years with 2025 and 2026 Interim rate adjustments to exclude from Interim rates; to be recovered in base rates and removed from the Riders at conclusion of the case.

** Removed from 2025 to 2026 Plan Year revenue requirement calculations (revenues and expenses), projects continue recovery in the RES and TCR Riders. after the conclusion of the rate case.

*** The Prairie Island Indian Community (PIIC) Payments are currently recovered in the SEP rider. We are proposing to roll future payments into base and interim rates effective 1/1/2025.

Rebuttal Testimony and Schedules
Benjamin C. Halama

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-24-320
Exhibit___(BCH-3)

Overall Revenue Requirements

October 10, 2025

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Benjamin C. Halama. I am the Director of Revenue Analysis for Xcel Energy Services Inc. (XES or the Service Company), the service company for Xcel Energy Inc. and its operating company subsidiaries.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS PROCEEDING?

A. Yes. On November 1, 2024, I filed Direct Testimony on behalf of Northern States Power Company–Minnesota (NSPM or the Company), supporting the Company's Minnesota jurisdictional electric operations costs of service, revenue requirements, and revenue deficiency for each of the two years of the Company's multi-year rate plan (MYRP), which are calendar years 2025 (the test year) and 2026 (the plan year).

I provided financial data supporting the overall revenue deficiency for the State of Minnesota retail electric jurisdiction, including a description of cost changes, the data we provided, and our selection of the test year and plan year. I also presented our jurisdictional cost of service study and the revenue requirement effects of our utility and jurisdictional allocations and our revenue requirement, including rate base and income statement components with related adjustments and amortizations.

I also supported the 2025 and 2026 requested interim rate increases discussed in the Company's Petition for Interim Rates and I explained our treatment of riders and identified certain compliance requirements addressed in our general rate filing.

On March 17, 2025, I filed Supplemental Direct Testimony providing restated revenue requirements based on various updates. I provided an update to the cost-of-service study for the Company's wildfire mitigation activities and the proposed Residential Arrears Management Program (RAMP). I also accounted for the correction of errors in employee expenses, interchange revenue and expense, and a FERC account reclassification for the Transmission Cost Recovery (TCR) Rider Removal for operations and maintenance (O&M) expense.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My Rebuttal Testimony and supporting schedules update the Company's rate case financial statements for the 2025-2026 MYRP to reflect those adjustments recommended or accepted by the Company, as well as summarize the Company's response to adjustments presented by other parties with which the Company does not agree. While I address some of those MYRP adjustments in detail, in other cases I identify the proposed adjustment, provide any quantification or corrections, and identify the witness who provides the substantive response to the proposed adjustment.

Overall, my Rebuttal Testimony supports the Company's updated Minnesota jurisdiction electric operations cost of service, revenue requirements, and revenue deficiency for each of the two years of the Company's MYRP, which includes the 2025 test year and the 2026 plan year. The Company's Rebuttal net deficiencies and retail revenue requirements request for the test year and plan year are set forth in Exhibit___(BCH-3), Schedules 1 and 2 to my Rebuttal Testimony, with the Minnesota jurisdictional deficiencies summarized in Table 1 below.

Table 1
2025-2026 Revenue Requests
Minnesota Jurisdictional Deficiency Net of Interchange ($s in millions)

MYRP Year	2025	2026
Incremental Annual Deficiency ($)	$208.4	$156.9
Incremental Annual Deficiency (%)*	5.8%	4.2%

*This is calculated using the annual revenue request over the forecasted present revenues in each applicable year, less prior year(s).

Q. WERE THE SCHEDULES PRESENTED WITH YOUR REBUTTAL TESTIMONY PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

Q. ARE THERE OTHER WITNESSES YOU RELIED UPON IN DEVELOPING YOUR TESTIMONY?

A. Yes. I refer to the Rebuttal Testimony of various other Company witnesses in this proceeding to support the Company's position.

Q. HOW IS THE REMAINDER OF YOUR REBUTTAL TESTIMONY ORGANIZED?

A. The remainder of my Rebuttal Testimony is organized as follows:

- Section II. Updated Rebuttal Revenue Deficiency
- Section III. Intervenor Adjustments Opposed by the Company
- Section IV. Trackers
- Section V. Conclusion

II. UPDTATED REBUTTAL REVENUE DEFICIENCY

A. Company Proposed or Accepted Adjustments

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR REBUTTAL TESTIMONY?

A. In this section of my Rebuttal Testimony I identify and quantify the individual adjustments included in the Company's rebuttal revenue requirement, which include those to which we agree in response to intervenor Direct Testimony; those identified in other dockets; and those that were previously identified by the Company in Direct Testimony, Supplemental Direct Testimony, or in response to discovery in this case, that were not previously included in the Company's revenue requirements.

1. Community Solar Gardens Electric Revenue

Q. WHAT ADJUSTMENT IS THE COMPANY MAKING WITH RESPECT TO COMMUNITY SOLAR GARDENS ELECTRIC REVENUE?

A. In the Company's May 5, 2025 Comments in Docket Nos. E002/CI-23-335 and E002/M-13-867 related to the Company's Community Solar Garden (CSG) program, the Company noted that the full Information Technology (IT) capital investments associated with consolidated billing functions for the Low-to-Moderate Income Accessible CSG program were included in the 2025 test year and 2026 plan year. These costs were included in Exhibit___(MNS-1), Schedule 2 to the Direct Testimony of Company witness Megan N. Scheller. The Comments also noted that in Rebuttal Testimony, the Company would update the other revenue forecast to align with the latest approved CSG fee structure. This accounting ensures that the Company recovers the cost of this project but also ensures that the cost is paid (over time) by the cost causers. This adjustment will result in an increase in other revenues in the 2025 test year and 2026 plan year, and a decrease to revenue requirements.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Exhibit___(BCH-3), Schedules 3A and 3B, page 2, row 84, column 8 with this testimony.

2. Customer Advances

Q. WHAT ADJUSTMENT IS THE COMPANY MAKING WITH RESPECT TO CUSTOMER ADVANCES?

A. As discussed in my Direct Testimony, customer advances are based on actual 13-month average balances as a proxy for the 2025-2026 MYRP. The Company discovered that the amount for customer advances included in the MYRP was based on the 13-month period ending December 2023, but the amount should have been based on the 13-month period ending June 2024. Thus, an adjustment is needed to reflect the correct amount for customer advances in the 2025 test year and 2026 plan year, based on the 13-month period ending June 2024.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 2, row 84, column 9 with this testimony.

3. Nuclear Decommissioning Accrual

Q. DID THE COMPANY INCLUDE AN ACCRUAL AMOUNT FOR NUCLEAR DECOMMISSIONING IN THE MYRP?

A. Yes. As discussed in the Direct Testimony of Company witness Allison M. Johnson, the Company included $21.6 million (Minnesota jurisdiction) as the annual nuclear decommissioning accrual amount for 2025 and 2026.

Q. WHAT WAS PROPOSED BY INTERVENORS IN RELATION TO THE NUCLEAR DECOMMISSIONING ACCRUAL?

A. Department of Commerce, Division of Energy Resources (Department) witness Andrew Golden recommends that the Company adjust the annual decommissioning accrual amount to approximately $3.8 million, based on the Commission's May 14, 2025 Order in the Company's Triennial Nuclear Decommissioning proceeding in Docket No. E002/M-24-394. This recommendation would result in an annual revenue requirement reduction of approximately $17.7 million in 2025 and 2026.[1]

Q. DOES THE COMPANY AGREE WITH THIS RECOMMENDED ADJUSTMENT?

A. Yes. As Company witness Mark P. Moeller discusses in his Rebuttal Testimony, the Department's recommendation accurately reflects the Commission's May 14, 2025 nuclear decommissioning Order, and the Company agrees with this adjustment.

Q. APART FROM THE CONCEPTUAL AGREEMENT WITH THIS ADJUSTMENT, DO YOU SUPPORT A FURTHER ADJUSTMENT FOR THE NUCLEAR DECOMMISSIONING ACCRUAL?

A. Yes. As Company witness Moeller also discusses in his Rebuttal Testimony, the Company also agrees with the Department's recommendation related to extending the depreciable lives of the Monticello and Prairie Island nuclear

[1] Ex. DOC-___ at 3-4 (Golden Direct).

plants to align with the operational lives of these plants for planning purposes approved by the Commission's April 21, 2025 Order in the Company's 2024-2040 Integrated Resource Plan (IRP) (Docket No. E002/RP-24-67). As such, the extension of the nuclear remaining lives will further decrease the annual nuclear decommissioning amount, resulting in an annual accrual amount of zero for both 2025 and 2026.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 2, row 84, column 10 with my testimony.

4. Transmission, Distribution, and General (TD&G) Depreciation

Q. WHAT ADJUSTMENT IS THE COMPANY PROPOSING RELATED TO TD&G DEPRECIATION?

A. As discussed in the Rebuttal Testimony of Company witness Moeller, the Company is making adjustments related to FERC Account 370 Meters – AGIS Remaining Life and FERC Account 390 – Structures and Improvements Remaining Life. These adjustments decrease overall depreciation expense.

These adjustments impact the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 2, row 84, column 11 with my testimony.

5. Distributed Intelligence My Energy Connection (MEC) 3.0

Q. WHAT ADJUSTMENT IS THE COMPANY MAKING WITH RESPECT TO DISTRIBUTED INTELLIGENCE MEC 3.0?

A. After filing this case, the Company identified that the MEC 3.0 project had been incorrectly allocated 100 percent to NSPM but should have been allocated across all operating companies, with only 34.4 percent of costs allocated to NSPM. Thus, an adjustment is needed to remove 65.6 percent of projects from NSPM, which are assigned to other operating companies.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 2, row 84, column 12 with this testimony.

6. Distributed Intelligence

Q. WHAT ADJUSTMENT IS THE COMPANY PROPOSING RELATED TO DISTRIBUTED INTELLIGENCE?

A. As I discussed in my Direct Testimony, as the Company was completing validation of the revenue requirement, we identified one non-NSPM distributed intelligence project that was inadvertently included in the MYRP Forecast. The removal of this project will decrease the overall revenue requirement deficiency by approximately $0.2 million in 2025 and 2026. Our interim rate petition did not include distributed intelligence projects, and we indicated we would remove the $0.2 million from the MYRP Forecast in rebuttal testimony.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 2, row 84, column 13 with this testimony.

7. Employee Expenses

Q. What adjustment is the Company proposing related to employee expenses?

A. As the Company indicated in its response to Office of the Attorney General – Residential Utilities Division (OAG) Information Request (IR) No. 1017, certain travel costs related to the Company's involvement in Energy Impact Partners (EIP) were inadvertently excluded from the Employee Expense Adjustment for the 2025 test year. The Company noted we would make an adjustment to add $15,103 to the Employee Expense Adjustment for the 2025 test year and 2026 plan year, which will reduce the 2025 and 2026 revenue requirements.

Similarly, the Company's response to OAG IR No. 1018 noted that certain travel costs related to the Company's involvement in the Carbon Free Power Project (CFPP) were also inadvertently excluded from the Employee Expense Adjustment for the 2025 test year. The Company noted we would make an adjustment to add $8,793 to the Employee Expense Adjustment for the 2025 test year and 2026 plan year, which will reduce the 2025 and 2026 revenue requirements.

These adjustments impact the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 2, row 84, column 14 with this testimony.

8. Nuclear End-of-Life Fuel Accrual

Q. Did the Company include a nuclear end-of-life fuel accrual amount in the MYRP?

A. Yes. As discussed in the Direct Testimony of Company witness Johnson, the Company included $714,366 (Minnesota jurisdiction) as the annual nuclear end-of-life fuel accrual amount for 2025 and 2026.

Q. WHAT WAS PROPOSED BY INTERVENORS IN RELATION TO THE NUCLEAR END-OF-LIFE FUEL ACCRUAL?

A. Similar to the recommendation related to the nuclear decommissioning accrual amount discussed above, Department witness Golden recommends that the Company adjust the annual decommissioning accrual amount to $455,460, based on the Commission's May 14, 2025 Order in the Company's Triennial Nuclear Decommissioning proceeding. This recommendation results in an annual revenue requirement reduction of $258,906 in 2026 and 2026.[2]

Q. DOES THE COMPANY AGREE WITH THIS RECOMMENDED ADJUSTMENT?

A. Yes. As Company witness Moeller discusses in his Rebuttal Testimony, the Department's recommendation accurately reflects the Commission's May 14, 2025 nuclear decommissioning Order, and the Company agrees with this adjustment.

Q. APART FROM THE CONCEPTUAL AGREEMENT WITH THIS ADJUSTMENT, DO YOU SUPPORT A FURTHER ADJUSTMENT THAT NEEDS TO BE REFLECTED FOR NUCLEAR END-OF-LIFE FUEL ACCRUAL?

A. Yes. As Company witness Moeller also discusses in his Rebuttal Testimony, the Company also agrees with the Department's recommendation related to extending the depreciable lives of the Monticello and Prairie Island nuclear

[2] Ex. DOC-___ at 4-5 (Golden Direct).

plants as described above. As such, the extension of the nuclear remaining lives will further decrease the annual nuclear decommissioning amount, resulting in an annual accrual amount of $154,695 for 2025 and $159,688 for 2026.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 2, row 84, column 15 with this testimony.

9. Electric Vehicle (EV) Program

Q. WHAT ADJUSTMENT IS THE COMPANY MAKING RELATED TO THE EV PROGRAM?

A. As discussed in my Direct Testimony, in the Company's 2023 Transportation Electrification Plan (TEP), the Commission approved the Company's proposed IT costs of $2.4 million in capital expenditures and $0.9 million in O&M expenditures for the period 2024-2027, modified to be consistent with the EV programs approved in the TEP. After the cost of service was completed, we discovered that a portion of these approved IT capital costs for 2025 and 2026 was inadvertently excluded from the MYRP budget in this case. The capital investments included in the MYRP are described in the Direct Testimony of Company witness Marty D. Mensen and the O&M costs are described in the Direct Testimony of Company witness Gregory J. Robinson. Our rebuttal cost of service is updated to include these EV program costs.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 2, row 84, column 16 with this testimony.

10. Generation Capacity Revenues

Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO GENERATION CAPACITY REVENUES IN THE MYRP?

A. As I discussed in my Direct Testimony, the Company included budgeted amounts for Midcontinent Independent System Operator (MISO) capacity auction revenues and bilateral capacity contracts as a baseline for capacity revenues in the 2025 test year. The Company also proposed to carry capacity revenues and expenses in a tracker, similar to the capacity revenue tracker implemented in the Company's last electric rate case. The amounts included in the 2025 test year and 2026 plan year establish the baseline revenue and expense amounts in base rates.

Q. WHAT WAS PROPOSED BY INTERVENORS IN RELATION TO CAPACITY REVENUES?

A. Department witness Golden recommends that the Company update the baseline capacity revenue amounts in the 2025 test year and 2026 plan year based on updated MISO Planning Resource Auction (PRA) results that were not available at the time of the Company's initial filing, and Department witness Golden agrees that these amounts will be subject to true-up in the Company's annual capacity tracker filings.[3]

Q. DOES THE COMPANY AGREE WITH THIS RECOMMENDED ADJUSTMENT?

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[3] Ex. DOC-___ at 13-14 (Golden Direct).

A. Yes. The Company agrees it is reasonable to update the capacity revenue baseline amounts included in 2025 and 2026 as Department witness Golden recommends.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 2, row 84, column 17 with this testimony.

11. *Hosting Capacity*

Q. WHAT ADJUSTMENT IS THE COMPANY MAKING RELATED TO HOSTING CAPACITY?

A. The Company is making an adjustment to remove Distribution's hosting capacity capital budget from the 2026 plan year when these investments were expected to begin. As discussed in the Rebuttal Testimony of Company witness Mensen, there are two separate proceedings before the Commission that will identify specific hosting capacity projects for implementation. Because the timing of these proceedings is now known and it is not expected that they will identify specific projects for implementation in 2026, the Company is making an adjustment to remove the hosting capacity budget from this rate case. This results in a reduction of approximately $15.2 million to Distribution's capital budget for 2026 ($7.6 million in average rate base for 2026).

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 2, row 84, column 18 with this testimony.

12. Late Payment Revenue

Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO LATE PAYMENT REVENUE IN SUPPLEMENTAL DIRECT IN THIS CASE?

A. As described in my Supplemental Direct, we adjusted the 2025-2026 MYRP to reflect removal of late payment revenue from the cost of service, as we proposed to use these amounts to fund the new RAMP as a result of the Commission's January 13, 2025 Order in Docket No. E002/M-24-27.

Q. WHAT DID THE DEPARTMENT PROPOSE IN RELATION TO LATE PAYMENT REVENUES?

A. Department witness Andy Bahn concludes that the final order for the current MYRP will not be issued until sometime in 2026 and therefore the RAMP program will not be effective and available to assist eligible customers in 2025. For this reason, Department witness Bahn recommends that Other Operating Revenues for the 2025 test year should include $6.1 million in residential late payment charges.[4] Department witness Bahn further recommends that because the RAMP program will not be available for the entire 2026 plan year that at least $2.9 million should be included in Other Operating Revenues for the plan year, 2026.[5]

Q. DOES THE COMPANY AGREE WITH THIS RECOMMENDED ADJUSTMENT?

A. The Company agrees with the Department's recommended adjustment for test year 2025. The Company disagrees with the Department's recommendation for 2026 because if the program is approved in July of 2026

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[4] Ex. DOC-___ at 67 (Bahn Direct).

[5] Ex. DOC-___ at 70 (Bahn Direct). As noted below, Citizens Utility Board of Minnesota (CUB) witness Annie Levenson-Falk also provides recommendations regarding late payment revenues, which are addressed in the Rebuttal Testimony of Company witness Nicholas F. Martin.

as expected, the Company will be able to use the full funding amount to benefit customers in 2026. As described in the Supplemental Direct Testimony of Company witness Nora C. Lindgren, the Company proposed to calculate the total amount of residential late payment fees and to provide lump sum benefits based on available funding. As a result, the timing of when the RAMP program is implemented in 2026 should not impact the amount of funding applied in 2026.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 4, row 84, column 19 with this testimony.

13. Luverne Battery Reallocation

Q. WHAT ADJUSTMENT IS THE COMPANY MAKING RELATED TO THE LUVERNE BATTERY REALLOCATION?

A. As discussed in the Direct Testimony of Company witness Johnson, the Commission's Order dated July 27, 2023 in the Company's last MYRP, Docket No. E002/GR-21-630, Order Point 19, approved a reserve reallocation of no more than $2.14 million of a reasonable cost to dismantle, dispose of, and fully restore the site associated with the Luverne Wind2Battery system. Further, Order Point 19 required the Company to perform the proposed "inverse reallocation" if actual costs are lower than $2.14 million to return unused amounts back to the groups they came from in a future proceeding.

The final removal project costs were not known in time to be included in the cost of service in this case. In our initial filing, the Company estimated the final removal costs to be just over $1.2 million and performed an "inverse reallocation" for the difference between the authorized $2.14 million and the estimated removal costs of $1.2 million. The Company also noted we would provide an update in rebuttal of any difference between the estimated and actual removal costs. As discussed in the Rebuttal Testimony of Company witness Moeller, the actual removal costs were approximately $0.05 million more than estimated. The Company is making the appropriate adjustment to decrease the reallocation portion increasing the rebuttal revenue requirement.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 4, row 84, column 20 with this testimony.

14. Nuclear Production Tax Credits (PTCs)

Q. WHAT ADJUSTMENT IS THE COMPANY PROPOSING RELATED TO NUCLEAR PTCS?

A. As discussed in my Direct Testimony, at the time of our direct filing, based on the uncertainty of the actual PTC value the Company would receive and potential guidance from the Internal Revenue Service (IRS), the Company did not include any nuclear PTCs in the MYRP Forecast cost of service. I also noted that the Company would update the 2025-2026 cost of service in this proceeding when additional information is available.

The Company provided a forecast for 2026 nuclear PTCs in its 2026 Fuel Forecast Petition filed on May 1, 2025 in Docket No. E002/AA-25-63, and the Company is incorporating the most recent forecast into the rebuttal cost of service in this case. I also note that the Commission's July 17, 2023 Order in the Company's last electric rate case (Docket No. E002/GR-21-630) approved the Company's proposal to include a nuclear PTC tracker and refund in the Fuel Clause. As such, this adjustment reflects the PTC refund in the Fuel Clause and is included in the rebuttal cost of service to ensure all secondary calculations are accurate. Any difference between the nuclear PTC forecast and actuals for 2026 will be included in the tracker for refund in the Fuel Clause.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 4, row 84, column 21 with this testimony.

15. Solar Production Tax Credits – Allocation

Q. WHAT ADJUSTMENT IS THE COMPANY PROPOSING RELATED TO THE SOLAR PTC ALLOCATION?

A. As I discussed in my Direct Testimony, as the Company was completing validation of the allocation of tax credits among jurisdictions, we identified that solar PTCs had been allocated using the Minnesota jurisdictional demand allocator. The Company should have allocated solar PTCs consistent with the RES Rider based on the Minnesota jurisdictional energy allocator due to their variable nature.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 4, row 84, column 22 with this testimony.[6]

[6] As reflected in Schedules 3A and 3B, the adjustments are approximately $0.084 million in 2025 and $0.164 million in 2026. These amounts differ slightly from the rebuttal corrections that had been

16. Federal Production Tax Credits

Q. WHAT WAS PROPOSED BY THE COMPANY IN ITS INITIAL FILING RELATED TO FEDERAL PTCS?

A. As discussed in my Direct Testimony, the Company requested PTC treatment consistent with the previously approved process. Specifically, we proposed setting a new baseline PTC amount in base rates for each year of the MYRP, 2025 and 2026. The difference between actual and baseline PTCs would be recorded in the Renewable Energy Standard (RES) Tracker account, and the difference would be either refunded to or recovered from customers through the RES Rider, pursuant to Commission review and approval in future RES Rider filings.

Q. WHAT WAS PROPOSED BY INTERVENORS IN RELATION TO THE PTCS?

A. Department witness Ashley Uphus agrees with the Company's proposal to continue to use a true-up mechanism for PTCs in the RES Rider.[7] However, she recommends that the Company's PTC forecasts should be updated based on the Company's updated PTC forecast provided in response to Department IR No. 1194, provided in Attachment AU-D-1 to Department witness Uphus' Direct Testimony.[8] This update reflects the Company's updated February 2025 PTC forecast, and reflects the current PTC rates issued by the IRS on May 27, 2025. Department witness Uphus recommends an adjustment that would increase the baseline PTC amount included in the MYRP. Since the PTCs are a cost of service offset, the recommended increase in the baseline

identified in my Direct Testimony at pages 96-97 and computed in Ex. Xcel-___, Vol. 4, MYRP Workpapers, III. P8-1 (Production Tax Credits) (of approximately $0.069 million and $0.136 million respectively) due to an error adjusting the rebuttal correction interchange revenue, which should have been held constant. The corrected adjustment is reflected in Schedules 3A and 3B page 4, row 84, column 22.

[7] Ex. DOC-___ at 6 (Uphus Direct).

[8] Ex. DOC-___ at 7-8 and Schedule AU-D-1 at 1-9 (Uphus Direct).

PTC amounts would result in a reduction to the cost of service of approximately $21.5 million and $10.4 million over the MYRP.

Q. DOES THE COMPANY AGREE WITH THIS ADJUSTMENT CONCEPTUALLY?

A. Yes. Although there is a true-up between the level of PTCs included in base rates through this MYRP and the actual amount of PTCs earned in the respective period that would occur through the RES Rider, it is reasonable that the Company update the baseline PTC level in base rates based on the most recent forecast.

Q. APART FROM THE CONCEPTUAL AGREEMENT, DOES THE COMPANY AGREE WITH THE DEPARTMENT'S CALCULATION OF ITS ADJUSTMENT?

A. No. The adjustment Department witness Uphus proposes does not accurately account for the rebuttal adjustment to update the allocation of solar PTCs that was described in my Direct Testimony.[9] The corrected amounts are presented in Exhibit___(BCH-3), Schedule 4 to my Rebuttal Testimony.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 4, row 84, column 23 with this testimony.

17. Reconnection Fees

Q. WHAT ADJUSTMENT IS THE COMPANY PROPOSING RELATED TO RECONNECTIONS?

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[9] Ex. Xcel-___ at 96-97 (Halama Direct) ("PTCs had been allocated using the Minnesota jurisdictional demand allocator. The Company should have allocated solar PTCs consistent with the RES Rider based on the Minnesota jurisdictional energy allocator due to their variable nature.").

A. As discussed in the Rebuttal Testimony of Company witness Martin, in the Safety, Reliability, and Service Quality (SRSQ) docket for 2024, we worked with CUB and the Energy CENTS Coalition (ECC) to develop a plan to use Advanced Metering Infrastructure (AMI) to suspend disconnections during periods of poor air quality, and to reconnect previously disconnected customers during extreme heat and poor air quality. The Company initially proposed a 16-month implementation timeframe to allow for necessary system enhancements and customer messaging. The Commission's July 25, 2025 Order in Docket No. E002/M-25-27 approved the Company's proposal and ordered the changes to be implemented beginning in 2026.[10] As a result, the Company is including costs in the rebuttal revenue requirement to implement the changes as approved by the Commission's July 25, 2025 Order.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 4, row 84, column 24 with this testimony.

18. Remaining Lives and Net Salvage Rates – Production

Q. WHAT ADJUSTMENT IS THE COMPANY PROPOSING RELATED TO UPDATED NET SALVAGE RATES?

A. As discussed in Company witness Johnson's Direct Testimony, the Company filed its 2024 Annual Remaining Lives (ARL) filing on September 9, 2024 in Docket No. E,G002/D-23-356 utilizing a preliminary dismantling study. The Company filed its final 2024 Dismantling Study on January 31, 2025, and updated the ARL filing at that time to reflect the updated removal costs and

[10] *In the Matter of Northern States Power Co. d/b/a Xcel Energy's 2024 Annual Safety, Reliability, and Service Quality Report*. Docket No. E-002/M-25-27, ORDER (July 25, 2025).

associated net salvage rates. Company witness Johnson also noted that the Company would include any changes to depreciation expenses associated with the final 2024 Dismantling Study in Rebuttal Testimony. Company witness Moeller addresses these changes in his Rebuttal Testimony. These changes have been incorporated into the rebuttal revenue requirement.

Q. IS THE COMPANY PROPOSING ANY OTHER ADJUSTMENTS RELATED TO THE 2024 ARL FILING?

A. Yes. As Company witness Moeller also discusses in his Rebuttal Testimony, the 2024 ARL filing requested to extend the depreciation lives of the Hennepin Island and Upper Dam Hydro facilities, and these extended lives were reflected in the depreciation rates include in the Company's initial filing in this rate case. However, the Department recommended no life extension for these hydro facilities, and the Company did not object to this recommendation. The depreciation expense impact of this adjustment is an increase of approximately $1.6 million in 2025 and $2.1 million in 2026, which is reflected in the rebuttal revenue requirement.[11]

These adjustments impact the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 4, row 84, columns 25 and 27 with this testimony.

[11] *See In the Matter of Xcel Energy's 2023 Annual Review of Remaining Lives and Depreciation Rates for Electric and Gas Production and Gas Storage Facilities & for Transmission, Distribution, and General Accounts*, Docket No. E,G002/D-23-356, Xcel Energy Reply Comments at 2 (Sept. 19, 2025) ("We do not object to this recommendation. The depreciation expense impact of this adjustment is an increase of $1,535,305. The Company's currently pending electric rate case in Docket No. E002/GR-24-320 assumes the extended depreciation lives; therefore, we will make a rebuttal adjustment in the rate case to account for this Department recommendation.").

19. Remaining Lives – Nuclear

Q. WHAT ADJUSTMENT IS THE COMPANY MAKING WITH RESPECT TO DEPRECIATION EXPENSE FOR THE EXTENSION OF THE DEPRECIABLE LIVES OF THE MONTICELLO AND PRAIRIE ISLAND NUCLEAR PLANTS?

A. The Company is making an adjustment to depreciation expense related to extending the depreciable lives of the Monticello and Prairie Island nuclear plants to align with the operational lives of these plants approved by the Commission in its April 21, 2025 Order in the Company's 2024-2040 IRP (Docket No. E002/RP-24-67).

Q. DID INTERVENORS MAKE RECOMMENDATIONS RELATED TO THE REMAINING LIVES OF THESE NUCLEAR PLANTS?

A. Yes. Department witness Holly Jones recommends that the Company match the depreciable lives with operating lives of these plants approved in the Company's 2024-2040 IRP.[12]

Q. DOES THE COMPANY AGREE WITH THE CALCULATED AMOUNTS PRESENTED BY THE DEPARTMENT?

A. Yes. The amounts presented by the Department are consistent with the amounts provided by the Company (see Department witness Jones attachment HDJ-D-6). Company witness Moeller also addresses this adjustment in his Rebuttal Testimony.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 4, row 84, column 26 with this testimony.

[12] Ex. DOC-___ at 15-16 (Jones Direct).

20. TCR Rider Removal FERC Reclassification

Q. WHAT ADJUSTMENT IS THE COMPANY PROPOSING RELATED TO TCR RIDER REMOVAL FERC RECLASSIFICATION?

A. As the Company discussed in its response to OAG IR No. 7003, the Company recovers AMI meters in the TCR Rider. The cost of AMI meters included in the 2025 test year and 2026 plan year are the internal labor costs, which are not includable for recovery in the TCR. The internal labor plant investment ending balance for AMI meters is $5.1 million in the 2025 test year and $5.9 million in the 2026 plan year. While researching this discovery request, the Company realized the rider removal process to remove the portion of AMI meters being recovered in the TCR incorrectly removed the ending plant balance from underground lines (FERC 367) instead of from meters (FERC 370). The Company noted it would adjust for this in rebuttal. This change will have no impact on any line in the rebuttal cost of service, but it will move costs between these two FERC accounts and will impact the class cost of service.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 4, row 84, column 28 with this testimony.

21. TCR Rider Removal Update

Q. WHAT ADJUSTMENT IS THE COMPANY PROPOSING RELATED TO TCR RIDER REMOVAL UPDATE?

A. As explained in my Direct Testimony, the TCR Rider removal adjustment removes all costs and revenues from the MYRP Forecast jurisdictional cost of service with the exception of internal labor on all rider projects. During discovery, the Company identified an error in the calculation of internal labor amounts for the forecasted periods in the AMI project. This resulted in the capital cost component of the TCR Rider removal not fully removing all AMI capital costs to be recovered in the TCR Rider revenue. The Company is making an adjustment to remove the additional costs and the equivalent rider revenues included in the MYRP cost of service.

This adjustment decreases the MYRP Forecast rate base and expense but has a net zero impact on the MYRP Forecast revenue requirements, as we expect full recovery in the TCR Rider. The rider removal impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 4, row 84, column 29 with this testimony.

Q. DOES THIS ADJUSTMENT RESULT IN ANY OTHER IMPACTS TO THE REBUTTAL COST OF SERVICE?

A. Yes, the amount of TCR rider revenue was understated; therefore, to remain consistent with the rider removal an adjustment was made to increase TCR rider revenue.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 4, row 84, column 30 with this testimony.

22. Sales Forecast Update

Q. WHAT DID THE COMPANY PROPOSE IN ITS INITIAL FILING IN RELATION TO THE SALES FORECAST IN THIS CASE?

A. While the Company developed a 2025 test year and 2026 plan year sales forecast based on sound methodologies, we also proposed using actual 2025 sales data when it becomes available to establish the revenue requirement for the test year and to provide an updated 2026 plan year sales forecast that incorporates additional data. Company witness Benjamin S. Levine discusses the updated 2025 and 2026 sales forecasts in his Rebuttal Testimony. As discussed by Company witness Levine, Xcel Energy's projection of 2025 total sales decreased by 0.4 percent and 2026 total sales decreased 1.4 percent, as compared to the forecast presented by Company witness Levine in Direct Testimony. The updated sales forecasts were used to develop the revenue forecasts presented in the Rebuttal Testimony of Company witness Nicholas N. Paluck.

Q. DOES THIS PROPOSAL HAVE ANY IMPACT ON THE COMPANY'S REVENUE REQUIREMENT FOR THE MYRP?

A. Yes. The Company has incorporated the impacts of the updated 2025 and 2026 sales forecasts and associated revenue impacts in the rebuttal revenue requirements. This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 4, row 84, column 31 with this testimony. The revenue requirement for 2025 will need to be further updated when a full year of actual data becomes available.

23. Service Quality

Q. WHAT ADJUSTMENT IS THE COMPANY PROPOSING RELATED TO SERVICE QUALITY?

A. The Company has incorporated costs in the 2025-2026 MYRP to comply with the Commission's January 13, 2025 Order in the Company's 2023 SRSQ.

Order Point 46 of the Commission's January 13, 2025 Order Accepting Reports and Setting Additional Requirements in Docket No. E002/M-24-27 required that the Company hire an independent third-party evaluator with expertise in evaluating racial disparities to conduct a one-year study that will evaluate Xcel Energy's practices and policies related to capital investment planning, outage restoration practices, and shutoff practices to better understand the causes of these discrepancies in shutoff rates and service reliability. As described in the Rebuttal Testimony of Company witness Martin, the Company has now completed a Request for Proposal to select this third-party evaluator and will be working with the evaluator and interested stakeholders in accordance with the Commission's order.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 4, row 84, column 32 with this testimony.

24. Sherco Inventory

Q. WHAT DID THE COMPANY PROPOSE IN RELATION TO OBSOLETE INVENTORY ASSOCIATED WITH SHERCO UNIT 1?

A. As discussed in the Direct Testimony of Company witness Randy A. Capra, the Company proposed to include a one-time $8.1 million obsolete inventory write-off in 2026 from the retirement of Sherco Unit 1.

Q. WHAT WAS PROPOSED BY INTERVENORS IN RELATION TO THE SHERCO UNIT 1 INVENTORY?

A. Department witness Mark Johnson agreed it is appropriate to write-off the obsolete inventory, but disagreed with reflecting the entire write-off in a single year. Department witness Johnson recommends the Company instead amortize the amount over a three-year period, beginning in 2026. Department witness Johnson indicates this would be similar to the Company's proposal to amortize rate case expenses over a three-year period.[13]

Q. DOES THE COMPANY AGREE WITH THIS RECOMMENDATION?

A. The Company agrees with the concept of amortizing the write-off amount over a three-year period, but the Company recommends the three-year amortization period begin in 2025, which would align with the Company's proposed amortization period for rate case expenses. The Company's rebuttal revenue requirement reflects amortization of the $8.1 million over three years beginning in 2025.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 4, row 84, column 33 with this testimony.

25. Time of Use (TOU) Rate Implementation

Q. WHAT ADJUSTMENT IS THE COMPANY PROPOSING RELATED TO IMPLEMENTATION OF ITS RESIDENTIAL TOU RATE?

A. The Company is proposing an adjustment related to the capital costs associated with implementing the residential TOU rate. Our initial rate case proposal included the O&M costs necessary to implement the rate but did not include the capital costs related to technical implementation. Development of a technical implementation plan was completed after the Commission

[13] Ex. DOC-__ at 39-40 (Johnson Direct).

approved our rate proposal, which occurred after our initial filing in this rate case.[14]

Technical implementation work will include billing system configuration to ensure rate implementation is properly implemented and developing other program components. The capital cost activities needed to implement the proposal as approved include the following:

- Setting up new rates in the Customer Resource System (CRS), which is the Company's customer information system, and other integrated systems;
- Developing programs to support customers that elect to opt-in to the rate, transitioning customers from the current TOU pilot rate to the new TOU rate, and automation of meter exchanges for customers on a TOU rate;
- Implementing changes to allow participation by net-metered customers with rooftop solar, customers enrolled in the Saver's Switch program, and customers enrolled in Renewable*Connect;
- Developing necessary programs to support EV programs; and
- Unit and user testing of all new programs.

Beyond these activities, the Company will also need to purchase software licenses to support new programs and will incur development costs for a new Rate Comparison Tool. The implementation capital costs totaling $3.2 million,

[14] *In the Matter of the Petition of Xcel Energy for Approval of Residential Time of Use Rate Design*, Docket No. E002/M-23-524, ORDER APPROVING REVISED OPT-IN PROPOSAL AND SETTING REPORTING REQUIREMENTS (May 15, 2025).

along with the O&M budget included in our original proposal, are incorporated into the rebuttal revenue requirement.

The TOU capital cost adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 4, row 84, column 34 with this testimony.

26. Wildfire Mitigation Pole Loading Clearance (PLC) Update

Q. WHAT ADJUSTMENT IS THE COMPANY PROPOSING RELATED TO THE WILDFIRE MITIGATION PLC PROGRAM?

A. As noted in my Supplemental Direct Testimony, the Company identified a difference in the wildfire mitigation PLC program capital and O&M budget amounts presented in the Supplemental Direct Testimony of Company witnesses Anne Z. Sherwood and Kelly A. Bloch and the amounts reflected in my Supplemental Direct Testimony and Schedules. The 2026 rebuttal revenue requirement now reflects the amounts presented by Company witness Bloch in Supplemental Direct Testimony.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 4, row 84, column 35 with this testimony.

B. Secondary Calculations

1. ADIT Prorate – IRS Required

Q. PLEASE DESCRIBE THE ADIT PRORATE ADJUSTMENT THAT IS REQUIRED BY THE IRS AND INCLUDED IN THESE SECONDARY CALCULATIONS.

A. In general, the IRS tax regulations in Sec. 1.167(l) define a prorated schedule for the extent average accumulated deferred income taxes (ADIT) can be used to reduce rate base to comply with the tax normalization requirements of the tax code when forecast information is used to set rates. Given that the Company's MYRP filing utilizes forecast test year and plan year data, this condition applies. This has been supported by a number of Private Letter Rulings (PLRs) issued by the IRS. In addition, FERC approved the proration logic included in the Company's Attachment O-NSP transmission formula rate of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff in Docket No. ER18-2322-000.

This secondary calculation limits the ADIT deduction from rate base by applying the IRS defined prorate method to only the forecast entries to this balance.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 6, row 84, column 36 with this testimony.

2. Bad Debt

Q. WHAT ADJUSTMENT IS THE COMPANY MAKING RELATED TO BAD DEBT?

A. The Company is making an adjustment to update the bad debt expense for the 2025 test year and 2026 plan year to reflect the rebuttal adjustments to the revenue requirement deficiency. Bad debt expense is a function of projected revenues multiplied by the bad debt ratio for NSPM. Due to the adjustments to the revenue requirement deficiency discussed in my Rebuttal Testimony, an adjustment to bad debt expense is needed to incorporate into the revenue requirement the updated bad debt amount.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 6, row 84, column 37 with this testimony.

3. *Cash Working Capital (CWC)*

Q. DID INTERVENORS RECOMMEND ANY ADJUSTMENT TO CWC FOR THE TEST YEAR?

A. No.

Q. WHAT ADJUSTMENT IS THE COMPANY MAKING IN REBUTTAL FOR CWC?

A. The final level of CWC to be included in this proceeding is a function of the final Commission-approved revenue, expenses, and tax calculations. This calculation will need to be revised after the Commission determines the final revenue requirement as these decisions will impact the level of CWC. Once the final adjustments have been ordered, the Company will recalculate the CWC level to be included in final rates. The calculation of the final CWC level is historically performed as part of a compliance filing proposing final rates.

This adjustment reflects the current adjustments agreed to or proposed by and Company and impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 6, row 84, column 38 with this testimony.

4. Net Operating Loss

Q. PLEASE DESCRIBE THE COMPANY'S NET OPERATING LOSS POSITION AND DEFERRED TAX CREDITS IN THIS CASE.

A. As noted in my Direct Testimony, any change in the revenues, expenses, or capital structure will cause the income tax calculation to change. This could, in turn, affect the timing of the Deferred Tax Assets (DTAs) being generated or utilized and added to or removed from rate base. In addition, any changes in the timing or the amount of tax credits generated or sold (including all forms of PTCs) could also impact the DTAs being generated or utilized. This includes PTCs associated with our nuclear units.

Updating the level of DTAs for rebuttal adjustments impacts the MYRP Forecast revenue requirements by the amounts shown on Schedules 3A and 3B, page 6, row 84, column 39 with this testimony.

The final level of DTAs to be included in this proceeding is a function of the final Commission approved revenues, expenses, tax credits and capital structure. After the Commission decides these issues, the DTA secondary calculation can be finalized. The calculation of the final DTA level is historically performed as part of a compliance filing proposing final rates.

5. Interest Synchronization

Q. DID INTERVENORS RECOMMEND ANY ADJUSTMENT TO INTEREST SYNCHRONIZATION FOR THE TEST YEAR?

A. No.

Q. WHAT ADJUSTMENT IS THE COMPANY MAKING FOR INTEREST SYNCHRONIZATION?

A. The final level of interest synchronization to be included in this proceeding is a function of the final Commission approved rate base, the final approved debt/equity capitalization ratio, and the approved weighted cost of debt. After the Commission rules on these issues, the interest synchronization calculation can be finalized. The calculation of the final interest synchronization level is historically performed as part of a compliance filing proposing final rates.

C. Impacts to Revenue Deficiency

Q. HOW DOES THE COMPANY'S REBUTTAL REVENUE DEFICIENCY COMPARE TO THE REVENUE DEFICIENCY IDENTIFIED IN SUPPLEMENTAL DIRECT TESTIMONY?

A. These updates and amendments decrease our 2025 and 2026 revenue deficiencies, as illustrated by Table X below:

Table 1
2025-2026 Revenue Requests Cumulative
Minnesota Jurisdictional Deficiency Net of Interchange ($s in millions)

MYRP Year	Supplemental Direct	Rebuttal	Percent Reduction
2025	$344.3	$208.4	39%
2026	$473.6	$365.3	23%

III. INTERVENOR ADJUSTMENTS OPPOSED

A. Rate Base Adjustments

1. Sherco 3 Restoration Costs

Q. WHAT WAS INCLUDED IN THE COMPANY'S INITIAL FILING RELATING TO SHERCO 3 RESTORATION COSTS?

A. The Company included utility plant in service for restoration costs resulting from the Sherco 3 turbine catastrophic event on November 19, 2011, in the 2025 test year and 2026 plan year. The original $5.5 million of plant restoration costs not covered by insurance has been depreciated over the last 14 years and has been included in base rates throughout that time. The base rate recovery was initially approved in the Company's 2013 rate case (Docket No. E002/GR-13-868). Of the initial $5.5 million of utility plant in service, approximately $2.4 million of average net utility plant remains in the 2025 test year, and approximately $2.1 million of average net utility plant remains in the 2026 plan year. This information was provided in response to OAG IR No. 1014, provided as Schedule SL-D-10 to OAG witness Shoua Lee's Direct Testimony.[15]

Q. WHAT HAVE INTERVENORS PROPOSED IN RELATION TO SHERCO 3 RESTORATION COSTS?

A. OAG witness Lee suggests that as a result of the 2022 contested case proceeding regarding Sherco 3 costs, restoration costs should not continue to be recovered from customers and instead should be excluded from the MYRP rate base. This recommendation would result in reduction to the Company's

[15] Ex. OAG-___ at Schedule 10 (SL-D-10) (Lee Direct Schedules).

revenue requirements of approximately $0.4 million in the 2025 test year and approximately $0.4 million in the 2026 plan year.[16]

Q. DOES THE COMPANY AGREE WITH THIS ADJUSTMENT?

A. No. As discussed further in the Rebuttal Testimony of Company witness Amy A. Liberkowski, the Commission authorized the Company to include the Sherco Unit 3 restoration costs in excess of insurance reimbursements in rate base in the Company's prior rate case proceedings.[17] The Commission has already determined that the restoration costs at issue are appropriately recoverable in rates, having previously authorized their inclusion in rate base. These depreciation costs remain subject to recovery consistent with the methodology the Commission established at the time. To now disallow recovery of the unamortized balance of Sherco 3 restoration costs, which are not the subject of the contested case proceeding to which OAG witness Lee refers, would amount to undoing a prior regulatory determination and retroactively changing the terms under which those costs were authorized. Accordingly, the continued recovery of restoration costs in rate base is not a new authorization but the ongoing implementation of a prior decision.

2. *Wildfire Mitigation*

Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO DISTRIBUTION WILDFIRE MITIGATION COSTS IN THIS CASE?

A. As discussed in the Direct Testimony of Company witness Mensen and in the Supplemental Direct Testimony of Company witness Bloch, the Company

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[16] Ex. OAG-___ at 24-25 (Lee Direct).

[17] *See In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E002/GR-13-868, Order Reopening, Clarifying, and Supplementing May 8, 2015 Order (Aug. 31, 2015) (requiring that Xcel include Sherco 3 insurance proceeds as an offset to its rate base).

proposed to include Distribution capital investments and O&M expenses related to the Company's wildfire mitigation program in the 2025 test year and 2026 plan year.

Q. WHAT ADJUSTMENTS DID THE DEPARTMENT PROPOSE RELATED TO DISTRIBUTION'S WILDFIRE MITIGATION COSTS?

A. Department witness Eric Borden recommended adjustments to remove a portion of the capital and O&M costs in Distribution's proposed wildfire mitigation budgets for the 2025 test year and the 2026 plan year. Department witness Borden also recommends an adjustment related to the Company's site preparation work associated with deployment of wildfire mitigation programs.

Q. DOES THE COMPANY AGREE WITH THESE RECOMMENDATIONS?

A. No. The Rebuttal Testimony of Company witnesses Bloch and Paul J. McGregor provide the Company's response opposing the recommended adjustments to Distribution's wildfire mitigation capital and O&M budgets, and the Rebuttal Testimony of Company witness Moeller addresses the accounting policy associated with the Company's proposed budgets. The Rebuttal revenue requirement in all schedules provided with this testimony does not include the Department's recommended adjustments.

Q. APART FROM THE CONCEPTUAL DISAGREEMENT, DOES THE COMPANY AGREE WITH THE DEPARTMENT'S CALCULATION OF ITS ADJUSTMENT?

A. No. The basis for the Department's recommended adjustment to Distribution's capital costs is not consistent with the capital costs included in the Supplemental Direct Testimony of Company witness Bloch. Department witness Borden's recommendation would reduce Distribution's capital budget by approximately $46.0 million in 2025 and approximately $164.4 million in 2026, but the Department appears to have estimated the revenue requirement impacts. While the Company does not agree with the adjustments as a whole, the corrected amounts of the proposed adjustments are presented in Schedule 4 to my Rebuttal Testimony.

3. Prepaid Pension Asset

Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO THE PREPAID PENSION ASSET?

A. As discussed in the Direct Testimony of Company witness Richard R. Schrubbe, the Company proposed to include the prepaid pension asset in rate base.

Q. WHAT WAS PROPOSED BY INTERVENORS RELATED TO THE PREPAID PENSION ASSET?

A. Department witness Terry M. Myers recommends that the prepaid pension asset should not be included in rate base and thus recommends a reduction to the revenue requirement deficiency for the 2025 test year and the 2026 plan year.

Q. DOES THE COMPANY AGREE WITH THIS RECOMMENDATION?

A. No. The Rebuttal Testimony of Company witness Schrubbe explains and supports why these proposed adjustments are not reasonable. The Rebuttal revenue requirement in all schedules provided with this testimony excludes this reduction.

Q. APART FROM THE CONCEPTUAL DISAGREEMENT, DOES THE COMPANY AGREE WITH THE DEPARTMENT'S CALCULATION OF ITS ADJUSTMENT?

A. No. Department witness Myers' recommended adjustment does not accurately reflect removal of the prepaid pension asset from rate base. While the Company does not agree with the adjustment as a whole, the corrected amounts of the proposed adjustment are presented in Schedule 4 to my Rebuttal Testimony.

4. *Remaining Lives – Rate Base Adjustment*

Q. WHAT DID INTERVENORS RECOMMEND RELATED TO A RATE BASE ADJUSTMENT ASSOCIATED WITH EXTENDING THE REMAINING LIVES OF THE NUCLEAR PLANTS?

A. As noted in Department witness Johnson's Direct Testimony, Department witness Jones recommends an adjustment to rate base for 2025 and 2026 associated with the remaining lives adjustments of the nuclear and coal plants.

Q. DOES THE COMPANY AGREE WITH THE RECOMMENDED RATE BASE ADJUSTMENT?

A. No. The recommended adjustment appears to be related to a return on rate base associated with extending the depreciable lives of the nuclear and coal plants. However, this is already reflected in the depreciation adjustments identified in Section II above. As such, it would not be appropriate to make a separate rate base adjustment related to extending the depreciable lives of the plants. The Rebuttal revenue requirement in all schedules provided with this testimony does not include this adjustment.

B. Income Statement Adjustments

1. Research and Experimentation (R&E) Federal and State Tax Credits

Q. WHAT WAS PROPOSED BY THE COMPANY IN ITS INITIAL FILING RELATING TO FEDERAL AND STATE R&E TAX CREDITS?

A. The Company included federal R&E tax credits in the amount of $4.5 million (Minnesota Electric jurisdiction) in the 2025 test year and the 2026 plan year. The Company also included Minnesota R&E tax credits in the amount of $1.1 million (Minnesota Electric jurisdiction) in the 2025 test year and 2026 plan year.[18] The Company calculated the R&E credit amounts using an adjusted average of the qualified research expenses (QREs) for tax years 2020 through 2022, as described in the Company's response Department IR No. 1195.[19]

Q. WHAT WAS PROPOSED BY INTERVENORS IN RELATION TO R&E TAX CREDITS?

A. Department Witness Uphus agrees with the Company's method of using an adjusted average of QREs but does not agree with the Company's use of the averages from 2020 through 2022 to forecast the 2025 test year and 2026 plan year amounts. Instead, she recommends using an adjusted average of the QREs using the most recent actuals from 2022 and 2023, and an updated forecast for 2024 based on a 3 year average of 2021-2023 actuals, provided by the Company in response Department IR No. 2166.[20] As a result, Department witness Uphus recommends increasing the Company's 2025 and 2026 federal R&E tax credits by $1.0 million and increasing state R&E tax credits by $269,000 in both 2025 and 2026, which would decrease the revenue requirements.[21]

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[18] *See* Ex. Xcel-___, Vol. 4, MYRP Workpapers, III. P8-2 (Other Tax Credits) at 1.
[19] Ex. DOC-___ at Schedule AU-D-1 at 16-40 (Uphus Direct).
[20] Ex. DOC-___ at 13-14 and Schedule AU-D-1 at 45-46 (Uphus Direct).
[21] Ex. DOC-___ at 14 (Uphus Direct).

Q. WHAT RATIONALE DOES THE DEPARTMENT PROVIDE FOR THEIR RECOMMENDATION?

A. Department witness Uphus states that "Using an adjusted average of the qualified research expenses using most recent actuals from 2022 to 2024 to forecast the R&E credits for 2025 and 2026 test years provides a more accurate estimate than using years 2020 to 2022."[22]

Q. DOES THE COMPANY AGREE WITH THIS RECOMMENDATION?

A. No. The Company does not agree with the Department's recommendation to increase the 2025 test year and 2026 plan year federal and state R&E tax credits. The amounts forecasted by the Company continue to reflect a reasonable forecast of credits for the 2025 test year and 2026 plan year.[23]

Further, in response to Department Information Request No. 2166, the Company provided an updated calculation of R&E credits based on a three-year average of 2022 actuals, 2023 actuals, and a 2024 forecast, but explained that "the *2024 forecast is based on a three-year average of 2021-2023*."[24] In other words, the forecast recommended by Department witness Uphus does not use 2024 actuals, but instead results in a higher weighting of 2022 and 2023 actual amounts as compared to 2021 actual amounts. As a result, the Department's recommendation is not reasonable.

The Company developed its forecast of R&E tax credits using actual QREs from tax years 2020 through 2022. This approach is reasonable because it

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[22] Ex. DOC-___ at 15 (Uphus Direct).
[23] *See* Ex. DOC-___ at Schedule AU-D-1 at 17 (Uphus Direct) (Xcel Energy Response to Department Information Request No. 1195).
[24] Ex. DOC-___ at Schedule AU-D-1 at 45 (Uphus Direct).

relies entirely on the Company's most recent IRS-qualified research activity for which complete data is available, making it the most reliable basis for test year forecasting. The Company's estimates capture three years of actual experience, smoothing annual fluctuations while ensuring that the forecast is grounded in real-world spending.

Q. APART FROM THE CONCEPTUAL DISAGREEMENT, DOES THE COMPANY AGREE WITH THE DEPARTMENT'S CALCULATION OF ITS ADJUSTMENT?

A. No. The Department's adjustment is provided on an NSPM total company basis, which needs to be corrected to reflect the Minnesota jurisdictional amount. The corrected amount of the Department's proposed adjustments on a Minnesota jurisdictional basis are approximately \$396,000 for the federal R&E credit and \$98,000 for the state R&E credit. While the Company does not agree with the adjustment as a whole, the corrected amounts for the proposed adjustment are presented in Schedule 4 to my Rebuttal Testimony.

2. State Tax Credits

Q. WHAT WAS PROPOSED BY THE COMPANY IN ITS INITIAL FILING RELATING TO NORTH DAKOTA INVESTMENT TAX CREDITS?

A. As discussed in my Direct Testimony, the Company is required to share non-Minnesota state tax credits with customers on a proportional basis, specifically related to the North Dakota investment tax credits (ITCs) associated with North Dakota-located wind generation. Consistent with the Commission's Order in the Company's last gas rate case, the Company included the North Dakota ITCs in the MYRP forecast.

Q. WHAT WAS PROPOSED BY INTERVENORS IN RELATION TO THE NORTH DAKOTA ITCS?

A. Department witness Uphus recommends use of the updated forecast information provided in response to Department IR No. 1196 (Schedule AU-D-1 at 11-13) as the basis for the North Dakota ITC offset to the 2025 test year and 2026 plan year. This recommendation would result in an increase in the North Dakota ITC forecast for 2025 and 2026, resulting in a decrease to revenue requirements in each year.

Q. DOES THE COMPANY AGREE WITH THIS ADJUSTMENT?

A. No. Department IR No. 1196 does not provide an updated forecast; rather, it just shows the revenue requirement associated with the North Dakota ITC included in the Company's Direct Testimony. As a result, no adjustment is needed, as both the forecasted credit amount and the revenue requirement are unchanged.

3. Rate Case Expenses

Q. WHAT WAS PROPOSED BY THE COMPANY IN ITS INITIAL FILING RELATING TO RATE CASE EXPENSES?

A. As discussed in my Direct Testimony, the Company requested authorization to recover a total of $4.9 million in rate case costs, amortized over the three-year period 2025-2027, consistent with past practice in electric and gas rate cases. The rate case expense budget was developed by first reviewing actual expenses incurred in our last electric rate case. The Company built the 2025-2026 rate case budget based upon a combination of our plans for outside experts, expected regulatory and legal fees, and estimates for administrative costs such as required notices.

Q. WHAT WAS PROPOSED BY INTERVENORS IN RELATION TO RATE CASE EXPENSES?

A. OAG witness Lee recommends that recovery of rate case expenses be split equally between customers and shareholders. This recommendation would result in a decrease to revenue requirements of approximately $0.8 million in the 2025 test year and 2026 plan year.[25]

Q. WHAT IS THE OAG'S RATIONALE FOR RECOMMENDING THAT RATE CASE EXPENSES BE SPLIT EQUALLY BETWEEN SHAREHOLDERS AND CUSTOMERS?

A. The primary basis for OAG witness Lee's recommendation to split rate case expenses between shareholders and customers is her suggestion that shareholders and customers benefit equally from the Company's efforts to increase rates.[26] She also states that the Company choses when to file a rate case, the number and type of external consultants to hire, and what issues to pursue, which determine that amount of rate case expense incurred.[27]

Q. DOES THE COMPANY AGREE WITH THIS RECOMMENDATION?

A. No. Rate case expenses are a necessary cost of doing business for a regulated utility and thus are included in the cost service and recoverable from customers. The formal rate case process is used to set base rates to recover the cost incurred in providing service to our customers. As a regulated utility, the Company is required to go through a full ratemaking proceeding when requesting a change in rates, and the outcome is not predetermined but rather results from a contested case process.

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[25] Ex. OAG-___ at 21-22 (Lee Direct).
[26] Ex. OAG-___ at 21 (Lee Direct).
[27] Ex. OAG-___ at 16-17 (Lee Direct).

Q. HOW DO YOU RESPOND TO OAG WITNESS LEE'S CHARACTERIZATION THAT SHAREHOLDERS BENEFIT FROM THE COMPANY'S RATE CASE PROCEEDINGS AT LEAST AS MUCH AS CUSTOMERS?[28]

A. OAG witness Lee's statement that from a utility investor's perspective, the goal of a rate case is to increase the utility's revenue to maintain or grow dividend levels ignores the fundamental purpose of a rate case. The purpose of a rate-setting proceeding is to further a utility's right to recover prudently incurred costs necessary to provide service, including a fair return on investment. Further, while a reasonable rate of return (ROR) is necessary to attract investors and allow the Company to secure the capital necessary for system investments, rate cases examine all costs and other factors impacting the revenue deficiency and return on equity (ROE) is but one of those factors. Lastly, access to capital is not an end in itself, but rather is required so that the utility can make the significant, ongoing investments in infrastructure necessary to serve customers and maintain its financial stability needed to continue providing essential utility services over the long term.

Q. OAG WITNESS LEE ALSO NOTES OTHER JURISDICTIONS THAT LIMIT RATE CASE EXPENSE RECOVERY. HOW DO YOU RESPOND?

A. While some jurisdictions have adopted policies to limit recovery of rate case expenses, those examples are not controlling or appropriate here. The overwhelming regulatory principle remains that prudent and reasonable rate case expenses are recoverable. To do otherwise would distort cost recovery, reduce the utility's ability to fully support its operational revenue needs, and ultimately harm customers who rely on rates set through a complete and well-supported record.

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[28] Ex. OAG-___ at 17-18 (Lee Direct).

Q. OAG WITNESS LEE ALSO SUGGESTS THAT UTILITIES HAVE NO INCENTIVE TO KEEP RATE CASE EXPENSES LOW, OTHER THAN THE RATEMAKING PROCESS ITSELF. IS THAT ACCURATE?

A. No. As discussed in the Direct Testimony of Company witness Liberkowski, the Company maintains a focus on keeping rates low, working across all areas of the Company to contain costs and manage to overall reasonable budget levels, recognizing that controlling our costs and maintaining efficient operations is beneficial to our customers. The Company must budget for and monitor spending related to rate case costs, just like any other expenses the Company incurs in providing service to customers. Also, it is important to keep in mind that the drivers of rate case expenses are not wholly in the utility's control.

Q. CAN YOU PROVIDE ADDITIONAL DISCUSSION OF HOW FACTORS OUTSIDE OF THE COMPANY'S CONTROL DRIVE RATE CASE EXPENSE?

A. Certain matters are beyond the Company's control and directly impact the amount of rate case expense incurred. These factors include whether or not a rate case is settled or fully litigated; delays in the proceeding schedule to accommodate regulatory processes;[29] the extent of Supplemental Direct Testimony ordered by the Commission; pre-existing requirements from prior case decisions; the number of intervenors; the volume of discovery requests received that must be answered; the volume and nature of intervenor direct, rebuttal, and surrebuttal testimony and the number and complexity of issues raised; the length and breadth of evidentiary hearings; and other parties' requests for reconsideration.

[29] *See* Order Accepting Filing and Suspending Rates (Dec. 30, 2024) (Suspending the proposed rates in this case for ten months and an additional one-hundred eighty (180) days plus the additional five months requested by parties and agreed to by Xcel until July 31, 2026.).

In this case, the factors outside of the Company's control have already contributed significantly to rate case expense. Those factors include:

- The volume and complexity of discovery received. Through October 1, 2025, the Company has responded to over 550 Information Requests, many of which include multiple subparts. During this same time, the Company produced approximately 32,580 pages of responsive information, documents, and materials and over 275 live Excel files.
- The number of intervenors participating in the docket. In this case, there are eight parties who have intervened in the proceeding.
- The volume and nature of intervenor direct and the number and complexity of issues raised. Twenty-four separate witnesses filed intervenor direct testimony in this case.

Q. OAG WITNESS LEE STATES THAT TO HER KNOWLEDGE, UTILITIES DO NOT USE A FORMAL BIDDING PROCESS TO SELECT ATTORNEYS AND EXPERTS.[30] HOW DO YOU RESPOND?

A. OAG witness Lee seems to suggest that without a competitive bidding process, the Company is overpaying for legal and consulting services compared to what it would pay for such services if there were a competitive bidding process; however, she provides no evidence to support that assumption. The firms and consultants we have partnered with bring very specific knowledge, expertise, and skill sets to our cases. Moreover, the Commission has consistently recognized the reasonableness of the

[30] Ex. OAG-___ at 19 (Lee Direct).

Company's outside legal and expert witness expenses despite the lack of unnecessary competitive bidding.

The assumption that competitive bidding always yields the best result and the lowest cost is overly simplistic. Competitive bidding may produce lower costs for fungible products such as commodities, but it is much less effective for professional services. For example, most people do not select a new doctor every time they seek medical care simply because the new doctor may charge slightly lower costs than their current doctor. Instead, they typically continue using the same doctor because that doctor knows the patient's medical history and understands the patient's medical needs, creating immediate efficiencies. Legal services are no different. An attorney who has dealt with and has familiarity with the issues and witnesses in multiple prior cases is more efficient and cost-effective than one who has neither institutional knowledge nor familiarity with the Company and its processes.

Q. OAG WITNESS LEE ALSO SUGGESTED THAT THERE IS A RISK THAT CUSTOMERS WILL BE CHARGED FOR MORE RATE CASE EXPENSES THAN ARE ACTUALLY INCURRED.[31] HOW DOES THE COMPANY RESPOND?

A. Individual actual Company expenses will rise and fall as compared to representative test year amounts, but this does not indicate an "over recovery" during that period. Rather, other costs change as well, and many of those costs increase. Just as our customers face inflationary pressures on goods and services, the Company is similarly exposed to rising costs driven by inflation. Test year expenses inherently include both increases and decreases compared

[31] Ex. OAG-___ at 19-20 (Lee Direct).

the forecasts; some costs rise while others fall, reflecting the natural fluctuations in utility operations.

Further, while any individual forecasted cost might differ from actual expense incurred, there are factors that significantly mitigate the likelihood that customers will be charged more for rate case expense than is actually incurred. First, the Company has proposed to amortize its forecasted rate case expense over three years 2025-2027 rather than the two-year term of the MYRP, a proposal which no party opposes. Applying a three-year amortization to the recovery of rate case expense mitigates the rate impact of this expense by extending recovery over a longer period and beyond the term of the MYRP, reducing the amount recovered annually.

Second, as explained in my Direct Testimony, the Company developed a reasonable forecast of rate case expense for purposes of this rate case based on actual historical rate case expense from the most recent 2022-2024 electric rate case and anticipated costs to be incurred for outside experts, regulatory and legal fees, and administrative costs. Historical costs were adjusted to reflect the circumstances of the current 2025-2026 MYRP.

The Company makes every effort to develop a reasonable forecast of rate case expense, but circumstances beyond the Company's control can and do impact actual expense incurred. For example, actual rate case expense incurred for the 2022-2024 electric rate case exceeded the Company's forecasted rate case expense in that case by approximately $135,000, with the majority of the variance driven by regulatory fees (i.e., not the Company's own costs). Actual regulatory fees exceeded the Company's forecast for that rate case by over

$400,000.[32] As described above, factors such as delays in the proceeding, the volume and complexity of discovery, and the number and complexity of contested issues drive increases to actual rate case expense.

For these reasons, the Company continues to recommend approval of the rate case expense budget of $4.9 million for this case, to be amortized over the three-year period 2025-2027. There is no valid rationale for removing 50 percent of rate case expense from the test year revenue requirement.

4. *Depreciation Expense – Coal Plants*

Q. WHAT DID THE COMPANY PROPOSE IN THIS CASE WITH RESPECT TO THE EARLY RETIREMENT OF SHERCO UNIT 3 AND THE ALLEN S. KING (KING) PLANT?

A. As discussed in my Direct Testimony and the Direct Testimony of Company witness Johnson in this case, the Company proposed no changes to the remaining lives for Sherco Unit 3 and the King plant in this case. Instead, the Company proposed that these facilities continue to be depreciated using their currently approved remaining lives and when the facilities are retired, any remaining net book value (NBV) should be transferred to a regulatory asset and coupled with the Commission-approved weighted average cost of capital (WACC). This approach provides a balanced solution that aligns with state energy policy directives, ensures the Company has the opportunity to recover prudently incurred costs related to these plants, and is consistent with the Commission's established framework for the evaluation of ratemaking treatment for early retiring generating facilities.

[32] *See* the Company's Response to OAG IR No. 1009, included as Exhibit___(BCH-3), Schedule 5 to my Rebuttal Testimony.

The acceleration of retirement dates from June 2037 to December 2028, and December 2034 to December 2030, respectively for these facilities was originally proposed in the Company's 2022 Minnesota Electric Rate Case, Docket No. E002/GR-21-630. In that case, the Commission withheld a decision on depreciation lives of those assets until the issue was separately addressed in Docket No. E002,E015,E017/CI-23-375, Ratemaking Treatment for Early Retiring Generating Facilities Owned by Regulated Electric Utilities, to further investigate depreciation accounting and other ratemaking issues as they relate to the early retirement of electric generating facilities. In this rate case, the Company evaluated asset recovery methods, as described in the Direct Testimony of Company witness Johnson, and the Company's evaluation supports the regulatory asset approach as the most reasonable ratemaking treatment for these facilities. However, as noted by Company witness Johnson, at the time of the initial filing in this case, there had been no Commission decision in Docket No. E002,E015,E017/CI-23-375.

Q. DID INTERVENORS MAKE RECOMMENDATIONS RELATED TO THE REMAINING LIVES OF THE COMPANY'S COAL PLANTS?

A. Yes. Department witness Jones recommends that the Company match the depreciable lives with operating lives for the King and Sherco Unit 3 coal plants as approved in the Company's 2024-2040 IRP. Shortening the depreciation lives of these coal plants would result in an increase to depreciation expense of approximately $58.8 million in 2025 and $55.4 million in 2026.[33]

[33] Ex. DOC-___ at 15-16 (Jones Direct).

Q. DOES THE COMPANY AGREE WITH THIS RECOMMENDATION?

A. Not at this time. As Company witness Moeller also addresses in his Rebuttal Testimony, shortening of the depreciation lives of these coal plants would result in an increase to depreciation expense of approximately $58.8 million in 2025 and $55.4 million in 2026. The size of these impacts supports the Company's proposed regulatory asset treatment, consistent with the Commission's May 14, 2025 ORDER ESTABLISHING FOUR-TIERED APPROACH FOR RATEMAKING TREATMENT OF EARLY RETIRING GENERATING FACILITIES in Docket No. E002,E015,E017/CI-23-375. In that Order, which was issued after we filed this case, the Commission adopted a flexible, case-by-case tiered framework to balance the interests of customers with those of the utility to ensure rates remain just and reasonable while providing the utility a reasonable opportunity to recover prudently incurred costs.[34] As reflected in the Commission's Order:

> Adopting this tiered approach as the guiding framework and applying it on a case-by-case basis will preserve the Commission's ability to ensure that rates remain just and reasonable and appropriately balance the interests of ratepayers and shareholders consistent with applicable legal frameworks, which include achieving policy goals required in Minnesota. By applying this framework to early retirements in rate cases, utilities, other stakeholders, and the Commission will be able to consider the specific circumstances of an early-retiring facility and balance the interests of the utility, ratepayers, and any other relevant factors, including the decisions in depreciation and integrated resource plan dockets, to determine the appropriate ratemaking treatment of the facility.[35]

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[34] *In re Comm. Inquiry into the Ratemaking Treatment for Early Retiring Generating Facilities Owned by Regulated Elec. Utilities,* Docket No. E002, E015, E017/CI-23-375, ORDER ESTABLISHING FOUR-TIERED APPROACH FOR RATEMAKING TREATMENT OF EARLY RETIRING GENERATING FACILITIES at 8 (May 14, 2025).

[35] *Id.* at 7.

Under the four-tiered framework established by the Commission's Order, tier two considers whether accelerated depreciation is appropriate ratemaking treatment for the facility, recognizing accelerated depreciation may not be appropriate when it could result in affordability concerns or significant rate impacts. If the facility is not deemed appropriate for accelerated depreciation, it is evaluated in tier three, which contemplates the creation of a regulatory asset with some type of return. The purpose of tier three is to minimize cost to customers while also allowing utility recovery of prudently invested capital retiring early due to environmental regulation.

Consistent with the Commission's Order, the Company's proposal to establish regulatory assets after the end of the operating lives of these facilities best balances the impacts of the Commission's decision to approve the early retirements of these plants in furtherance of state clean energy policy. Accelerated depreciation would significantly increase the near-term annual revenue requirements primarily due to higher depreciation expenses, resulting in increased costs for customers. If the Company were to include the $58.8 million in additional depreciation under accelerated depreciation expense in the 2025 rebuttal revenue requirement, that would reflect approximately 21 percent of the total 2025 deficiency. Further, the inclusion of accelerated depreciation would increase the 2025 incremental rate increase by approximately 1.6 percent – from the proposed rebuttal increase of 5.8 percent to 7.4 percent. In light of these impacts, the proposed regulatory asset treatment, which would not require this near-term revenue requirement increase, is consistent with the Commission's framework for evaluating the ratemaking treatment of early retirements.

Under the regulatory asset approach, depreciation remains consistent with the previous presumed retirement date, and the remaining plant NBV at retirement is captured in a regulatory asset. This NBV is then recovered over a Commission-approved period following plant retirement, ensuring a balanced and smoothed rate impact for customers during the transition. In contrast to accelerated depreciation, the regulatory asset method mitigates the burden of higher annual depreciation expenses and associated impacts on customer bills during the early years of the transition.

Additionally, implementing accelerated depreciation with final rates in this case, as recommended by the Department, would likely prevent the Company from having the opportunity to fully recover these additional costs in rates, because the accelerated depreciation expense is not included in interim rates.[36] Such a result would not appropriately reflect that the decision to retire these coal plants early was made in support of state clean-energy policy objectives or balance the interests of customers and the Company in accordance with applicable legal frameworks and clean energy policy goals and directives.

Q. DOES THE DEPARTMENT ADDRESS THE COMMISSION'S ORDER REGARDING EARLY RETIREMENT IN DOCKET NO. E002, E015, E017/CI-23-375 IN MAKING THE PROPOSAL TO SHORTEN THE LIVES AND ACCELERATE THE

[36] In an effort to avoid requesting an increase in interim rates in 2026, on October 1, 2025, the Company filed a letter in this docket, proposing that at the conclusion of this proceeding, the Commission compare the interim rate revenues collected in both 2025 and 2026 to the final revenues determined to be just and reasonable for those years in calculating the refund or surcharge to customers. That approach, if approved, could help to mitigate the Company's concerns regarding the recovery of accelerated depreciation expense. As described in the October 1, 2025 letter, the Company's interim revenue deficiency for 2026 exceeds the level of revenues provided in current interim rates. Coupled with the extended timeline of this proceeding, there is substantial risk that, absent an upward adjustment to its interim rate levels for 2026 or approval of the Company's proposal to compute final refunds or surcharges based on interim rate revenues collected in both 2025 and 2026, the Company could be unable to recover its Commission-approved revenue requirement in 2026.

DEPRECIATION EXPENSE RECOVERY FOR SHERCO UNIT 3 AND THE KING PLANT?

A. No, Department witness Jones does not address the Commission's framework for early retirement in making her recommendation to accelerate the depreciation expense recovery for Sherco Unit 3 and the King plant in this case. As discussed above, because accelerated depreciation of these facilities would result in sizable rate impacts, the Company concludes regulatory asset treatment is appropriate and consistent with the Commission's framework established in Docket No. E002, E015, E017/CI-23-375.

5. *Liquidated Damages*

Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO LIQUIDATED DAMAGES IN THIS PROCEEDING?

A. As discussed in the Direct Testimony of Company witness Capra, a forecast for liquidated damages (*i.e.*, the amounts owed to Xcel Energy per the terms of O&M service agreements with the wind service providers, based on availability of the wind facilities) is not included in the 2025 test year and 2026 plan year.

Q. WHAT WAS PROPOSED BY INTERVENORS RELATED TO LIQUIDATED DAMAGES IN THIS PROCEEDING?

A. Department witness Johnson recommends that the Company include the most recent three-year average of liquidated damages (2022-2024) as an estimate of the amount of liquidated damages for 2025 and 2026. Department witness Johnson calculated that this recommendation would reduce Energy

Supply's O&M expenses by approximately $5.0 million in both 2025 and 2026.[37]

Q. DOES THE COMPANY AGREE WITH THIS RECOMMENDATION?

A. No. The Rebuttal Testimony of Company witness Capra provides support for why this proposed adjustment is not reasonable. The Rebuttal revenue requirement in all schedules provided with this testimony exclude this reduction.

Q. APART FROM THE CONCEPTUAL DISAGREEMENT, DOES THE COMPANY AGREE WITH THE DEPARTMENT'S CALCULATION OF ITS ADJUSTMENT?

A. No. As discussed in Company witness Capra's Rebuttal Testimony, the Department calculated the three-year average based on the Company's response to Department IR No. 156.[38] However, after the Department filed its Direct Testimony, the Company discovered that its response to Department IR No. 156 had erroneously included liquidated damage payments for the Cheyenne Ridge Wind Farm, which is located in Colorado and owned by another Xcel Energy operating company. Removing the liquidated damage amounts for the Colorado wind farm reduces the three-year average of liquidated damages from the $5.0 million included in Department witness Johnson's Direct Testimony to approximately $3.4 million. The corrected amounts are presented in Schedule 4 to my Rebuttal Testimony.

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[37] Ex. DOC-___ at 41-42 (Johnson Direct).
[38] Ex. DOC-___, MAJ-D-6 (Johnson Direct).

6. Insurance

Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO INSURANCE COSTS IN THIS CASE?

A. As discussed in the Direct Testimony of Company witness Robert L. Miller, the Company included insurance premium expense budget amounts in the 2025 test year and the 2026 plan year.

Q. WHAT WAS PROPOSED BY INTERVENORS RELATED TO INSURANCE COSTS?

A. Department witness Jones recommends an adjustment to the 2025 test year calculated on the basis of the 2020 to 2024 actual average, and recommends an adjustment to the 2026 plan year amount based on a percentage change from the 2025 amount recommended by the Department.[39]

Q. DOES THE COMPANY AGREE WITH THIS RECOMMENDATION?

A. No. The Rebuttal Testimony of Company witness Miller provides support for why these proposed adjustments are not reasonable. The Rebuttal revenue requirement in all schedules provided with this testimony does not include this reduction.

Q. DEPARTMENT WITNESS JONES ALSO CLAIMS THERE WAS AN ERROR IN THE COMPANY'S RESPONSE TO DEPARTMENT IR NO. 2106[40] IN THE CALCULATION OF 2024 INSURANCE EXPENSE. DO YOU AGREE?

A. No. The Company has met with Department Staff and has provided information to explain this issue, which is included as Exhibit___(BCH-3), Schedule 6 to my Rebuttal Testimony.

[39] Ex. DOC-__ at 25-26 (Jones Direct).
[40] Ex. DOC-___ at HDJ-D-10 (Jones Direct).

7. *Organizational Dues – Edison Electric Institute (EEI)*

Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO EEI DUES?

A. The Company included EEI dues in the 2025 test year and the 2026 plan year, as shown in Volume 4, Section VIII.A2 of Company's initial filing.

Q. WHAT WAS PROPOSED BY INTERVENORS RELATED TO EEI DUES?

A. OAG witness Lee recommends that the Company provide additional information in Rebuttal Testimony to demonstrate the customer benefits of EEI, and that if the Company is unable to provide support for the EEI dues amounts included in 2025 and 2026, she recommends that an amount equal to the dues invoiced in 2025 should be disallowed for recovery. She recommends an adjustment of approximately $2.4 million to both the 2025 test year and 2026 plan year based on the EEI invoices provided by the Company in response to OAG IR No. 1005.[41]

Q. DOES THE COMPANY AGREE WITH THIS RECOMMENDATION?

A. No. The Rebuttal Testimony of Company witness Robinson provides support for why these proposed adjustments are not reasonable. The Rebuttal revenue requirement in all schedules provided with this testimony does not include this reduction.

Q. APART FROM THE CONCEPTUAL DISAGREEMENT, DOES THE COMPANY AGREE WITH THE DEPARTMENT'S CALCULATION OF ITS ADJUSTMENT?

A. No. As acknowledged in the OAG's response to the Company's IR No. 45, OAG witness Lee's recommended adjustment is equal to the total EEI dues

[41] Ex. OAG-___ at 7 (Lee Direct); Ex. OAG-___ at Schedule 2 (SL-D-2) (Lee Direct Schedules).

invoiced to the Company in 2025.[42] However, these amounts do not represent the Minnesota jurisdictional amount included in the 2025 test year and 2026 plan year, which is approximately $677,000. EEI dues are invoiced to Xcel Energy and then allocated to the operating companies and jurisdiction as noted in Table 2 below. The Rebuttal Testimony of Company witness Robinson clarifies the dues amounts included in the 2025 test year and 2026 plan year are exclusive of any lobbying portion or tax-deductible contributions made to the Edison Foundation (a 501(c)(3) organization affiliated with EEI).

Table 2
Edison Electric Institute Dues

	2025 Total EEI Dues Invoice (Xcel Energy)	$2,350,561
minus	2025 EEI Non-Dues [1]	(438,545)
equals	2025 EEI Dues (Xcel Energy)	$ 1,912,016
multiplied by	Corporate Allocator	43.6843%
equals	Northern States Power Company - Minnesota	$835,251
multiplied by	Electric Utility Allocator	92.96%
multiplied by	MN E Customer Jurisdictional Allocator	87.16%
equals	Minnesota Electric Amount of EEI Dues	$676,761

8. *Employee Recognition Awards*

Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO EMPLOYEE RECOGNITION AWARDS?

A. As discussed in the Direct Testimony of Company witness Robinson, the Company included costs associated with employee recognition awards (*e.g.*,

[42] The OAG's response to Xcel Energy's IR No. 45 is included as Exhibit___(BCH-3), Schedule 7 to my Rebuttal Testimony.

performance-based and safety recognition) in the 2025 test year and 2026 plan year.

Q. WHAT WAS PROPOSED BY INTERVENORS RELATED TO EMPLOYEE AWARDS AND GIFTS?

A. OAG witness Lee recommends that costs related to employee recognition awards that are not safety related should be removed from the 2025 test year and 2026 plan year. She recommends an adjustment of approximately $1.0 million based on actual costs incurred for recognition awards in 2023 that were not safety related.[43]

Q. DOES THE COMPANY AGREE WITH THIS RECOMMENDATION?

A. No. The Rebuttal Testimony of Company witnesses Robinson and Yen Ly provides support for why these proposed adjustments are not reasonable. The Rebuttal revenue requirement in all schedules provided with this testimony does not include this reduction.

Q. APART FROM THE CONCEPTUAL DISAGREEMENT, DOES THE COMPANY AGREE WITH THE OAG'S CALCULATION OF ITS ADJUSTMENT?

A. No. OAG witness Lee's recommended adjustment does not reflect the amount for non-safety-related employee recognition awards that the Company included in the 2025 test and 2026 plan year. As discussed in the Rebuttal Testimony of Company witness Robinson, the Company is requesting recovery for budgeted program costs in the amount of $741,047 for the 2025 test year and $772,320 for the 2026 plan year, and these amounts were reflected in EER Summary Report 1 (providing the budgeted employee

[43] Ex. OAG-___ at 12 (Lee Direct).

expenses for 2025) and EER Summary Report 2 (providing the budgeted employee expenses for 2026).[44] While the Company does not agree with the OAG's recommended adjustment as a whole, the corrected amounts of the proposed adjustment are presented in Schedule 4 to my Rebuttal Testimony.

C. Allocations – Interchange Agreement Allocator

Q. HOW DID THE COMPANY TREAT THE INTERCHANGE AGREEMENT ALLOCATORS IN ITS INITIAL FILING?

A. As discussed in my Direct Testimony, the MYRP Forecast Interchange Revenue and Interchange Expenses were calculated using 2025-2026 Company and Northern States Power Company-Wisconsin (NSPW) budget information. This is consistent with the treatment of Interchange Revenues and Interchange Expenses the Company proposed in our last several rate cases. In my Supplemental Direct Testimony, I noted that the Company had discovered an error in the presentation of interchange revenue and expense in Direct Testimony and provided a corrected interchange agreement demand allocator calculation and updated the proposed revenue requirement.

Q. WHAT DID INTERVENORS PROPOSE WITH RESPECT TO THE INTERCHANGE AGREEMENT ALLOCATORS?

A. Department witness Johnson agreed with the Company's proposed interchange agreement demand allocator but recommends the Commission require the Company to update it interchange allocators for its 2025 test year and 2026 plan year to reflect the Company's 2025 Interchange Agreement approved by FERC on May 6, 2025, as provided in the Company's response to Department IR No. 1160 (Schedule MAJ-D-4). This recommendation

[44] EER Summary Report 1 and 2 were filed in Initial Filing, Vol. 3, 5 of 5 Required Information.

would increase the 2025 revenue deficiency by approximately $273,000 and decreases the 2026 revenue deficiency by approximately $2.9 million.[45]

Q. DOES THE COMPANY AGREE WITH THIS PROPOSAL?

A. No. While the Company agrees the final approved demand allocation for the Interchange Agreement is different than our filed cost of service, that is only one component of the Interchange Agreement billings with NSPW. It is not appropriate to selectively change one of the components. In addition, the proposed adjustment is only applicable to 2025; even if it were to be made in 2025 it should not carry forward to 2026. As explained in response to Department IR No. 1160, application of the 2025 Interchange Agreement demand allocator to 2026 is not representative of the 2026 plan year cost of service and therefore would not be an appropriate basis for the calculation of 2026 plan year costs and revenues. Therefore, it is not appropriate to make a rebuttal adjustment related to the Department's recommendation.

D. Other Intervenor Adjustments Opposed

Q. ARE THERE OTHER ADJUSTMENTS RECOMMENDED BY INTERVENORS THAT THE COMPANY OPPOSES?

A. Yes. All other intervenor recommendations that I do not address in my Rebuttal Testimony are not accepted by the Company, and the Company's responses to those recommendations are addressed by other Company witnesses in Rebuttal Testimony. For convenience, Table 3 below provides a list of all other intervenor recommended adjustments that the Company does not accept and indicates which Company witness responds to each.

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[45] Ex. DOC-___ at 33 (Johnson Direct).

Table 3
Other Intervenor Recommendations

Issue	Intervenor (Witness Making Recommendation)	Company Witness Responding
Distribution Vegetation Management	Department (Uphus)	Mensen
Base Pay Expense	Department (Kehrwald)	Ly
Long-Term Incentive Compensation	Department (Kehrwald) XLI (LaConte)	Ly
Annual Incentive Program	Department (Kehrwald) XLI (LaConte)	Ly
Executive Compensation	Department (Kehrwald)	Ly Mustich
Miscellaneous Benefits, Life Insurance, LTD Expense	Department (Kehrwald)	Schrubbe
Limited Availability Perks Expense	Department (Kehrwald)	Ly
Board of Directors Expense	Department (Kehrwald)	Ly
Transmission O&M Expense	Department (Golden)	Berklund
Outside Services	Department (Golden)	Robinson
General Allocator	Department (Johnson)	Doyle
Liquidated Damages	Department (Johnson)	Capra
Wildfire Allocations from XES	Department (Johnson) OAG (Lee)	Doyle
Riverside Generating Unit	Department (Johnson)	Detmer Liberkowski
Depreciation Expense – Coal Plants	Department (Jones)	Moeller
Property Tax Expense	Department (Jones)	Kowalowski
Non-Qualified Pension Expense	Department (Kehrwald)	Schrubbe
Insurance	Department (Jones)	Miller
Bad Debt Expense	Department (Jones)	Lindgren
Prepaid Pension Asset	Department (Myers)	Schrubbe
Reconnection Fees	CUB (Levenson-Falk)	Martin
Late Payment Revenue	CUB (Levenson-Falk)	Martin
Distribution Capacity Investments	Joint Intervenors (Kenworthy)	Mensen
Distribution Communications Infrastructure	Joint Intervenors (Kenworthy)	Mensen

Association Dues (EEI)	OAG (Lee)	Robinson
Chamber of Commerce Dues	OAG (Lee)	Robinson
Employee Awards and Gifts	OAG (Lee)	Robinson Ly
Investor Relations	OAG (Lee)	Wehner
Distribution Targeted Undergrounding	OAG (Lee) Joint Intervenors (Kenworthy)	Mensen
Energy Supply O&M	XLI (LaConte)	Capra
Transmission O&M	XLI (LaConte)	Berklund
Customer Care O&M	XLI (LaConte)	Lindgren
Wildfire Mitigation	Department (Borden) Joint Intervenors (Kenworthy)	McGregor Bloch

IV. TRACKERS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my Rebuttal Testimony, I summarize the Company's proposed trackers and deferrals in this case. These mechanisms will track and either recover or return to customers certain actual revenues, credits, and costs that are highly variable, significant, and outside the Company's control. I also summarize intervenor recommendations related to the Company's proposed trackers.

Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO TRACKER AND DEFERRALS IN THIS CASE?

A. As I discussed in my Direct Testimony, the Company proposed to continue the sales true-up, capital true-up, wind and solar PTCs tracker, capacity revenue and expense tracker, and property tax true-up, each of which was approved in a prior Company rate case or related filing. To manage other highly variable circumstances facing the Company and our customers, the

Company also proposed new tracker treatment for nitrogen oxide (NOx) allowances, coal combustion residuals (CCR), and bad debt expense. As summarized below, intervenors either explicitly agreed with the Company's proposals, or did not express any concerns with continuing or implementing the trackers as proposed by the Company.

Q. DID INTERVENORS PROVIDE TESTIMONY RELATED TO THE SALES TRUE-UP?

A. Yes. Department witness Bahn indicates he has no major concerns with the Company's proposal to continue its sales true-up but requests that the Company confirm there are no changes from what was proposed in the last MYRP.[46]

Q. HOW DOES THE COMPANY RESPOND?

A. The Company appreciates the Department's support for continuing the sales true-up. Company witness Paluck confirms in his Rebuttal Testimony that the proposal in this case is identical to the sales true-up that was approved in the Company's last electric rate case.

Q. DID INTERVENORS PROVIDE TESTIMONY RELATED TO THE CAPITAL TRUE-UP?

A. Yes. Department witness Johnson indicates that the Company's proposal appears consistent with the Company's previous capital true-up as approved by the Commission in the Company's last electric rate case and recommends approval of the Company's proposal to continue its capital true-up for the 2025 and 2026 test years.[47]

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[46] Ex. DOC-___ at 17 (Bahn Direct).
[47] Ex. DOC-___ at 52, 56 (Johnson Direct).

Q. DID INTERVENORS PROVIDE TESTIMONY RELATED TO THE WIND AND SOLAR PTCS TRUE-UP?

A. Yes. Department witness Uphus agrees with the Company's proposal to continue to use a true-up mechanism for PTCs in the RES Rider.[48]

Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO CAPACITY REVENUES AND EXPENSES?

A. As noted above, the Company proposes to carry capacity revenues and expenses in a tracker, similar to the capacity revenue tracker implemented in the Company's last electric rate case, and proposed a baseline revenue amount in base rates.[49]

Q. DID INTERVENORS PROVIDE TESTIMONY RELATED TO THE CAPACITY REVENUE TRACKER?

A. Yes. A discussed in Section II above, Department witness Golden recommends the Company update the baseline capacity revenue amounts in the 2025 test year and 2026 plan year and agrees that these amounts will be subject to true-up in the Company's annual capacity tracker filings.[50]

Q. HOW DOES THE COMPANY RESPOND?

A. As discussed in Section II above, the Company agrees with the recommended adjustment to the baseline amounts in 2025 and 2026, and the Company appreciates Department witness Golden's recommendation for approval of continuing the capacity revenue tracker for annual true-up of the capacity revenues. The Company continues to request approval to continue to carry

[48] Ex. DOC-___ at 6 (Uphus Direct).
[49] Ex. Xcel-___ at 78 (Halama Direct).
[50] Ex. DOC-___ at 13-14 (Golden Direct).

capacity revenues and expenses in a tracker similar to the tracker implemented in the Company's last electric rate case.

Q. DID INTERVENORS PROVIDE TESTIMONY RELATED TO THE PROPERTY TAX TRUE-UP?

A. Yes. Department witness Jones recommends continuing the property tax true-up but proposes a five percent cap allowing the Company to recover amounts up to five percent above the Commission-approved amount to be included in the MYRP.[51]

Q. HOW DOES THE COMPANY RESPOND?

A. The Company appreciates the Department's recommendation for continuing the property tax true-up, but the Company does not agree with the proposed five percent cap. The Rebuttal Testimony of Company witness William T. Kowalowski provides support for why the proposed five percent cap is not reasonable.

Q. DID INTERVENORS PROVIDE TESTIMONY RELATED TO THE COMPANY'S PROPOSED TRACKER FOR COSTS ASSOCIATED WITH COMPLIANCE WITH THE GOOD NEIGHBOR PLAN (GNP) DESIGNED TO LIMIT NOX EMISSIONS?

A. Yes. Department witness Golden recommends the Commission approve the Company's proposal to recover any potential costs related to NOx allowances through a tracker mechanism. He also recommends the Company be required to provide adequate support for their NOx allowances and/or generation

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[51] Ex. DOC-___ at 13 (Jones Direct).

curtailment expenses in their annual compliance filings to support recovery of these costs.[52]

Q. HOW DOES THE COMPANY RESPOND?

A. The Company appreciates the Department's recommendation for approval of the NOx true-up mechanism. The Rebuttal Testimony of Company witness Jeffrey L. West responds to the recommendations for information to be included in future filings.

Q. DID INTERVENORS PROVIDE TESTIMONY RELATED TO THE COMPANY'S PROPOSED TRACKER FOR COSTS ASSOCIATED WITH INVESTIGATION AND REMEDIATION OF CCR SITES?

A. Yes. Department witness Golden also recommends approval of the Company's tracker proposal related to management of the Company's CCR sites. He also recommends that adequate support for any costs included in the tracker be provided in annual compliance filings, and he recommends that the Company not be allowed to include any internal labor costs in the tracker.[53]

Q. HOW DOES THE COMPANY RESPOND?

A. The Company appreciates the Department's recommendation for approval of the CCR true-up mechanism. The Rebuttal Testimony of Company witness West responds to the recommendations for information to be included in future filings and that internal labor costs not be included in the tracker.

[52] Ex. DOC-___ at 21 (Golden Direct).
[53] Ex. DOC-___ at 26 (Golden Direct).

Q. DID INTERVENORS PROVIDE TESTIMONY RELATED TO THE COMPANY'S PROPOSED TRACKER FOR COSTS ASSOCIATED WITH INVESTIGATION AND REMEDIATION OF CCR SITES?

A. Yes. CUB witness Levenson-Falk agrees that it is in customers' interest to track and true-up bad debt expense and recommends approval of the Company's proposed bad debt tracker.[54] ECC witness George Shardlow also supports the Company's bad debt tracker proposal.[55]

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. I recommend that the Commission determine a revenue deficiency for each year of the MYRP as follows:

Table 4
2025-2026 Revenue Requests
Minnesota Jurisdictional Deficiency Net of Interchange ($s in millions)

MYRP Year	2025	2026
Amount, cumulative	$208.4	$365.3
Amount, incremental	$208.4	$156.9
Average % increase, incremental *	5.8%	4.2%

I also recommend approval of the associated treatment of the Company's riders and secondary calculations. Lastly, I recommend approval of the Company's proposed trackers, as set forth in my Direct and Rebuttal Testimony.

[54] Ex. CUB-___ at 25 (Levenson-Falk Direct).
[55] Ex. ECC-___ at 14-15 (Shardlow Direct).

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

Northern States Power Company
State of Minnesota Electric Jurisdiction

SUMMARY OF REVENUE REQUIREMENTS
($000's)

Line	Description	Adjusted Rebuttal Test Year 2025	Adjusted Rebuttal Plan Year 2026
1	Average Rate Base	$13,424,971	$14,325,769
2	Operating Income (Before AFUDC)	$784,769	$735,838
3	Allowance for Funds Used During Construction	$81,643	$85,431
4	Total Available for Return (Line 2 + Line 3 + Rounding)	$866,412	$821,269
5	Overall Rate of Return (Line 4 / Line 1)	6.45%	5.73%
6	Required Rate of Return	7.56%	7.55%
7	Operating Income Requirement (Line 1 x Line 6)	$1,014,928	$1,081,596
8	Income Deficiency (Line 7 - Line 4)	$148,516	$260,326
9	Gross Revenue Conversion Factor	1.40335	1.40335
10	Revenue Deficiency (Line 8 x Line 9)	$208,420	$365,329
11	Retail Related Revenue Under Present Rates	$3,575,050	$3,631,344
12	Percentage Increase Needed in Overall Revenue (Line 10 / Line 11)	5.83%	10.06%
13	Retail Related Revenue Under Present Rates EXCLUDING FUEL	$2,758,341	$2,799,787
14	Percentage Increase Needed Excluding Fuel (Line 10 / Line 13)	7.56%	13.05%

COST OF SERVICE SUMMARY for 2025-2026 MYRP FORECAST ($000's)

Line No.		Minnesota Electric Jurisdiction 2025 Test Year	Minnesota Electric Jurisdiction 2026 Plan Year
1	**Composite Income Tax Rate**		
2	State Tax Rate	9.80%	9.80%
3	Federal Statuatory Tax Rate	21.00%	21.00%
4	Federal Effective Tax Rate	18.94%	18.94%
5	**Composite Tax Rate**	**28.74%**	**28.74%**
6	Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.403351	1.403351
7			
8	**Weighted Cost of Capital**		
9	Active Rates and Ratios Version	Proposed	Proposed
10	Cost of Short Term Debt	5.31%	3.38%
11	Cost of Long Term Debt	4.51%	4.53%
12	Cost of Common Equity	10.30%	10.30%
13	Ratio of Short Term Debt	0.79%	1.00%
14	Ratio of Long Term Debt	46.71%	46.50%
15	Ratio of Common Equity	52.50%	52.50%
16	Weighted Cost of STD	0.04%	0.03%
17	Weighted Cost of LTD	2.11%	2.11%
18	Weighted Cost of Debt	2.15%	2.14%
19	Weighted Cost of Equity	5.41%	5.41%
20	**Required Rate of Return**	**7.56%**	**7.55%**
21			
22	**Rate Base**		
23	Plant Investment	25,953,798	27,321,625
24	Depreciation Reserve	11,762,893	12,181,173
25	Net Utility Plant	14,190,905	15,140,451
26	CWIP	987,743	1,099,022
27			
28	Accumulated Deferred Taxes	2,955,244	3,029,670
29	DTA - NOL Average Balance	(27,352)	(16,944)
31	DTA - Federal Tax Credit Average Balance	(791,474)	(734,130)
32	Total Accum Deferred Taxes	2,133,307	2,274,724
33			
34	Cash Working Capital	(87,580)	(97,005)
35	Materials and Supplies	185,838	185,838
36	Fuel Inventory	85,634	85,634
37	Non-plant Assets and Liabilities	97,601	99,107
38	Customer Advances	(11,597)	(11,597)
39	Customer Deposits	(31,601)	(31,601)
40	Prepaids and Other	79,750	76,432
41	Regulatory Amortizations	61,585	54,211
42	Total Other Rate Base Items	379,631	361,020
43			
44	**Total Rate Base**	**13,424,971**	**14,325,769**
45			

COST OF SERVICE SUMMARY for 2025-2026 MYRP FORECAST ($000's)

Line No.		Minnesota Electric Jurisdiction	
		2025 Test Year	2026 Plan Year
46	**Operating Revenues**		
47	Retail	3,574,738	3,630,853
48	Interdepartmental	312	491
49	Other Operating Rev - Non-Retail	887,115	878,749
50	**Total Operating Revenues**	**4,462,165**	**4,510,093**
51			
52	**Expenses**		
53	Operating Expenses:		
54	Fuel	1,293,647	1,277,326
55	Deferred Fuel	5,114	4,840
56	Variable IA Production Fuel	10,544	10,614
57	Purchased Energy - Windsource	0	0
58	Fuel & Purchased Energy Total	1,309,305	1,292,781
59	Production - Fixed	444,803	445,297
60	Production - Fixed IA Investment		
61	Production - Fixed IA O&M	48,456	78,742
62	Production - Variable	3,087	3,170
63	Production - Variable IA O&M	6,283	6,379
64	Production - Purchased Demand	123,593	109,312
65	Production Total	626,223	642,900
66	Regional Markets	9,862	10,356
67	Transmission IA	139,441	144,037
68	Transmission	142,371	146,934
69	Distribution	114,531	116,789
70	Customer Accounting	51,362	60,588
71	Customer Service & Information	168,895	174,543
72	Sales, Econ Dvlp & Other	10,409	8,608
73	Administrative & General	290,783	300,842
74	**Total Operating Expenses**	**2,863,181**	**2,898,379**
75			
76	Depreciation	792,136	806,888
77	Amortization	44,939	54,152
78			
79	**Taxes:**		
80	Property Taxes	181,068	191,009
81	ITC Amortization	24,932	(1,478)
82	Deferred Taxes	69,759	77,303
83	Deferred Taxes - NOL	11,407	9,547
84	Less State Tax Credits deferred	(693)	(830)
85	Less Federal Tax Credits deferred	(329,072)	(305,800)
86	Deferred Income Tax & ITC	(223,667)	(221,259)
87	Payroll & Other Taxes	28,109	29,174
88	**Total Taxes Other Than Income**	**(14,490)**	**(1,077)**
89			

COST OF SERVICE SUMMARY for 2025-2026 MYRP FORECAST ($000's)

Line No.		Minnesota Electric Jurisdiction 2025 Test Year	2026 Plan Year
90	**Income Before Taxes**		
91	Total Operating Revenues	4,462,165	4,510,093
92	less: Total Operating Expenses	2,863,181	2,898,379
93	Book Depreciation	792,136	806,888
94	Amortization	44,939	54,152
95	Taxes Other than Income	(14,490)	(1,077)
96	**Total Before Tax Book Income**	776,398	751,750
97			
98	**Tax Additions**		
99	Book Depreciation	792,136	806,888
100	Deferred Income Taxes and ITC	(223,667)	(221,259)
101	Nuclear Fuel Burn (ex. D&D)	107,328	113,579
102	Nuclear Outage Accounting	53,341	46,357
103	Avoided Tax Interest	40,937	49,143
104	Other Book Additions	5,541	5,541
105	**Total Tax Additions**	775,617	800,249
106			
107	**Tax Deductions**		
108	Total Rate Base	13,424,971	14,325,769
109	Weighted Cost of Debt	2.15%	2.14%
110	Debt Interest Expense	288,637	306,571
111	Nuclear Outage Accounting	56,132	36,929
112	Tax Depreciation and Removals	1,242,869	1,317,921
113	NOL Utilized / (Generated)	40,691	34,056
114	Other Tax / Book Timing Differences	(15,846)	(25,919)
115	**Total Tax Deductions**	**1,612,483**	**1,669,558**
116			
117	**State Taxes**		
118	State Taxable Income	(60,467)	(117,559)
119	State Income Tax Rate	9.80%	9.80%
120	State Taxes before Credits	(5,926)	(11,521)
121	Less State Tax Credits applied	(748)	(626)
122	**Total State Income Taxes**	(6,674)	(12,147)
123			
124	**Federal Taxes**		
125	Federal Sec 199 Production Deduction		
126	Federal Taxable Income	(53,794)	(105,412)
127	Federal Income Tax Rate	21.00%	21.00%
128	Federal Tax before Credits	(11,297)	(22,137)
129	Less Federal Tax Credits	9,599	50,195
130	**Total Federal Income Taxes**	(1,698)	28,059
131			
132	**Total Taxes**		
133	Total Taxes Other than Income	(14,490)	(1,077)
134	Total Federal and State Income Taxes	(8,371)	15,912
135	**Total Taxes**	(22,861)	14,835
136			
137	**Total Operating Revenues**	**4,462,165**	**4,510,093**
138	**Total Expenses**	**3,677,395**	**3,774,255**
139			
140	AFDC Debt	27,505	29,568
141	AFDC Equity	54,137	55,863
142			
143	**Net Income**	**866,412**	**821,269**

COST OF SERVICE SUMMARY for 2025-2026 MYRP FORECAST ($000's)

Line No.		Minnesota Electric Jurisdiction 2025 Test Year	2026 Plan Year
144			
145	**Rate of Return (ROR)**		
146	Total Operating Income	866,412	821,269
147	Total Rate Base	13,424,971	14,325,769
148	**ROR (Operating Income / Rate Base)**	6.45%	5.73%
149			
150	**Return on Equity (ROE)**		
151	Net Operating Income	866,412	821,269
152	Debt Interest (Rate Base * Weighted Cost of Debt)	(288,637)	(306,571)
153	Earnings Available for Common	577,775	514,698
154	Equity Rate Base (Rate Base * Equity Ratio)	7,048,110	7,521,029
155	**ROE (earnings for Common / Equity)**	8.20%	6.84%
156			
157	**Revenue Deficiency**		
158	Required Operating Income (Rate Base * Required Return)	1,014,928	1,081,596
159	Net Operating Income	866,412	821,269
160	**Operating Income Deficiency**	148,516	260,326
161			
162	Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.403351	1.403351
163	**Revenue Deficiency (Income Deficiency * Conversion Factor)**	**208,420**	**365,329**
164			
165	**Total Revenue Requirements**		
166	Total Retail Revenues	3,575,050	3,631,344
167	Revenue Deficiency	208,420	365,329
168	Total Revenue Requirements	3,783,470	3,996,673
169			
170	**Excluding Fuel Expense and Revenue**		
171	Total Fuel Related Expense	1,037,511	1,033,426
172	Line 138 Less Fuel Related Expense	2,639,884	2,740,829
173			
174	Total Fuel Related Revenue, net of Nuclear PTC Refunds	963,020	973,782
175	Nuclear PTC Refunds (BCH-3 Sch 3A and 3B)	(74,491)	(59,643)
176	Total Fuel Related Revenue excluding Nuclear PTC Refunds	1,037,511	1,033,426
177	Line 137 Less Fuel Related Revenue and Nuclear PTC	3,424,654	3,476,667
178			
179	Revised Net Income (including AFUDC)	866,412	821,269
180	Change due to Excluding Fuel	-	-

2025 Test Year Income Statement Bridge Schedule

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
		Bridge - Supplemental															
Line No.		Supplemental	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Supplemental Direct	CSG Electric Revenue	Customer Advances	Decommissioning	Depreciation Study: TD&G	DI MEC	Distributed Intelligence	Employee Expense	EOL Nuclear Fuel	EV Program	Excess Capacity Proceeds	Hosting
1																	
2	Plant as booked																
3	Production	13,504,788				13,504,788											
4	Transmission	4,258,451				4,258,451											
5	Distribution	5,466,777				5,466,777									482		
6	General	1,465,824				1,465,824					(2,123)	(772)					
7	Common	1,261,218				1,261,218											
8	Total Utility Plant in Service	25,957,059				25,957,059					(2,123)	(772)			482		
9																	
10	Reserve for Depreciation																
11	Production	7,707,920				7,707,920								(422)			
12	Transmission	995,931				995,931											
13	Distribution	1,832,177				1,832,177				(1,988)					19		
14	General	723,085				723,085				(182)	(300)	(64)					
15	Common	554,815				554,815				(212)							
16	Total Reserve for Depreciation	11,813,929				11,813,929				(2,382)	(300)	(64)		(422)	19		
17																	
18	Net Utility Plant																
19	Production	5,796,868				5,796,868								422			
20	Transmission	3,262,520				3,262,520											
21	Distribution	3,634,600				3,634,600				1,988					463		
22	General	742,739				742,739				182	(1,823)	(708)					
23	Common	706,403				706,403				212							
24	Net Utility Plant in Service	14,143,130				14,143,130				2,382	(1,823)	(708)		422	463		
25																	
26	Utility Plant Held for Future Use																
27																	
28	Construction Work in Progress	986,924				986,924									124		
29																	
30	Less: Accumulated Deferred Income Taxes	2,561,372	(1,389)		(297,496)	2,262,486				766	(118)	(55)		118	8		
31																	
32	Other Rate Base Items																
33	Cash Working Capital			(86,894)		(86,894)											
34	Materials and Supplies	185,838				185,838											
35	Fuel Inventory	85,634				85,634											
36	Non Plant Assets and Liabilities	97,601				97,601											
37	Customer Advances	(10,577)				(10,577)		(1,019)									
38	Customer Deposits	(31,601)				(31,601)											
39	Prepayments	79,750				79,750											
40	Regulatory Amortizations	61,585				61,585											
41	Total Other Rate Base	468,230		(86,894)		381,336		(1,019)									
42																	

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
		Bridge - Supplemental															
Line No.		Supplemental	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Supplemental Direct	CSG Electric Revenue	Customer Advances	Decommissioning	Depreciation Study: TD&G	DI MEC	Distributed Intelligence	Employee Expense	EOL Nuclear Fuel	EV Program	Excess Capacity Proceeds	Hosting
43	Total Average Rate Base	13,036,911	1,389	(86,894)	297,496	13,248,903		(1,019)		1,617	(1,705)	(652)		304	580		
44																	
45	Operating Revenues																
46	Retail Revenue	3,665,579				3,665,579											
47	Interdepartmental	485				485											
48	Other Operating	855,480				855,480	742							(131)		38,744	
49	Total Revenue	4,521,543				4,521,543	742							(131)		38,744	
50																	
51	Expenses																
52	Operating Expenses																
53	Fuel & Purchased Energy	1,309,305				1,309,305											
54	Power Production	634,956				634,956								(844)			
55	Transmission	281,812				281,812											
56	Distribution	114,398				114,398									133		
57	Customer Accounting	52,081				52,081											
58	Customer Service and Information	168,895				168,895											
59	Sales, Econ Dev, & Other	10,409				10,409											
60	Administrative and General	290,757				290,757							(24)				
61	Total Operating Expenses	2,862,612				2,862,612							(24)	(844)	133		
62																	
63	Depreciation	914,623				914,623			(21,571)	(4,765)	(322)	(110)			38		
64	Amortization	44,939				44,939											
65																	
66	Taxes																
67	Property	181,068				181,068											
68	Deferred Income Tax and ITC	74,910			(242,263)	(167,353)				1,532	(101)	(37)		237	15		
69	Federal and State Income Tax	(258,095)	(9)	537	240,424	(17,142)	213	6	6,200	(10)	203	72	7	(40)	(67)	11,136	
70	Payroll and Other	28,109				28,109											
71	Total Taxes	25,992	(9)	537	(1,838)	24,682	213	6	6,200	1,522	102	35	7	197	(52)	11,136	
72																	
73	Total Expenses	3,848,165	(9)	537	(1,838)	3,846,855	213	6	(15,371)	(3,243)	(220)	(75)	(17)	(647)	119	11,136	
74																	
75	Allowance for Funds Used During Const	81,615				81,615									12		
76																	
77	Net Income	754,993	9	(537)	1,838	756,303	528	(6)	15,371	3,243	220	75	17	516	(107)	27,608	
78																	
79	Calculation of Revenue Requirements																
80	Rate Base	13,036,911	1,389	(86,894)	297,496	13,248,903		(1,019)		1,617	(1,705)	(652)		304	580		
81	Required Operating Income	985,591	105	(6,569)	22,491	1,001,617		(77)		122	(129)	(49)		23	44		
82	Operating Income	754,993	9	(537)	1,838	756,303	528	(6)	15,371	3,243	220	75	17	516	(107)	27,608	
83	Income Deficiency	230,598	96	(6,032)	20,652	245,314	(528)	(71)	(15,371)	(3,121)	(349)	(125)	(17)	(493)	151	(27,608)	
84	**Revenue Deficiency**	**323,610**	**135**	**(8,465)**	**28,982**	**344,262**	**(742)**	**(99)**	**(21,571)**	**(4,380)**	**(489)**	**(175)**	**(24)**	**(691)**	**212**	**(38,744)**	

2025 Test Year Income Statement Bridge Schedul

(1)	(2)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)	(31)	(32)	(33)	(34)	(35)
		Rebuttal Adjustments																
Line No.		Late Payment	Luverne Battery	Nuclear PTC	Production Tax Credit: Solar	Production Tax Credits	Reconnection Fees	Remaining Life: Hydro	Remaining Life: Nuclear	Remaining Life: Salvage	Rider: TCR FERC Reclass	Rider: TCR Update	Rider: TCR Revenue	Sales Fcst Update	Service Quality	Sherco Inventory	TOU Program	Wildfire Capital
1																		
2	Plant as booked																	
3	Production																	
4	Transmission																	
5	Distribution											(848)						
6	General											(0)						
7	Common																	
8	Total Utility Plant in Service											(848)						
9																		
10	Reserve for Depreciation																	
11	Production		1					778	(43,104)	(2,778)								
12	Transmission																	
13	Distribution											(33)						
14	General							38	(2,789)									
15	Common																	
16	Total Reserve for Depreciation		1					816	(45,893)	(2,778)		(33)						
17																		
18	Net Utility Plant																	
19	Production		(1)					(778)	43,104	2,778								
20	Transmission																	
21	Distribution											(815)						
22	General							(38)	2,789			(0)						
23	Common																	
24	Net Utility Plant in Service		(1)					(816)	45,893	2,778		(815)						
25																		
26	Utility Plant Held for Future Use																	
27																		
28	Construction Work in Progress						405										290	
29																		
30	Less: Accumulated Deferred Income Taxes		(0)				0	(228)	15,257	815		(21)					0	
31																		
32	Other Rate Base Items																	
33	Cash Working Capital																	
34	Materials and Supplies																	
35	Fuel Inventory																	
36	Non Plant Assets and Liabilities																	
37	Customer Advances																	
38	Customer Deposits																	
39	Prepayments																	
40	Regulatory Amortizations																	
41	Total Other Rate Base																	
42																		

(1)	(2)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)	(31)	(32)	(33)	(34)	(35)
		Rebuttal Adjustments																
Line No.		Late Payment	Luverne Battery	Nuclear PTC	Production Tax Credit: Solar	Production Tax Credits	Reconnection Fees	Remaining Life: Hydro	Remaining Life: Nuclear	Remaining Life: Salvage	Rider: TCR FERC Reclass	Rider: TCR Update	Rider: TCR Revenue	Sales Fcst Update	Service Quality	Sherco Inventory	TOU Program	Wildfire Capital
43	Total Average Rate Base		(1)				404	(588)	30,636	1,963		(795)					290	
44																		
45	Operating Revenues																	
46	Retail Revenue			(74,491)								(125)	125	(16,350)				
47	Interdepartmental													(173)				
48	Other Operating	6,110	0					254	(13,234)	(850)								
49	Total Revenue	6,110	0	(74,491)				254	(13,234)	(850)		(125)	125	(16,523)				
50																		
51	Expenses																	
52	Operating Expenses																	
53	Fuel & Purchased Energy																	
54	Power Production															1,973		
55	Transmission																	
56	Distribution																	
57	Customer Accounting																	
58	Customer Service and Information																	
59	Sales, Econ Dev, & Other																	
60	Administrative and General														50			
61	Total Operating Expenses														50	1,973		
62																		
63	Depreciation		2					1,632	(91,786)	(5,556)		(48)						
64	Amortization																	
65																		
66	Taxes																	
67	Property																	
68	Deferred Income Tax and ITC		(1)	2,794	(3)	808	1	(455)	30,550	1,630		(20)					1	
69	Federal and State Income Tax	1,756	0	(77,285)	63	(16,156)	(2)	77	(3,993)	(256)		4	36	(4,749)	(14)	(567)	(2)	
70	Payroll and Other																	
71	Total Taxes	1,756	(1)	(74,491)	60	(15,348)	(2)	(379)	26,557	1,374		(17)	36	(4,749)	(14)	(567)	(1)	
72																		
73	Total Expenses	1,756	2	(74,491)	60	(15,348)	(2)	1,253	(65,229)	(4,182)		(65)	36	(4,749)	36	1,406	(1)	
74																		
75	Allowance for Funds Used During Const						9										7	
76																		
77	Net Income	4,354	(1)	(0)	(60)	15,348	11	(999)	51,994	3,332		(60)	89	(11,774)	(36)	(1,406)	8	
78																		
79	Calculation of Revenue Requirements																	
80	Rate Base		(1)				404	(588)	30,636	1,963		(795)					290	
81	Required Operating Income		(0)				31	(44)	2,316	148		(60)					22	
82	Operating Income	4,354	(1)	(0)	(60)	15,348	11	(999)	51,994	3,332		(60)	89	(11,774)	(36)	(1,406)	8	
83	Income Deficiency	(4,354)	1	0	60	(15,348)	20	955	(49,678)	(3,184)			(89)	11,774	36	1,406	14	
84	**Revenue Deficiency**	**(6,110)**	**2**	**0**	**84**	**(21,538)**	**28**	**1,340**	**(69,716)**	**(4,468)**			**(125)**	**16,523**	**50**	**1,973**	**20**	

2025 Test Year Income Statement Bridge Schedul

(1)	(2)	(36)	(37)	(38)	(39)	(40)
		Secondary Calculations				
Line No.		ADIT Prorate for IRS	Bad Debt Expense	Cash Working Capital	Net Operating Loss	Total
1						
2	Plant as booked					
3	Production					13,504,788
4	Transmission					4,258,451
5	Distribution					5,466,411
6	General					1,462,929
7	Common					1,261,218
8	Total Utility Plant in Service					25,953,798
9						
10	Reserve for Depreciation					
11	Production					7,662,396
12	Transmission					995,931
13	Distribution					1,830,174
14	General					719,789
15	Common					554,603
16	Total Reserve for Depreciation					11,762,893
17						
18	Net Utility Plant					
19	Production					5,842,393
20	Transmission					3,262,520
21	Distribution					3,636,236
22	General					743,140
23	Common					706,615
24	Net Utility Plant in Service					14,190,905
25						
26	Utility Plant Held for Future Use					
27						
28	Construction Work in Progress					987,743
29						
30	Less: Accumulated Deferred Income Taxes	(805)			(144,917)	2,133,307
31						
32	Other Rate Base Items					
33	Cash Working Capital			(686)		(87,580)
34	Materials and Supplies					185,838
35	Fuel Inventory					85,634
36	Non Plant Assets and Liabilities					97,601
37	Customer Advances					(11,597)
38	Customer Deposits					(31,601)
39	Prepayments					79,750
40	Regulatory Amortizations					61,585
41	Total Other Rate Base			(686)		379,631
42						

(1)	(2)	(36)	(37)	(38)	(39)	(40)
		Secondary Calculations				
Line No.		ADIT Prorate for IRS	Bad Debt Expense	Cash Working Capital	Net Operating Loss	Total
43	Total Average Rate Base	805		(686)	144,917	13,424,971
44						
45	Operating Revenues					
46	Retail Revenue					3,574,738
47	Interdepartmental					312
48	Other Operating					887,115
49	Total Revenue					4,462,165
50						
51	Expenses					
52	Operating Expenses					
53	Fuel & Purchased Energy					1,309,305
54	Power Production					636,085
55	Transmission					281,812
56	Distribution					114,531
57	Customer Accounting		(719)			51,362
58	Customer Service and Information					168,895
59	Sales, Econ Dev, & Other					10,409
60	Administrative and General					290,783
61	Total Operating Expenses		(719)			2,863,181
62						
63	Depreciation					792,136
64	Amortization					44,939
65						
66	Taxes					
67	Property					181,068
68	Deferred Income Tax and ITC				(93,263)	(223,667)
69	Federal and State Income Tax	(5)	207	4	91,933	(8,371)
70	Payroll and Other					28,109
71	Total Taxes	(5)	207	4	(1,330)	(22,861)
72						
73	Total Expenses	(5)	(513)	4	(1,330)	3,677,395
74						
75	Allowance for Funds Used During Consti					81,643
76						
77	Net Income	5	513	(4)	1,330	866,412
78						
79	Calculation of Revenue Requirements					
80	Rate Base	805		(686)	144,917	13,424,971
81	Required Operating Income	61		(52)	10,956	1,014,928
82	Operating Income	5	513	(4)	1,330	866,412
83	Income Deficiency	56	(513)	(48)	9,626	148,516
84	**Revenue Deficiency**	**78**	**(719)**	**(67)**	**13,508**	**208,420**

2026 Plan Year Income Statement Bridge Schedule

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
			Bridge - Supplemental														
Line No.		Supplemental	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Supplemental Direct	CSG Electric Revenue	Customer Advances	Decommissioning	Depreciation Study: TD&G	DI MEC	Distributed Intelligence	Employee Expense	EOL Nuclear Fuel	EV Program	Excess Capacity Proceeds	Hosting
1																	
2	Plant as booked																
3	Production	13,575,547				13,575,547											
4	Transmission	4,515,679				4,515,679											
5	Distribution	6,134,946				6,134,946									1,329		(7,579)
6	General	1,700,255				1,700,255					(2,123)	(772)					
7	Common	1,404,876				1,404,876											
8	Total Utility Plant in Service	27,331,304				27,331,304					(2,123)	(772)			1,329		(7,579)
9																	
10	Reserve for Depreciation																
11	Production	7,830,179				7,830,179								(1,296)			
12	Transmission	1,063,198				1,063,198											
13	Distribution	1,946,064				1,946,064				(6,122)					106		482
14	General	818,474				818,474				(725)	(622)	(175)					
15	Common	677,122				677,122				(764)							
16	Total Reserve for Depreciation	12,335,037				12,335,037				(7,611)	(622)	(175)		(1,296)	106		482
17																	
18	Net Utility Plant																
19	Production	5,745,368				5,745,368								1,296			
20	Transmission	3,452,481				3,452,481											
21	Distribution	4,188,883				4,188,883				6,122					1,224		(8,061)
22	General	881,781				881,781				725	(1,501)	(597)					
23	Common	727,754				727,754				764							
24	Net Utility Plant in Service	14,996,267				14,996,267				7,611	(1,501)	(597)		1,296	1,224		(8,061)
25																	
26	Utility Plant Held for Future Use																
27																	
28	Construction Work in Progress	1,100,422				1,100,422									188		(1,986)
29																	
30	Less: Accumulated Deferred Income Taxes	2,982,281	(1,676)		(632,172)	2,348,434				2,433	(218)	(92)		363	30		(200)
31																	
32	Other Rate Base Items																
33	Cash Working Capital			(96,684)		(96,684)											
34	Materials and Supplies	185,838				185,838											
35	Fuel Inventory	85,634				85,634											
36	Non Plant Assets and Liabilities	99,107				99,107											
37	Customer Advances	(10,577)				(10,577)		(1,019)									
38	Customer Deposits	(31,601)				(31,601)											
39	Prepayments	76,432				76,432											
40	Regulatory Amortizations	54,211				54,211											
41	Total Other Rate Base	459,044		(96,684)		362,360		(1,019)									
42																	
43	Total Average Rate Base	13,573,451	1,676	(96,684)	632,172	14,110,615		(1,019)		5,177	(1,283)	(505)		932	1,381		(9,847)

2026 Plan Year Income Statement Bridge Schedule

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
			Bridge - Supplemental														
Line No.		Supplemental	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Supplemental Direct	CSG Electric Revenue	Customer Advances	Decommissioning	Depreciation Study: TD&G	DI MEC	Distributed Intelligence	Employee Expense	EOL Nuclear Fuel	EV Program	Excess Capacity Proceeds	Hosting
44																	
45	Operating Revenues																
46	Retail Revenue	3,724,469				3,724,469											
47	Interdepartmental	491				491											
48	Other Operating	850,391				850,391	1,415							(130)		40,262	
49	Total Revenue	4,575,351				4,575,351	1,415							(130)		40,262	
50																	
51	Expenses																
52	Operating Expenses																
53	Fuel & Purchased Energy	1,292,781				1,292,781											
54	Power Production	658,107				658,107								(904)			
55	Transmission	290,971				290,971											
56	Distribution	117,710				117,710									179		
57	Customer Accounting	60,061				60,061											
58	Customer Service and Information	174,543				174,543											
59	Sales, Econ Dev, & Other	8,608				8,608											
60	Administrative and General	299,956				299,956							(23)				
61	Total Operating Expenses	2,902,736				2,902,736							(23)	(904)	179		
62																	
63	Depreciation	933,245				933,245			(21,571)	(5,691)	(322)	(110)			136		(236)
64	Amortization	54,152				54,152											
65																	
66	Taxes																
67	Property	191,009				191,009											
68	Deferred Income Tax and ITC	54,850			(242,162)	(187,312)				1,803	(101)	(37)		253	30		(400)
69	Federal and State Income Tax	(228,689)	(10)	595	238,274	10,169	407	6	6,200	(32)	200	71	7	(43)	(129)	11,572	505
70	Payroll and Other	29,174				29,174											
71	Total Taxes	46,344	(10)	595	(3,888)	43,040	407	6	6,200	1,771	100	34	7	210	(98)	11,572	105
72																	
73	Total Expenses	3,936,477	(10)	595	(3,888)	3,933,173	407	6	(15,371)	(3,920)	(222)	(76)	(16)	(693)	216	11,572	(131)
74																	
75	Allowance for Funds Used During Constr	85,667				85,667									10		(330)
76																	
77	Net Income	724,541	10	(595)	3,888	727,845	1,009	(6)	15,371	3,920	222	76	16	564	(206)	28,690	(198)
78																	
79	Calculation of Revenue Requirements																
80	Rate Base	13,573,451	1,676	(96,684)	632,172	14,110,615		(1,019)		5,177	(1,283)	(505)		932	1,381		(9,847)
81	Required Operating Income	1,024,796	127	(7,300)	47,729	1,065,351		(77)		391	(97)	(38)		70	104		(743)
82	Operating Income	724,541	10	(595)	3,888	727,845	1,009	(6)	15,371	3,920	222	76	16	564	(206)	28,690	(198)
83	Income Deficiency	300,254	116	(6,705)	43,841	337,506	(1,009)	(71)	(15,371)	(3,529)	(319)	(114)	(16)	(493)	311	(28,690)	(545)
84	**Revenue Deficiency**	**421,362**	**163**	**(9,409)**	**61,524**	**473,639**	**(1,415)**	**(99)**	**(21,571)**	**(4,952)**	**(448)**	**(160)**	**(23)**	**(692)**	**436**	**(40,262)**	**(765)**

2026 Plan Year Income Statement Bridge Schedul

(1)	(2)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)	(31)	(32)	(33)	(34)	(35)
		Rebuttal Adjustments																
Line No.		Late Payment	Luverne Battery	Nuclear PTC	Production Tax Credit: Solar	Production Tax Credits	Reconnection Fees	Remaining Life: Hydro	Remaining Life: Nuclear	Remaining Life: Salvage	Rider: TCR FERC Reclass	Rider: TCR Update	Rider: TCR Revenue	Sales Fcst Update	Service Quality	Sherco Inventory	TOU Program	Wildfire Capital
1																		
2	Plant as booked																	
3	Production																	
4	Transmission																	
5	Distribution											(1,236)						(2,105)
6	General						1,421					(1)					1,385	
7	Common																	
8	Total Utility Plant in Service						1,421					(1,236)					1,385	(2,105)
9																		
10	Reserve for Depreciation																	
11	Production		3					2,554	(131,945)	(7,580)								
12	Transmission																	
13	Distribution											(89)						267
14	General						218	113	(8,413)								123	
15	Common																	
16	Total Reserve for Depreciation		3				218	2,668	(140,358)	(7,580)		(89)					123	267
17																		
18	Net Utility Plant																	
19	Production		(3)					(2,554)	131,945	7,580								
20	Transmission																	
21	Distribution											(1,147)						(2,372)
22	General						1,203	(113)	8,413			(1)					1,263	
23	Common																	
24	Net Utility Plant in Service		(3)				1,203	(2,668)	140,358	7,580		(1,147)					1,263	(2,372)
25																		
26	Utility Plant Held for Future Use																	
27																		
28	Construction Work in Progress						405					0					290	(298)
29																		
30	Less: Accumulated Deferred Income Taxes		(1)				7	(745)	46,649	2,205		(44)					33	(97)
31																		
32	Other Rate Base Items																	
33	Cash Working Capital																	
34	Materials and Supplies																	
35	Fuel Inventory																	
36	Non Plant Assets and Liabilities																	
37	Customer Advances																	
38	Customer Deposits																	
39	Prepayments																	
40	Regulatory Amortizations																	
41	Total Other Rate Base																	
42																		
43	Total Average Rate Base		(2)				1,600	(1,923)	93,709	5,375		(1,103)					1,521	(2,573)

2026 Plan Year Income Statement Bridge Schedul

(1)	(2)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)	(31)	(32)	(33)	(34)	(35)
		Rebuttal Adjustments																
Line No.		Late Payment	Luverne Battery	Nuclear PTC	Production Tax Credit: Solar	Production Tax Credits	Reconnection Fees	Remaining Life: Hydro	Remaining Life: Nuclear	Remaining Life: Salvage	Rider: TCR FERC Reclass	Rider: TCR Update	Rider: TCR Revenue	Sales Fcst Update	Service Quality	Sherco Inventory	TOU Program	Wildfire Capital
44																		
45	Operating Revenues																	
46	Retail Revenue			(59,643)								(169)	169	(33,972)				
47	Interdepartmental													(0)				
48	Other Operating		0					301	(12,930)	(561)								
49	Total Revenue		0	(59,643)				301	(12,930)	(561)		(169)	169	(33,973)				
50																		
51	Expenses																	
52	Operating Expenses																	
53	Fuel & Purchased Energy																	
54	Power Production															(3,946)		
55	Transmission																	
56	Distribution																	(1,100)
57	Customer Accounting						1,193											
58	Customer Service and Information																	
59	Sales, Econ Dev, & Other																	
60	Administrative and General						700								209			
61	Total Operating Expenses						1,893								209	(3,946)		(1,100)
62																		
63	Depreciation		2				436	2,072	(97,144)	(4,049)		(63)					245	(61)
64	Amortization																	
65																		
66	Taxes																	
67	Property																	
68	Deferred Income Tax and ITC		(1)	2,237	(6)	391	13	(579)	32,306	1,150		(28)					64	(194)
69	Federal and State Income Tax		0	(61,880)	123	(7,824)	(688)	98	(4,293)	(194)		5	49	(9,764)	(60)	1,134	(139)	548
70	Payroll and Other																	
71	Total Taxes		(1)	(59,643)	117	(7,433)	(675)	(480)	28,013	956		(23)	49	(9,764)	(60)	1,134	(76)	354
72																		
73	Total Expenses		1	(59,643)	117	(7,433)	1,655	1,591	(69,131)	(3,093)		(86)	49	(9,764)	149	(2,812)	170	(807)
74																		
75	Allowance for Funds Used During Constr						33										50	
76																		
77	Net Income		(1)	(0)	(117)	7,433	(1,621)	(1,290)	56,202	2,531		(83)	120	(24,208)	(149)	2,812	(119)	807
78																		
79	Calculation of Revenue Requirements																	
80	Rate Base		(2)				1,600	(1,923)	93,709	5,375		(1,103)					1,521	(2,573)
81	Required Operating Income		(0)				121	(145)	7,075	406		(83)					115	(194)
82	Operating Income		(1)	(0)	(117)	7,433	(1,621)	(1,290)	56,202	2,531		(83)	120	(24,208)	(149)	2,812	(119)	807
83	Income Deficiency		1	0	117	(7,433)	1,742	1,145	(49,126)	(2,125)			(120)	24,208	149	(2,812)	234	(1,001)
84	**Revenue Deficiency**		**1**	**0**	**164**	**(10,431)**	**2,445**	**1,607**	**(68,942)**	**(2,983)**			**(169)**	**33,973**	**209**	**(3,946)**	**329**	**(1,404)**

2026 Plan Year Income Statement Bridge Schedul

(1)	(2)	(36)	(37)	(38)	(39)	(40)
		Secondary Calculations				
Line No.		ADIT Prorate for IRS	Bad Debt Expense	Cash Working Capital	Net Operating Loss	Total
1						
2	Plant as booked					
3	Production					13,575,547
4	Transmission					4,515,679
5	Distribution					6,125,355
6	General					1,700,167
7	Common					1,404,876
8	Total Utility Plant in Service					27,321,625
9						
10	Reserve for Depreciation					
11	Production					7,691,916
12	Transmission					1,063,198
13	Distribution					1,940,707
14	General					808,994
15	Common					676,359
16	Total Reserve for Depreciation					12,181,173
17						
18	Net Utility Plant					
19	Production					5,883,631
20	Transmission					3,452,481
21	Distribution					4,184,649
22	General					891,173
23	Common					728,518
24	Net Utility Plant in Service					15,140,451
25						
26	Utility Plant Held for Future Use					
27						
28	Construction Work in Progress					1,099,022
29						
30	Less: Accumulated Deferred Income Taxes	(908)			(123,125)	2,274,724
31						
32	Other Rate Base Items					
33	Cash Working Capital			(321)		(97,005)
34	Materials and Supplies					185,838
35	Fuel Inventory					85,634
36	Non Plant Assets and Liabilities					99,107
37	Customer Advances					(11,597)
38	Customer Deposits					(31,601)
39	Prepayments					76,432
40	Regulatory Amortizations					54,211
41	Total Other Rate Base			(321)		361,020
42						
43	Total Average Rate Base	908		(321)	123,125	14,325,769

2026 Plan Year Income Statement Bridge Schedul

(1)	(2)	(36)	(37)	(38)	(39)	(40)
		Secondary Calculations				
Line No.		ADIT Prorate for IRS	Bad Debt Expense	Cash Working Capital	Net Operating Loss	Total
44						
45	Operating Revenues					
46	Retail Revenue					3,630,853
47	Interdepartmental					491
48	Other Operating					878,749
49	Total Revenue					4,510,093
50						
51	Expenses					
52	Operating Expenses					
53	Fuel & Purchased Energy					1,292,781
54	Power Production					653,257
55	Transmission					290,971
56	Distribution					116,789
57	Customer Accounting		(666)			60,588
58	Customer Service and Information					174,543
59	Sales, Econ Dev, & Other					8,608
60	Administrative and General					300,842
61	Total Operating Expenses		(666)			2,898,379
62						
63	Depreciation					806,888
64	Amortization					54,152
65						
66	Taxes					
67	Property					191,009
68	Deferred Income Tax and ITC				(70,851)	(221,259)
69	Federal and State Income Tax	(6)	192	2	69,677	15,912
70	Payroll and Other					29,174
71	Total Taxes	(6)	192	2	(1,173)	14,835
72						
73	Total Expenses	(6)	(475)	2	(1,173)	3,774,255
74						
75	Allowance for Funds Used During Constr					85,431
76						
77	Net Income	6	475	(2)	1,173	821,269
78						
79	Calculation of Revenue Requirements					
80	Rate Base	908		(321)	123,125	14,325,769
81	Required Operating Income	69		(24)	9,296	1,081,596
82	Operating Income	6	475	(2)	1,173	821,269
83	Income Deficiency	63	(475)	(22)	8,123	260,326
84	**Revenue Deficiency**	**88**	**(666)**	**(31)**	**11,399**	**365,329**

2025-2026 MYRP Adjustment Correction Summary

1	2	3	4	5	7	8	10	11	13	14
Line No.	Adjustment	Intervenor	Intervenor Adjustment		Corrected Adjustment		Change in Adjustment		References	
			2025	2026	2025	2026	2025	2026	Schedule 3A-B	Testimony
1										
2	**Adjustments Accepted needing Correction**									
3	Federal Tax Credits	Uphus - DOC	(21,540)	(10,445)	(21,538)	(10,431)	2	14	Page 4, row 84, column 23	BCH-3, Halama Rebuttal, Section II.A.16
4	Nuclear Decommissioning Accrual	Golden - DOC	(17,739)	(17,739)	(21,571)	(21,571)	(3,832)	(3,832)	Page 2, row 84, column 10	BCH-3, Halama Rebuttal, Section II.A.3
5	Nuclear End of Life	Golden - DOC	(239)	(239)	(691)	(692)	(452)	(453)	Page 2, row 84, column 15	BCH-3, Halama Rebuttal, Section II.A.8
6										
7	**Adjustments Opposed needing Correction**									
8	Wildfire Mitigation	Borden - DOC	(4,590)	(16,435)	(2,908)	(17,532)	1,682	(1,097)	Not applicable	BCH-3, Halama Rebuttal, Section III.A.2
9	Prepaid Pension Asset	Myers - GDS Assc	(11,284)	(10,658)	(11,623)	(11,065)	(339)	(407)	Not applicable	BCH-3, Halama Rebuttal, Section III.A.3
10	Research and Experimentation Federal Tax Credits	Uphus - DOC	(1,019)	(1,019)	(396)	(396)	623	623	Not applicable	BCH-3, Halama Rebuttal, Section III.B.1
11	Researrch and Experimentation State Tax Credits	Uphus - DOC	(269)	(269)	(98)	(98)	171	171	Not applicable	BCH-3, Halama Rebuttal, Section III.B.1
12	ND Investment Tax Credits	Uphus - DOC	(35)	(37)			35	37	Not applicable	BCH-3, Halama Rebuttal, Section III.B.2
13	Depreciation Rate Base	Jones - DOC	817	1,017			(817)	(1,017)	Not applicable	BCH-3, Halama Rebuttal, Section III.A.4
14	Employee Awards and Gifts	Lee - OAG	(1,027)	(1,027)	(741)	(772)	286	255	Not applicable	BCH-3, Halama Rebuttal, Section III.B.8
15	Liquidated Damages	Johnson - DOC	(5,011)	(5,011)	(3,367)	(3,367)	1,644	1,644	Not applicable	BCH-3, Halama Rebuttal, Section III.B.5
16	Insurance Premiums	Jones - DOC	(8,143)	(8,953)	(5,294)	(5,821)	2,849	3,132	Not applicable	BCH-3, Halama Rebuttal, Section III.B.6
17	Association Dues	Lee - OAG	(2,351)	(2,351)	(677)	(677)	1,674	1,674	Not applicable	BCH-3, Halama Rebuttal, Section III.B.7
18										
19	**Intervenor Adjustments Not Calculated by Intervenor**									
20	Communication Infrastructuve	Joint Intervenors			(528)	(1,639)	(528)	(1,639)	Not applicable	
21	Undergrounding	OAG			(44)	(209)	(44)	(209)	Not applicable	
22										
23		Total	(72,429)	(73,165)	(69,475)	(74,270)	2,954	(1,105)		

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

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

Xcel Energy		Information Request No.	1009
Docket No.:	E002/GR-24-320		
Response To:	Office of the Attorney General		
Requestor:	Peter Scholtz		
Date Received:	May 21, 2025		

Question:
Reference: Vol 4 VIII. A31. Rate Case Expense, page 2

A. Provide the assumptions and calculations the Company used to determine the 2025 Test Year amount for each of the following:
   1. Outside legal fees
   2. Consulting
   3. Regulatory fees
   4. Administrative costs
B. Provide the rate case expense amortization amount, and the actual costs incurred by Company for the previous rate case proceeding (MPUC Docket 21-630) for each of the following:
   1. Outside legal fees
   2. Consulting
   3. Regulatory fees
   4. Administrative costs
C. Provide the invoices paid by the Company for rate case expenses for the previous rate case proceeding (MPUC Docket 21-630) for each of the following:
   1. Outside legal fees
   2. Consulting
   3. Regulatory fees
   4. Administrative costs

Response:

A. The amount of Outside Legal Fees, Consulting Fees, Regulatory Fees, and Administrative Costs is an estimate developed by the Company based on actual costs incurred in support of our most recent rate cases. Historical costs were adjusted to reflect the circumstances of the current 2025-2026 Multi-Year Rate Plan (MYRP). Please see Attachment A to this response for the detailed breakout of the four categories.

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

B. Please see Table 1 below for rate case expense forecasted by the Company for the previous rate case proceeding (Docket No. E002/GR-21-630). These expenses were amortized equally over a three-year period. Please see Table 2 for the actual expenses incurred.

Table 1
E002/GR-21-630 Rate Case Expense Amortization

Outside legal fees	$2,570,000
Consulting	$464,000
Regulatory fees	$1,200,000
Administrative costs	$485,300
Non-regulated Estimate	-$32,997
Total rate case expenses	$4,686,303

C. Please see Table 2 below for the total amounts of the expenses paid by the Company for rate case expenses for the previous rate case proceeding (Docket No. E002/GR-21-630). As shown in Tables 1 and 2, the Company incurred more rate case expenses than were included in the case for recovery. Please see Attachment B for the invoices paid by the Company.

Table 2
E002/GR-21-630 Rate Case Expenses

Outside legal fees	$2,283,885
Consulting	$544,748
Regulatory fees	$1,602,454
Administrative costs	$388,582
Total Expenses	$4,819,669

Please note, several of the invoices provided in Attachment B do not exactly match what was charged to the 2022-2024 Electric MYRP. There are situations where the Company purchases office supplies or pays for studies and then a portion of those costs are allocated to different operating companies. Therefore, some of the invoices show amounts that are more than what was actually charged to the 2022-2024 Electric MYRP.

It is also important to note that while the invoices provided in Attachment B show the majority of the costs incurred for our 2022-2024 Electric MYRP, there are certain expenses that are incurred that do not have an associated invoice as they are internal Company charges.

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Portions of the attachments provided with this response are marked Not Public, as they contain information the Company considers to be trade secret as defined by Minn. Stat. §13.37(1)(b). This information includes confidential contract pricing and terms which, if disclosed, could jeopardize future contract negotiations. The information also represents information not generally known or readily ascertainable by others who could obtain a financial or otherwise competitive advantage. Disclosure of this information provides economic value to potential contractors which could potentially result in higher costs to our customers if such information is used against our interests. Thus, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500.

Portions of the attachments that are not relevant to rate case expense for the Company's 2022-2024 Electric Multi-Year Rate Plan have also been redacted.

Witness:	Benjamin C. Halama
Preparer:	Amber Hedlund
Title:	Manager, Regulatory Affairs
Department:	NSPM Regulatory
Telephone:	612-337-2268
Date:	June 10, 2025

Company's Response to DOC IR-2106

	2024 Actual	
	NSPM Electric	Minnesota Electric Jurisdiction
General Liability Insurance	$3,906,136	$3,397,112
Captive Distribution Credit	(2,105,154)	(1,830,823)
Total General Liability	$1,800,982	$1,566,289

Company's Books and Records for 2024

2024 Actual		
General Ledger Account	FERC Account	NSPM Electric
Worker's Comp and Other	925 - Injuries and damages	$995,630
Insurance - General Liability	925 - Injuries and damages	1,800,982
Insurance - Excess Liability	925 - Injuries and damages	10,745,694
Insurance - Directors and Officers	925 - Injuries and damages	1,248,087
Insurance - Fiduciary	925 - Injuries and damages	347,737
Insurance - Other	925 - Injuries and damages	140,905
Insurance - Cyber	925 - Injuries and damages	608,951
Insurance - Nuclear Liability	925 - Injuries and damages	2,997,625
Insurance - Nuclear Liability ICRP	925 - Injuries and damages	(1,819,214)
	Total FERC 925	$17,066,397

Northern States Power - Minnesota 2024 FERC Form 1 Report
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FERC Account	Amount
(925) Injuries and Damages	$17,066,397

Northern States Power Company, doing business as Xcel Energy
Information Request

Docket No.:	E002/GR-24-320		
	2025-2026 Electric Multiyear Rate Plan		
Requestor:	Xcel Energy		
Requested From:	Minnesota Office of the Attorney General		
Date of Request:	September 15, 2025	Information Request No.	45
Response Due:	September 25, 2025		

<u>Question:</u>
Reference: Lee Direct page 7, lines 10-17

Has the OAG assessed whether these costs are at the MN jurisdictional level? Please explain your answer.

<u>Response:</u>

The recommendation to remove $2,350,561 is based on the EEI dues invoiced for 2025. This amount is not the MN jurisdictional amount.

Witness:	Shoua Lee
Preparer:	Shoua Lee / Wendy Raymond
Title:	Financial Analyst / AAG
Department:	OAG-RUD
Telephone:	651-300-7762
Date:	September 25, 2025