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Surrebuttal Testimony and Schedules
Lisa R. Peterson

Before 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. E002, PT-7157/SA-25-129
CAH Docket No. 22-2500-40870

Surrebuttal Testimony of
Lisa R. Peterson

January 22, 2026

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Lisa R. Peterson. I am the Director of Regulatory Pricing and Analysis for Northern States Power Company d/b/a Xcel Energy (Xcel Energy or the Company).

Q. ARE YOU THE SAME LISA R. PETERSON WHO PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes. My Direct Testimony was filed on November 21, 2025 and my Rebuttal Testimony was filed on January 9, 2026.

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

A. I am the witness responsible for analyzing the just compensation to be paid by the City of Slayton (City or Slayton) pursuant to Minn. Stat. § 216B.45. The purpose of my Surrebuttal Testimony is to respond to the testimony of City witnesses David Berg, Mark Fritsch, and Mark S. Mitchell, and to Department witness Cuong Ngo. I also provide an updated Lost Revenue Calculation to incorporate any changes since my Direct Testimony, which is included as Schedule 1.

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. I first describe my general agreement with the testimony of Department witness Ngo, and explain why I disagree in a few areas.

Second, I explain areas in which I disagree or agree with the City's recommendations. In particular, I agree to make two changes to my lost revenue calculation related to transmission costs and Conservation Improvement Program costs recommended by City witnesses.

Q. HOW IS YOUR TESTIMONY STRUCTURED?

A. I will first respond to the testimony and analysis of Department witness Ngo. Then, I will respond to the witnesses for Slayton. I will conclude by providing my overall recommendation on just compensation.

Q. ARE ANY OTHER WITNESSES ADDRESSING ISSUES RELATED TO JUST COMPENSATION?

A. Yes. Company witness Bixuan Sun provides Surrebuttal Testimony regarding several matters related to just compensation. Her analysis is incorporated into my testimony and overall recommendation.

II. RESPONSE TO DEPARTMENT

Q. PLEASE DESCRIBE THE REBUTTAL TESTIMONY OF DEPARTMENT WITNESS NGO.

A. Department witness Ngo did not provide a specific recommendation regarding a just compensation amount, but provided guidance to the Commission on how the Department believes just compensation should be determined.

Q. DO YOU AGREE WITH DEPARTMENT WITNESS NGO'S TESTIMONY?

A. Department witness Ngo provides recommendations related to:

- The purchase price for the assets Slayton seeks to acquire;
- The time period for lost revenues;

- The calculation of lost revenue;
- The method of paying lost revenue;
- The type of integration expenses that should be included in just compensation; and
- The stranded costs of the Slayton West (SLW) substation.

I agree with most of Department witness Ngo's testimony. There are some issues that I do not agree with, and I will explain why.

A. Value of Property

Q. WHAT IS DEPARTMENT WITNESS NGO'S RECOMMENDATION RELATED TO THE PURCHASE PRICE OF THE ASSETS?

A. His recommendation is that the net book value should be used to establish the value of the assets to be purchased by Slayton, and that the net book value should be finalized on the actual transfer date, including a final asset list, original cost, and accumulated depreciation.[1]

This is consistent with the Company's recommendation, which I understand the City has agreed to.[2]

B. Lost Revenue Time Period

Q. WHAT IS DEPARTMENT WITNESS NGO'S RECOMMENDATION RELATED TO THE TIME PERIOD FOR LOST REVENUES?

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[1] Rebuttal Testimony of Cuong Ngo at 6:21–7:3 (Jan. 9, 2026) (Ngo Rebuttal).
[2] Direct Testimony of David Berg at 11:3–11 (Nov. 21, 2025) (Berg Direct); Rebuttal Testimony of David Berg at 2:19–22 (Jan. 9, 2026) (Berg Rebuttal).

A. He recommends that the time period for lost revenues should be ten years. Witness Ngo bases this conclusion primarily on the Commission's prior decisions, under Minn. Stat. § 216B.44, to use a ten-year compensation period.[3]

Q. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No, I do not. The facts in this case support a different outcome.

As I have explained in previous rounds of testimony, the cases under section 216B.44 all involved the expansion of an existing municipal utility into the service territory of a cooperative utility. Cooperative utilities in Minnesota are primarily distribution utilities. In contrast, Xcel Energy is a vertically integrated utility with extensive generation and transmission investments, which are much larger and longer-lived than distribution investments. In fact, as I noted in my Rebuttal Testimony, distribution system costs represent only around 8.6 percent of the total costs for customers.[4] Prior Commission decisions have been focused on planning horizons, which are different for Xcel Energy because it has a different role than a distribution cooperative.[5]

While the Commission has not determined lost revenue cases involving generation, the Federal Energy Regulatory Commission (FERC) has. FERC has a specific rule to permit the recovery of stranded generation costs when customers leave a utility system.[6] In the only two cases decided under that rule,

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[3] Ngo Rebuttal at 8:3–10.
[4] Rebuttal Testimony of Lisa R. Peterson at 11:25–12:1 (Peterson Rebuttal).
[5] *In the Matter of the Application of the Grand Rapids Public Utilities Commission to Extend its Assigned Service Area into the Area Presently Served by Lake Country Power*, Docket No. E243, 106/SA-03-896, ORDER DETERMINING COMPENSATION at 3 (Sept. 29, 2005), affirmed 731 N.W.2d 866 (Minn. Ct. App. 2007).
[6] 18 C.F.R § 35.26(c)(2)(1).

FERC has established lost revenue recovery periods of 20 and 15 years.[7] In the absence of prior Commission decisions involving lost revenue for generation, it is reasonable to look to these decisions from FERC.

In addition, as shown in Table 1 of my Rebuttal Testimony,[8] most of the cases under section 216B.44 involved small numbers of existing customers and undeveloped areas that could be developed to produce revenue in the future. In other words, most of the lost revenue was speculative. In contrast, the lost revenues in Slayton are not speculative at all – the Company has provided service to Slayton for decades and has clear records of this revenue.

For all of these reasons, I conclude that relying on the Commission's prior orders is not a reasonable basis for limiting lost revenue to only 10 years. Instead, the lost revenue time period should be established based on the specific facts in this case. As explained in my Direct and Rebuttal Testimonies, the Company recommends a lost revenue time period of 20 years.[9]

C. Calculation of Lost Revenue

Q. WHAT IS DEPARTMENT WITNESS NGO'S LOST REVENUE RECOMMENDATION?

A. He provides recommendations regarding the inclusion of future customers in lost revenue calculations and avoided costs.

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[7] City of Las Cruces, New Mexico v. El Paso Electric Company, 87 FERC ¶ 61,201, 61,750 (May 26, 1999); City of Alma, Michigan, 96 FERC ¶ 61,163, 61,714 (July 30, 2001).

[8] Peterson Rebuttal at 4:1–3, Table 1.

[9] I also respond to the City's arguments about the lost revenue time period below.

Q. WHAT IS DEPARTMENT WITNESS NGO'S RECOMMENDATION REGARDING THE INCLUSION OF FUTURE CUSTOMERS IN LOST REVENUE?

A. Department witness Ngo recommends that lost revenue calculations should include future customers. In making this recommendation, he relies on an interpretation of Minn. Stat. § 216B.45 and prior Commission decisions.[10] I agree with Department witness Ngo's recommendation and have included a provision for future customers in the lost revenue calculation. I address the City of Slayton's arguments about that calculation below.

Q. WHAT IS DEPARTMENT WITNESS NGO'S AVOIDED COSTS RECOMMENDATION?

A. He recommends that avoided costs (which are excluded from the lost revenue calculation) "must be based on the costs [the utility] 'will actually shed' due to the loss of the customers."[11] Department witness Ngo recommends that avoided costs should include:

- "Fuel and purchased power costs that vary directly with Slayton's load;
- Clearly variable O&M expenses that can be shown to decrease when Slayton leaves . . .; and
- Any demonstrable reductions in customer service or billing costs attributable to the loss of Slayton's accounts."[12]

Department witness Ngo further explained that fixed costs "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."[13]

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[10] Ngo Rebuttal at 8:12–9:3.
[11] Ngo Rebuttal at 9:11–12.
[12] Ngo Rebuttal at 9:15–10:2.
[13] Ngo Rebuttal at 10:3–6.

Q. DO YOU AGREE WITH DEPARTMENT WITNESS NGO'S RECOMMENDATIONS ON AVOIDED COST?

A. Generally, yes. In particular, I agree with Department witness Ngo that costs should only be treated as avoided if there are demonstrable cost reductions or costs are otherwise shown to actually decrease. Speculation that costs might decrease, or general conclusions that the Company should be able to adjust its operations in an unspecified way, are not sufficient to justify treating a cost as avoided. I also agree with Department witness Ngo that the City has an obligation to show, through actual evidence, that specific costs will actually be avoided.

I do not agree with Department witness Ngo's suggestion that purchased power costs will be avoided. As I explain in more detail in my response to the City, below, the Company's costs related to existing power purchase agreements (PPAs) will not change if Slayton exits the system.

D. Method for Paying Lost Revenue

Q. WHAT IS DEPARTMENT WITNESS NGO'S RECOMMENDATION ABOUT THE METHOD FOR PAYING LOST REVENUE?

A. He recommends that lost revenue be set using a mill rate, which is applied on a per-kWh basis to sales over a time period.[14] I do not agree with this recommendation.

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[14] Ngo Rebuttal at 11:10–13.

Department witness Ngo relies primarily on the Commission's decision in Docket No. E135, 298/SA-05-1274, in which the City of Redwood Falls extended its service territory into areas that had been served by Redwood Electric Cooperative.[15] While the Commission did set a mill rate in that matter, there are several differences between Docket No. E135, 298/SA-05-1274 and this case that justify a different treatment.

First, the parties in Docket No. E135, 298/SA-05-1274 did not dispute the use of a mill rate.[16] As a result, and neither the Administrative Law Judge or the Commission analyzed whether the use of a mill rate was required or appropriate. Here, the Company does not agree with the use of a mill rate.

Further, in the most recent case in which the Commission actually evaluated which compensation method to use, the Commission used a lump-sum payment for existing customers, and a mill-rate for speculative revenue from future customers.[17] As I noted in my Rebuttal Testimony, the customers in Slayton are existing customers. For that reason, Slayton customers are most comparable to the existing customers in the *Rochester* case, where the costs for existing customers were recovered in a lump sum payment.[18] A close review of

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[15] Ngo Rebuttal at 11:6–9. *See In the Matter of the Application of the City of Redwood Falls to Extend its Assigned Service Area into the Area Presently Served by Redwood Electric Cooperative*, Docket No. E135, 298/SA-05-1274, ORDER DETERMINING COMPENSATION (June 27, 2007).
[16] *In the Matter of the Application of the City of Redwood Falls to Extend its Assigned Service Area into the Area Presently Served by Redwood Electric Cooperative*, Docket No. E135, 298/SA-05-1274, FINDINGS OF FACT, CONCLUSIONS, AND RECOMMENDED ORDER at 19 (Jan. 5, 2007).
[17] *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 at Order Point 1 (Nov. 30, 1995).
[18] Peterson Rebuttal at 37:6–11.

the *Rochester* case indicates that applying it here would result in the use of a lump sum payment for Slayton's lost revenues.

Second, while I am not an attorney, I noted in my Direct Testimony that the text of section 216B.45 provides that the Company has consented to the purchase of its property "for just compensation."[19] This statute can be read to require the payment of just compensation before or at the time of the transfer of property.

Finally, the use of a mill rate creates risk for both the Company and customers in Slayton. If a mill rate is set and customers in Slayton choose to electrify or purchase electric vehicles, the use of a mill rate could result in an overcollection for the Company. Individual customers who choose to invest in these beneficial technologies could be harmed, and it could discourage customers from considering these options. On the other hand, the Company could be harmed if Slayton itself, or its customers, invests in distributed energy resources that could significantly reduce sales. Or, given Slayton's lack of experience operating an electric utility, it is possible that Slayton may be unable to pay at some point in the future. Ultimately, the uncertainty that would result from a mill rate is not beneficial to either party. If the Commission requires an alternative to the lump-sum payment, the Company recommends the use of a scheduled payment.[20]

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[19] Direct Testimony of Lisa R. Peterson at 27:2–4 (Nov. 21, 2025) (Peterson Direct).
[20] Peterson Direct at 28:20–29:5, 30:2–7.

E. Integration Expense

Q. WHAT IS DEPARTMENT WITNESS NGO'S INTEGRATION EXPENSE RECOMMENDATION?

A. He recommends that the Company should be compensated for "incremental, Slayton-specific integration expenses," "provided these costs are clearly caused by the transfer, reasonably estimated, and not double-counted in net plant or loss-of-revenue calculations."[21]

In general, I agree. I clarify, though, that the Company does not intend to estimate the costs of engineering studies required to assess the separation of Slayton load from the system, what upgrades would be identified in those studies, or what those upgrades might cost. Instead, the Company proposes that Slayton pay the actual cost of those studies and any required upgrades that are identified. This will ensure that Slayton is not charged for unreasonable costs but only pays exactly those integration costs that are being caused by Slayton's decision to exit the system.

The Company recognizes that this may create timing issues, but they are unavoidable. As noted in my Rebuttal Testimony, there are complicated engineering issues involving Slayton's exit.[22] The Company will not know the total cost of the studies or any resulting upgrades until they are completed, and does not plan to begin engineering studies until Slayton confirms that it plans to move forward with its proposal to exit the system.

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[21] Ngo Rebuttal at 12:7–11.
[22] Peterson Rebuttal at 38:13–41:16.

Q. WHAT DO YOU MEAN WHEN YOU REFER TO SYSTEM UPGRADES?

A. When I refer to "system upgrades" in this testimony, I am referring to the results of distribution or transmission engineering studies. These studies identify system changes that are necessary to ensure system reliability and safety. These are the system upgrades that I refer to, and the Company does not intend to include any upgrades in just compensation that are not identified as necessary to maintain safety and reliability.

F. Stranded Costs

Q. WHAT IS DEPARTMENT WITNESS NGO'S RECOMMENDATION ABOUT STRANDED COSTS OF THE SLW SUBSTATION?

A. He recommends that an asset could be included as a stranded cost if "a specific substation or similar asset was primarily justified by Slayton's load and will become significantly underutilized or unused after transfer."[23] Department witness Ngo also suggests that the Company should analyze how the asset will be used after the transfer, limit the recovery of stranded assets to the portion "clearly attributable to the loss of Slayton," and ensure that stranded assets are not already embedded in the loss of revenue analysis.[24]

In general, I agree. I provide additional information about the SLW substation below, in response to the City, which I believe is responsive to witness Ngo's request. I have also ensured that the SLW substation was removed from the lost revenue calculation, so it is not double-counted. I believe the SLW substation would be treated as a stranded asset under witness Ngo's criteria.

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[23] Ngo Rebuttal at 13:7–10.
[24] Ngo Rebuttal at 13:10–18.

III. RESPONSE TO CITY

Q. WHICH WITNESSES DO YOU RESPOND TO FROM THE CITY?

A. I respond to the testimony of City witnesses Berg, Mitchell, and Fritsch related to just compensation.

Q. DO YOU AGREE WITH THE RECOMMENDATIONS AND ANALYSIS PROVIDED BY THE CITY WITNESSES?

A. For the most part, I do not agree with the City witnesses. There are, however, a few areas in which I do agree and in which I propose changes to my lost revenue calculation. I address the City witnesses' arguments and analyses, and provide my response to them in this section.

A. Lost Revenues

Q. WHAT IS THE CITY'S LOST REVENUES RECOMMENDATION?

A. While no City witness provides a clear statement, it is my understanding that the City has not changed its position and continues to recommend a lost revenue amount of 4.2 mills/kWh,[25] which is equivalent to approximately $82,000 per year, compared to approximately $2.9 million in annual revenues from Slayton that will no longer be recovered if Slayton exits the system.

Q. WHAT TOPICS WILL YOU ADDRESS FROM THE CITY'S TESTIMONY?

A. I will respond to the following topics discussed in the City's Rebuttal Testimony:

- The use of growth rates for customer counts and use per customer;

[25] Berg Direct at 16:4–9.

- Fixed production avoided costs;
- Variable production avoided costs;
- Transmission avoided costs;
- Distribution avoided costs;
- Customer avoided costs; and
- The relevant time period for calculating lost revenue.

I will address each of these topics in turn. I also provide overarching comments on the City's lost revenues analysis.

1. Growth Rates for Customer Counts and Use Per Customer

Q. WHAT GROWTH RATES FOR CUSTOMER COUNT AND USE PER CUSTOMER ARE INCLUDED IN YOUR LOST REVENUE CALCULATION?

A. As I explained in my Direct Testimony, the lost revenue calculation includes growth rates for customer count and use per customer that are the same as the forecasts included in Xcel Energy's pending rate case.[26]

Q. WHAT IS THE CITY'S RECOMMENDATION REGARDING GROWTH RATES FOR CUSTOMER COUNTS AND USE PER CUSTOMER?

A. City witness Berg states that these growth rates are not appropriate for this specific case, based on his argument that the Slayton area has experienced different population growth rates in the past. He points to data about Slayton's historical population growth rates, and census data about Murray County and Slayton.[27]

[26] Peterson Direct at 18:9–19:8.
[27] Berg Rebuttal at 7:4–8:7.

Q. DO YOU AGREE WITH THE CITY'S RECOMMENDATION?

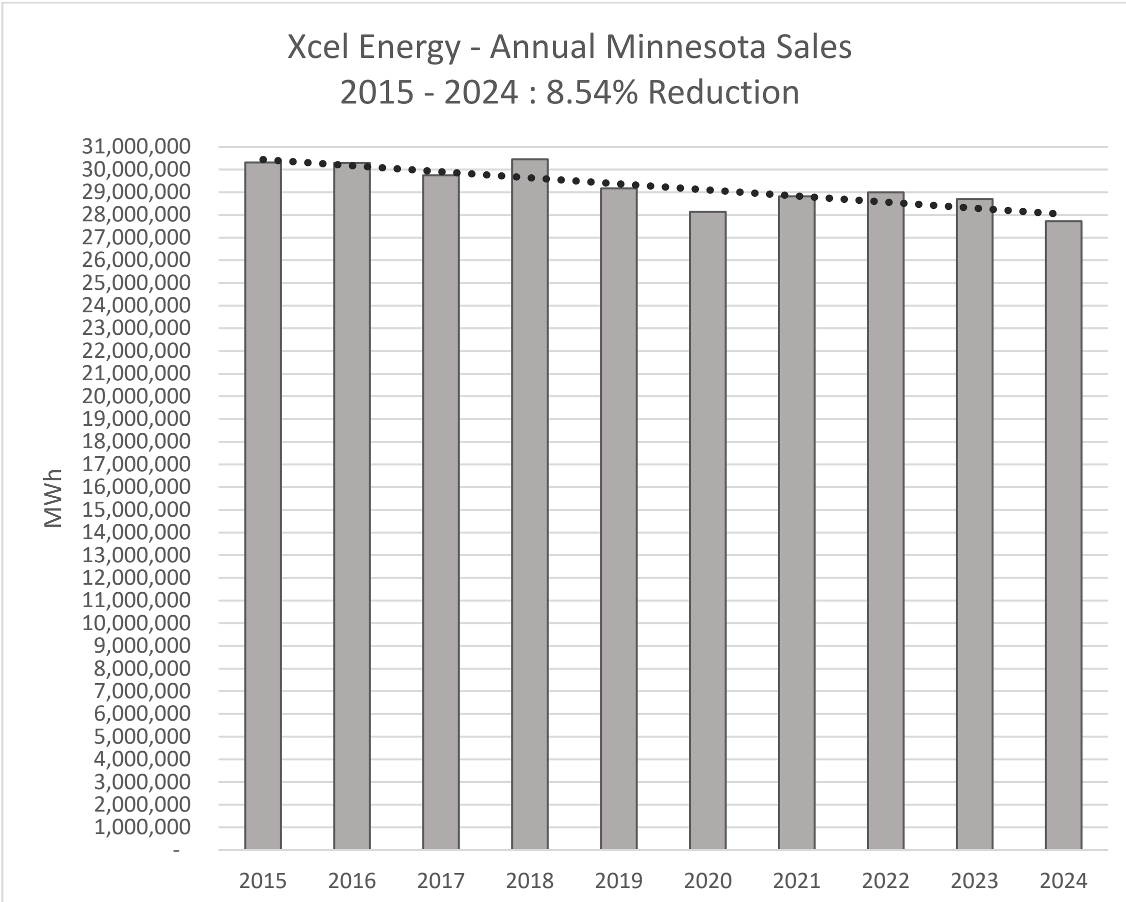
A. Not entirely. I do agree that the use of growth rates should be analyzed based on the facts in the record. I do not, however, agree that City witness Berg has produced evidence showing that the Company's future growth rate projections are unreasonable. Instead, witness Berg has produced evidence of Slayton's growth in the past, and assumed – based on no evidence – that it will hold for the future.

In contrast, my analysis is based on Xcel Energy-specific forecasts about what will happen in the future (not the past) for customer counts and use per customer figures.

Q. DO YOU AGREE THAT POPULATION DECLINE IN SLAYTON MEANS THAT THE GROWTH FIGURES ARE INCORRECT?

A. No. I do not dispute the fact that Slayton has experienced population decline and reduced sales volumes from 2015 to 2024, but that does not mean the same thing will continue to happen in the future. The sales figures from Slayton are not unique. Overall retail sales for the Minnesota jurisdiction have also decreased over the same time period, by approximately 8.5 percent. See Figure 1 below.

Figure 1



Q. WHY IS IT RELEVANT THAT SALES IN THE REST OF MINNESOTA HAVE ALSO DECLINED?

A. It is relevant because, even though sales throughout Minnesota have declined in the last ten years, the Company now forecasts growth in customer counts and use-per customer in the future. The City has not identified any flaws in the Company's forecasting methodology, or identified any specific reason that customer count and use per customer patterns would deviate significantly from what the Company forecasts for the state overall. In the absence of specific data showing that Slayton will have a different usage pattern, it is reasonable to assume that Slayton will be consistent with the Company's overall forecast.

Q. DID CITY WITNESS BERG PROVIDE ANY ARGUMENTS ABOUT THE USE PER CUSTOMER GROWTH RATE?

A. No. I note that his arguments are focused exclusively on the customer count growth rate.[28] Even if the customer count growth rate was modified, which I disagree with, City witness Berg has not identified any reason to adjust the use per customer growth rate.

2. Fixed Production Avoided Costs

Q. WHAT IS THE CITY'S RECOMMENDATION FOR FIXED PRODUCTION AVOIDED COSTS?

A. City witness Berg continues to argue that fixed production costs are fully avoidable.[29] His argument is based on his belief that Xcel Energy can avoid the costs of its existing power plants by reducing resource procurements in the future.[30]

Q. DO YOU AGREE WITH THE CITY'S RECOMMENDATION?

A. No. City witness Berg is confusing the costs included in today's rates, which are related to existing power plants, with resources that will be acquired in the future, which are not included in today's rates.

Q. HOW DOES XCEL ENERGY ACQUIRE MORE ELECTRICITY PRODUCTION?

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[28] Berg Rebuttal at 6:5–8:7.
[29] Berg Rebuttal at 10:7–22.
[30] Berg Rebuttal at 10:16–17 ("The 4 MW of capacity currently needed for Slayton can easily supplant 4 MW of the new generation planned by Xcel.").

A. Xcel Energy conducts Integrated Resource Planning, receives approval from the Commission for a plan, and then conducts resource procurement to obtain new generation units. Resource procurement involves soliciting bids for new generation resources.

Q. WOULD REDUCING FUTURE RESOURCE PROCUREMENTS AVOID FIXED PRODUCTION COSTS?

A. No. As explained by Company witness Sun, it is unlikely that Slayton's exit will have an impact on future resource procurements.[31]

Even assuming that City witness Berg is correct that future resource procurements could be reduced, those cost savings would impact future investments which are not included in the rates that are the basis for the lost revenue calculation. And even then, it would take many years for any cost savings to phase into rates. The fixed production costs in the lost revenue calculation are for already-built power plants. Even if future resource procurements are slightly lower, it would not change the cost of the plants that have already been built and would not have any impact on the lost revenue calculation.. As such, fixed production costs are not avoidable.

Q. IF SLAYTON LEAVES THE SYSTEM WILL THERE BE ANY NEW, ALTERNATE REVENUE SOURCES RELATED TO FIXED PRODUCTION?

A. No. City witness Berg suggests that the Company will be able to sell the 4 MW of capacity currently being used to provide electricity in Slayton on the MISO

[31] Surrebuttal Testimony of Bixuan Sun at 5 (Sun Surrebuttal).

market, and that the potential revenues mean that fixed production costs should be treated as avoidable.[32]

Q. DOES THE COMPANY AGREE WITH CITY WITNESS BERG'S ANALYSIS?

A. No, for two reasons. First, as explained in the Surrebuttal Testimony of Company witness Sun, it is uncertain whether any revenues will result from the additional capacity from Slayton. Even if it does, it is unlikely that it will offset the fixed production costs from Slayton.[33]

Second, even if City witness Berg were correct (which he is not), it would not justify treating fixed production costs as fully avoidable. City witness Berg believes that the capacity from Slayton could be sold on the MISO market for $316,820 each year,[34] and that the annual value of fixed production costs is $395,678.[35] That calculation under-estimates the fixed production costs that Slayton customers are currently paying, because it excludes energy-related fixed production costs. These costs do not vary with energy usage; they are fixed costs for our generation plant investment and power purchase agreement capacity costs. These costs are referred to as "energy-related" fixed production costs for rate-making purposes, to recognize that the generation plant was obtained for both capacity and energy purposes. The "capacity-related summer peak production," "capacity-related winter peak production," and the "energy-related production" sub-categories that City witness Berg refers to are all included in the fixed production category in my analysis. As explained in the

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[32] Berg Rebuttal at 42:17–43:2.
[33] Sun Surrebuttal at 5.
[34] Berg Rebuttal at 41:23–26.
[35] Berg Rebuttal at 42:10–16.

Company's Direct Testimony, customers in Slayton are currently contributing approximately $700,000 to fixed production costs.[36] City witness Berg suggests that these costs are close to being offset by MISO market sales, but they are not. Even if he is correct it would suggest that, at most, 45 percent of fixed production costs could be avoided through MISO market sales, assuming that the Company could 1) clear the capacity in every season, and 2) receive more than the highest-ever recorded price in every season.

Q. WHAT IS YOUR CONCLUSION REGARDING FIXED PRODUCTION COSTS?

A. I conclude that fixed production costs are not avoidable.

3. Variable Production Avoided Costs

Q. WHAT IS THE CITY'S RECOMMENDATION REGARDING VARIABLE PRODUCTION COSTS?

A. It appears that the City agrees with me that fuel costs are avoidable. In addition, City witness Berg argues that three other categories of variable production costs are fully avoidable: purchased power costs, Conservation Improvement Program expense, and costs which City witness Berg refers to as "energy allocator" costs. I disagree with most of this analysis.

Q. ARE PURCHASED POWER COSTS AVOIDABLE?

A. No. The Company obtains some of its electricity from third-party companies that own power plants. Xcel Energy contracts with these third-parties to

[36] As shown on Page 6 of my lost revenue model, approximately 24 percent of total revenue is related to fixed production (893,802 / 3,713,015). Multiplied by the estimated Slayton revenues for 2025, that means Slayton customers contribute $701,515 towards fixed production costs. Peterson Direct, Exhibit___(LRP-1), Schedule 3.

purchase electricity (including energy and capacity), and the contracts are typically referred to as power purchase agreements (PPAs).

Q. WHAT IS THE COMPANY REQUIRED TO DO UNDER A PPA?

A. The terms of PPAs are confidential between the Company and the developers and wording can change from one PPA to another. But the general principle is that the third-party agrees to sell the capacity and energy from the generator to Xcel Energy, and Xcel Energy agrees to buy it.

Q. WHEN DO THE THIRD-PARTY GENERATORS PRODUCE ENERGY AND CAPACITY THAT XCEL ENERGY IS REQUIRED TO PURCHASE?

A. The Company is required to purchase capacity in every season regardless of whether the generator actually runs. The Company is required to purchase energy when the generator is dispatched. Dispatch decisions for generators in the MISO region are made by MISO, and the Company is required to pay for the generation that results when MISO dispatches a unit.

Q. CAN XCEL ENERGY CANCEL ITS PPA CONTRACTS?

A. No. PPAs are binding contracts. Xcel Energy is obligated to purchase the capacity and energy from these third-party generators. Through its PPAs, Xcel Energy has contractually promised to pay for the energy produced when the generator is dispatched, and the capacity even when it is not dispatched. It is not possible to cancel or alter these contracts, which means that the cost of PPAs cannot be avoided.

Q. ARE CONSERVATION IMPROVEMENT PROGRAM COSTS AVOIDABLE?

A. Xcel Energy operates a Conservation Improvement Program (CIP) as required by state law.[37] Through CIP, the Company designs programs to encourage customers to conserve energy. CIP programs can include rebates on light bulbs and efficient appliances or alternative rates to encourage conservation. City witness Berg argues that these costs are avoidable because the Company is required to achieve 1.75 percent gross sales conservation through CIP, and the amount of gross annual sales will reduce after Slayton exits the system.[38] I do not entirely agree with this argument.

Q. HAS THE COMPANY HISTORICALLY PROVIDED CIP REBATES TO CUSTOMERS IN SLAYTON?

A. Yes. From 2016 to 2025, the Company provided $186,898.51 in CIP rebates to customers living in Slayton, for an average of approximately $18,700 per year.[39] I agree that these rebates, which are included in CIP costs, will be avoided in the future and I will recognize an amount of $18,700 as avoided variable production costs in the first year of the lost revenue calculation. Because of the way the model is designed, adjusting the first year will ensure that the change is captured in each future year. This change lowers the lump sum by approximately $195,000.

I do not, however, agree that Slayton's exit will have a noticeable impact on overall CIP program design. The amount of kWh sold in Slayton is small enough compared to system totals that it will not have an impact on the way

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[37] Minn. Stat. Ch. 216C.
[38] Berg Rebuttal at 12.
[39] Ex.___(LRP-3), Schedule 2.

that CIP programs are designed or operated, other than the fact that the people living in Slayton will no longer be able to take advantage of them.

Q. ARE "ENERGY ALLOCATOR" COSTS AVOIDABLE?

A. No. City witness Berg argues that a number of costs should be treated as avoidable because they are allocated using an E8760 allocator in the Company's Class Cost of Service Study (CCOSS).[40] But the Commission has explained in two prior cases that CCOSS allocation methodology is not an appropriate basis for the lost revenue analysis being conducted here:

> Allocating costs among classes of customers who are actually on a utility's system, contributing to the system's fixed costs through their monthly bills, is fundamentally different from determining what costs a utility will avoid – that is, will stop incurring – if it loses particular customers.[41]

City witness Berg's argument is the exact argument that was rejected by the Commission in these prior cases. As the Commission further noted in the *Redwood Falls* proceeding, "the issue is not how the [utility] allocates and reflects [costs] in its rate schedule, but how the loss of actual customers to the City will actually affect its [costs]."[42] The fact that the Company allocates some of these shared costs to customer classes using an E8760 energy allocator does not have any bearing on whether they will actually be reduced when Slayton exits the

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[40] Berg Rebuttal at 13:1–7.

[41] *In the Matter of the Application of the Grand Rapids Public Utilities Commission to Extend its Assigned Service Area into the Area Presently Served by Lake Country Power*, Docket No. E243, 106/SA-03-896, ORDER DETERMINING COMPENSATION at 15 (Sept. 29, 2005), affirmed 731 N.W.2d 866 (Minn. Ct. App. 2007); *In the Matter of the Application of the City of Redwood Falls to Extend its Assigned Service Area into the Area Presently Served by Redwood Electric Cooperative*, Docket No. E135, 298/SA-05-1274, ORDER DETERMINING COMPENSATION at 13 (June 27, 2007).

[42] *In the Matter of the Application of the City of Redwood Falls to Extend its Assigned Service Area into the Area Presently Served by Redwood Electric Cooperative*, Docket No. E135, 298/SA-05-1274, ORDER DETERMINING COMPENSATION at 12 (June 27, 2007).

system. The City has not offered any evidence that any of these costs will be reduced or avoided after Slayton exits the system. The Company has reviewed them, and concludes that the costs will not be avoided.

4. *Transmission Avoided Costs*

Q. WHAT IS THE CITY'S RECOMMENDATION RELATED TO TRANSMISSION AVOIDED COSTS?

A. The City recommends that transmission costs are fully avoided. The City's primary argument was presented by City witness Mitchell, who argued that the operation of MISO regional pricing would allow the Company to avoid Slayton's share of lost transmission revenues.[43] I will respond to City witness Mitchell in this sub-section.

The City also provides extensive testimony about what Xcel Energy did or said when negotiating with the City, or with other municipalities. I do not provide any response to this testimony. While I am not an attorney, I understand that it is not appropriate to introduce evidence or provide discussions in testimony about confidential negotiations with either the City or other municipalities.

Q. WHAT IS YOUR RESPONSE TO CITY WITNESS MITCHELL'S ARGUMENT RELATED TO TRANSMISSION COSTS?

A. Having reviewed City witness Mitchell's testimony carefully and consulted with transmission personnel at the Company, I agree that in this case transmission costs should be treated as fully avoidable. I have made that adjustment in my updated lost revenue calculation, which is presented in Section IV, below. This

[43] Rebuttal Testimony of Mark S. Mitchell at 4:20–5:5 (Jan. 9, 2026) (Mitchell Rebuttal).

change reduces the annual lost revenue amount by approximately $325,000 in the first year, and reduces the calculated lump sum payment by approximately $5.3 million.

Q. WHY ARE YOU CHANGING YOUR RECOMMENDATION ON TRANSMISSION AVOIDED COSTS?

A. As I noted in my Direct Testimony, Slayton's exit will result in a loss of transmission revenue. I now conclude, though, that this loss of revenue will be offset by additional revenue from wholesale transmission customers. Theoretically, the loss of retail revenue from Slayton should be matched by additional wholesale revenue. It is also my understanding that customers in Slayton will continue to contribute to the costs of the regional transmission system as transmission customers of Great River Energy.

While I do not necessarily agree with all of City witness Mitchell's analysis and conclusions, I agree that the MISO market structure will allow the Company to continue to recover its transmission revenue requirement such that our other customers will not be harmed – as it relates to transmission costs – by Slayton's exit. I have incorporated this adjustment into my updated lost revenue calculation, presented below.

5. Distribution Avoided Costs

Q. WHAT IS THE CITY'S RECOMMENDATION REGARDING DISTRIBUTION COSTS?

A. City witness Berg argues that distribution costs are 100 percent avoidable because Slayton is purchasing the distribution assets in Slayton.[44]

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[44] Berg Rebuttal at 17:1–2.

Q. DO YOU AGREE WITH THE CITY?

A. No. City witness Berg is mixing up two parts of the just compensation analysis. As I have explained before, the lost revenues related to distribution costs reflect Slayton's contribution to the shared costs of the entire distribution across the whole state. As explained by City witness Mitchell, "[a] customer in Minneapolis would pay a portion of the cost of lines serving Slayton and a customer in Slayton would pay a portion of the cost of lines serving Minneapolis."[45] While City witness Mitchell was referring to transmission lines, the same thing is true for distribution lines.

Q. WHAT WILL HAPPEN TO SLAYTON'S SHARE OF DISTRIBUTION COSTS IF SLAYTON LEAVES THE SYSTEM?

A. The contribution that Slayton currently provides towards shared distribution system costs will be gone. The Company will no longer receive those revenues. If the lost revenues are not recovered from Slayton, then in the next rate case, rates will be increased for all customers to make up for the loss.

Q. DO MINNESOTA LAW AND COMMISSION PRECEDENT RECOGNIZE THAT LOST REVENUES ARE DIFFERENT FROM PURCHASING ASSETS?

A. Yes. Minnesota law requires that Slayton pay for both "the original cost of the property less depreciation" *and* "loss of revenue to the utility."[46] While I am not an attorney, this statutory language is consistent with my lost revenue analysis

[45] Mitchell Rebuttal at 10:14–16.
[46] Minn. Stat. § 216B.45.

– where Slayton will pay to purchase the Company's distribution system, and also continue to pay its share of shared distribution costs for a period of time.

Similarly, the Commission has decided several lost revenue cases related to the expansion of existing municipal utilities in the past. I am not aware of any case in which the Commission concluded that the purchase of distribution assets prohibited the utility from recovering lost revenue related to the shared costs of the distribution system. In fact, the Commission rejected a similar argument in one case. In *City of Olivia*, a trade organization argued that the lost revenue factor was duplicative of the value of property factor. The Commission rejected that argument and explained that each factor must be given consideration on its own.[47]

That said, I do agree that when Slayton exits the system, the distribution system will be slightly smaller, and that adjustment was already included in my Direct Testimony.[48]

6. Customer Avoided Costs

Q. WHAT IS THE CITY'S RECOMMENDATION FOR CUSTOMER COSTS?

A. The City does not clearly state a recommendation for customer costs, but appears to maintain its original recommendation that customer costs are 100 percent avoidable. City witness Berg argues that the Company will reduce customer costs because it will no longer own the distribution lines in Slayton.

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[47] *In the Matter of the Application of the City of Olivia to Extend its Municipal Electric Service Area into an Area Served by Renville-Sibley Cooperative Power Association*, Docket No. E-288, 136/SA-85-93, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER SETTING COMPENSATION FOR SERVICE EXTENSION at 8 (June 27, 1986).

[48] Peterson Direct at 23:19–24.

Q. WHY ARE DISTRIBUTION COSTS INCLUDED IN THE CUSTOMER COST CATEGORY?

A. The customer cost category includes costs related to meters and service drops because that is how they are grouped for purposes of the CCOSS. As noted in my Direct Testimony, I have treated these costs as avoidable.[49]

Q. DO YOU AGREE WITH CITY WITNESS BERG THAT THE COMPANY WILL REDUCE COSTS AFTER SLAYTON EXITS THE SYSTEM?

A. No. City witness Berg is arguing about the shared costs for maintaining the entire distribution system for all of the Company's customers. When Slayton exits the system, it will no longer contribute to these shared costs.

Further, as I previously explained, "[t]he Company does not expect to reduce the budget for customer service or back-office support. The Company will continue to incur the same amount of cost for these functions if Slayton exits the system, and as a result they will not be avoided."[50] The Company has not identified any costs that will be reduced.[51] Neither has Slayton.

I also agree with the Rebuttal Testimony of Department witness Ngo, who explained that "Clearly variable O&M expenses that can be shown to decrease when Slayton leaves . . .; and any demonstrable reductions in customer service or billing costs attributable to the loss of Slayton's accounts" should be treated as avoidable.[52] In this case, the City has not identified any costs that "can be

[49] Peterson Direct at 22:14–16.
[50] Peterson Direct at 22:1–6.
[51] For a different community, this analysis could lead to a different result.
[52] Ngo Rebuttal at 9:17–10:2.

shown to decrease" or made any demonstration of reductions in either customer service or billing costs. As a result, I continue to recommend that 27.1 percent of customer costs are avoidable.

7. Relevant Time Period

Q. WHAT IS THE CITY'S RECOMMENDATION FOR A LOST REVENUE TIME PERIOD?

A. The City continues to recommend a lost revenue time period of five years.

Q. HAS THE COMMISSION EVER SET A TIME PERIOD OF FIVE YEARS IN THE PAST?

A. No. As noted by Department witness Ngo, the Commission has traditionally used a ten-year relevant time period when setting a lost revenue time period for distribution cooperatives.[53]

Q. ARE YOU AWARE OF ANY OTHER JURISDICTIONS THAT HAVE APPLIED A FIVE-YEAR LOST REVENUE TIME PERIOD?

A. While I have not performed an exhaustive search, I am not aware of any other jurisdiction that have applied a five-year lost revenue time period.

Q. WHAT LOST REVENUE TIME PERIODS HAVE OTHER JURISDICTIONS APPLIED?

A. As described in my Direct Testimony, FERC has decided two lost revenue cases. The lost revenue time period in those cases were 20 years and 15 years based primarily on the utility's planning horizon for generation assets.[54]

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[53] Ngo Rebuttal at 8:3–6.
[54] Peterson Direct at 15:13–16:14.

City witness Berg argues that these cases are not relevant because they are 25 years old and the context was different.[55] While I do not dispute the age of these cases, they are the only regulatory proceedings that I am aware of in which a regulator has assessed the appropriate time period for recovering lost revenues related to generation assets. Contrary to City witness Berg's argument, these are likely the *most* relevant cases when evaluating the lost revenue time period.

Q. WHY DOES CITY WITNESS BERG DISAGREE WITH YOUR ANALYSIS OF PLANNING HORIZONS?

A. City witness Berg focuses almost entirely on the Company's ability to adjust planning in the future, but that is not the correct analysis.

In the past, the Company made investment decisions based on the assumption that Slayton would remain on the system, and would contribute to the costs of the investments for the duration of the relevant planning horizon. If Slayton does not pay its share of the costs, then rates for other customers will increase. The cost shift from Slayton to other customers for existing investments will take place regardless of what happens in future planning periods.

It is appropriate to look at planning horizons because those planning horizons formed the basis of the investment decisions that have resulted in current rates and revenues. For generation resources, the Company evaluated the needs of customers 30 years in the future and developed resource plans to meet those needs. That analysis included the expectation that Slayton would be part of the system and would contribute to system costs. City witness Berg's focus on what

[55] Berg Rebuttal at 22:8–16.

the Company can do in the future is a red herring because nothing that happens in the next IRP planning cycle will change the costs of the generation that is already built.

Q. IS THE COMPANY'S ANALYTICAL FRAMEWORK CONSISTENT WITH OTHER REGULATIONS?

A. Yes. Specifically, the Company's analytical framework is consistent with the FERC rules related to recovery of lost revenues for stranded generation. The first criteria in determining whether lost revenues can be recovered requires the utility to demonstrate that "[i]t incurred costs to provide service to a . . . retail customer based on a reasonable expectation that the utility would continue to serve the customer."[56] The Company made a series of investment decisions based on the reasonable assumption that it would continue to provide service in Slayton, and that Slayton would continue to contribute to the shared costs of the system. That is why the time period for making those investment decisions is relevant to the lost revenue time period.

Q. WHAT IS YOUR RECOMMENDATION FOR THE LOST REVENUE TIME PERIOD?

A. I continue to recommend a lost revenue time period of 20 years. While the revenues from Slayton will be lost forever, a 20-year time period reasonably protects our customers from increased costs related to the loss of revenue from Slayton.

B. Integration Costs

Q. WHAT DID THE COMPANY RECOMMEND REGARDING INTEGRATION EXPENSES?

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[56] 18 C.F.R § 35.26(c)(2)(1).

A. In my Direct Testimony, I identified the potential for integration expenses related to: 1) meter integration expense; 2) continued service expense, for system modifications to continue to provide service to Xcel Energy customers located outside Slayton, and 3) DER integration expense related to assisting customers participating in DER programs, and for engineering studies and resulting upgrades that could result if Slayton exits the system.[57]

In my Rebuttal Testimony, I provided additional information about DER integration expense, related to the timing and impact of Slayton's exit on projects currently in the interconnection queue near Slayton.[58]

1. Meter Integration Expense

Q. WHAT IS THE CITY'S RECOMMENDATION REGARDING METER INTEGRATION EXPENSE?

A. City witness Berg suggests that our cost estimate of $140,000 for meter integration expense is high, and that it may be possible for the City to do the work at a reduced cost.[59] City witness Berg also argues that the meter integration expense should be reduced to "reflect the value of these meters to Xcel."[60]

Q. WHAT IS YOUR RESPONSE REGARDING METER INTEGRATION EXPENSE?

A. I want to clarify that the Company is not asking to recover $140,000 in just compensation from Slayton based on this preliminary cost estimate. As indicated in my Direct Testimony, the Company does not know how much it

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[57] Peterson Direct at 31:24–39:12.
[58] Peterson Rebuttal at 38:4–41:26.
[59] Berg Rebuttal at 30:4–7.
[60] *Id.* at 30:7–8.

will cost to remove the meters in Slayton because the Company has never completed a project like this before.[61] The Company anticipates that it will use a Request for Pricing process to solicit bids from contractors, but does not have a reliable estimate for what the costs will be. The Company proposes that Slayton pay just compensation based on the actual costs for removing the meters once those costs are known.

The Company also fully intends to coordinate with the City of Slayton in removing the meters. As I explained in my Direct Testimony, coordination is essential because new meters for Slayton will need to be installed immediately after Xcel Energy meters are removed – without that close coordination, customers would be without electricity.[62] If this coordination with Slayton can result in a lower cost, that would reduce the amount that Slayton pays in just compensation. The Company commits to working collaboratively with the City to complete this work with the lowest reasonable cost.

Q. DO YOU AGREE THAT THE COST OF METER INTEGRATION EXPENSE SHOULD BE REDUCED BASED ON THE VALUE OF THE METERS?

A. No. Xcel Energy already owns the meters in question, and we do not anticipate any cost savings for continuing to own them. They are included in the Company's rate base. The meter replacement is not happening because Xcel Energy wants the meters back, it is happening because Slayton has decided it wants to use different meters. If Slayton would, instead, prefer to purchase the meters from Xcel Energy, then this integration expense could likely be avoided.

[61] Peterson Direct at 33:11–14.
[62] *Id.* at 32:23–33:2.

Q. HAS THE COMPANY IDENTIFIED ANY FURTHER ISSUES THAT WOULD IMPACT THE COST OF METER REMOVAL?

A. Yes. The Company operates a CIP program called Saver's Switch, in which customers receive a rate discount in return for allowing the Company to curtail the use of their air conditioners at certain times. This program requires the installation of Xcel Energy technology on the customer's air conditioner. The Company has identified 494 customer premises in Slayton where a Saver's Switch is installed.

When the Company removes meters from customer homes, the Company intends to disconnect and remove Saver's Switch hardware as well. As discussed above, the Company proposes to collect only actual costs for integration expense and proposes that the cost to remove any Saver's Switches in Slayton be included in just compensation.

2. Continued Service Integration Expense

Q. WHAT IS THE CITY'S RECOMMENDATION REGARDING CONTINUED SERVICE INTEGRATION EXPENSE?

A. City witness Berg does not raise any concerns regarding the estimated cost of continued service integration expense.[63] I confirm that the Company intends only to recover actual costs for this work as just compensation from Slayton, and will coordinate with the City to minimize expense and provide documentation of actual costs.

[63] Berg Rebuttal at 30:10–12.

3. DER Integration Expense

Q. WHAT IS THE CITY'S RECOMMENDATION REGARDING DER INTEGRATION EXPENSE?

A. Through the testimony of City witnesses Berg and Mitchell, the City argues that system safety and stability concerns are not an issue if Slayton exits the system, that the City should not pay for engineering studies required to evaluate the impact of its exit on the safety and reliability of the system and upgrades identified by the studies, and that the Company should be required to transfer its property to the City before completing upgrades to ensure that the system is safe after the transfer.[64]

Q. WHAT IS YOUR RESPONSE REGARDING DER INTEGRATION EXPENSE?

A. As I noted above, I agree with Department witness Ngo that "Slayton-specific integration expenses, such as removal or relocation of equipment, necessary system reconfiguration, and related engineering" should be included in just compensation when they are "clearly caused by the transfer."[65] The Company does not propose to include estimated, speculative costs in just compensation. The Company proposes that Slayton should be required to pay for the actual cost of any required engineering studies, and any upgrades identified by those studies that are necessary to maintain safety and reliability after Slayton exits the system.

Q. DO YOU AGREE WITH CITY WITNESS MITCHELL THAT THERE ARE NO SYSTEM STABILITY CONCERNS?

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[64] Berg Rebuttal at 31:8–19; Mitchell Rebuttal at 12:13–13:16.
[65] Ngo Rebuttal at 12:7–11.

A. No. As described in MISO's Business Practices Manual 015 - Generation Interconnection, MISO requires a transmission study, called a DER Affected System Study (AFS) when the aggregate DER exceeds the substation Peak Load by at least 1 MW.[66] Once this threshold has been met at a substation, performance of a MISO DER AFS is mandatory.

When DER generation at the substation level exceeds daytime minimum load (DML), but does not meet the threshold for a MISO DER AFS study, then an Xcel Energy internal transmission study (ITS) needs to be performed. This ITS process was explained in detail in a recent compliance filing in in Docket No. 16-521.[67] The Commission is evaluating the ITS in a working group.[68]

If Slayton exits the system, there will be more DER generation than customer load on the SLW substation. This will almost certainly trigger either an Xcel Energy ITS or a MISO DER AFS, which must be completed in order to ensure that the transmission system remains safe and reliable.

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[66] MISO, Generation Interconnection Business Practices Manual at 136–137 (Dec. 15, 2025), available at https://www.misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals/ The Commission recently recognized this requirement. *In the Matter of a Formal Complaint and Petition for Relief by SunShare LLC Against Northern States Power Co. d/b/a Xcel Energy Regarding Settlement Agreements*, Docket No. E002/C-25-76, ORDER DISMISSING COMPLAINT at 2 (June 12, 2025) ("when the aggregate DER on a system is greater than the system's peak load, MISO requires a DER Affected System Study (DER AFS)").

[67] *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established Under Minn. Stat. § 216B.1611*, Docket No. E999/CI-16-521, XCEL ENERGY COMPLIANCE FILING (Oct. 1, 2025).

[68] *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established Under Minn. Stat. § 216B.1611*, Docket No. E999/CI-16-521, ORDER REFERRING REVIEW OF XCEL'S INTERNAL TRANSMISSION STUDY PROCESS TO THE DISTRIBUTED GENERATION WORKING GROUP (Sept. 10, 2025).

Further, distribution studies will also be necessary. In addition to the transmission studies, Xcel Energy conducts distribution studies to evaluate risks including imbalances, power quality issues, reliability concerns, and equipment overloads. Moving forward without completing this work could result in safety and reliability issues.

It is possible that the Distribution, ITS or MISO DER AFS studies will indicate that no upgrades are needed, as City witness Mitchell seems to believe. If that is the case, then the City will be responsible only for the costs of the studies themselves. But if upgrades are identified, then both the cost of the studies and the upgrades should be included in just compensation.

Q. WOULD IT BE REASONABLE TO MOVE FORWARD WITHOUT CONDUCTING ANY ENGINEERING STUDIES?

A. No, and I am surprised that the City would suggest that. It seems obvious that disconnecting an entire city from our system would require engineering studies to make sure the disconnection does not cause any problems on the electrical grid. Moving forward without conducting these studies and completing any necessary work that is identified would be irresponsible.

Q. DO YOU AGREE WITH CITY WITNESS BERG'S STATEMENT THAT THE CITY SHOULD NOT HAVE TO PAY FOR ENGINEERING STUDIES?

A. No. The cost of these transmission and distribution studies, and any system upgrades that are needed to maintain both transmission and distribution system reliability, stability, power quality and safety, will be caused by Slayton and should be included in just compensation as an integration expense.

As with other integration expense items, I clarify that the Company proposes to recover actual costs from Slayton, and will provide documentation of actual costs to Slayton upon request. The Company does not have a preliminary cost estimate at this time, and does not intend to begin engineering studies until they are paid for by Slayton.

Q. DO YOU AGREE WITH CITY WITNESS BERG'S STATEMENT THAT IT WOULD BE UNREASONABLE TO DELAY THE PROPOSED PURCHASE UNTIL ALL STUDIES AND UPGRADES HAVE BEEN COMPLETED?

A. No. These studies are needed to ensure safety and reliability for Xcel Energy's continuing customers, and the customers who live in Slayton. The Company will not complete the transfer until it has confirmed that it can do so safely and reliably, and in compliance with any requirements (either internal or from MISO) for the transmission and distribution engineering studies and system upgrades. If any required upgrades are identified, the Company will not complete the transfer until the upgrades have been completed and paid for by Slayton.

Q. WHAT IS THE TIMELINE FOR MAKING SYSTEM UPGRADES?

A. I am not a practicing engineer and am not involved in purchasing system upgrade equipment. I am generally aware, though, that some types of utility equipment can take a long time to obtain given the supply chain impacts of high demand and tariffs. The Company does not intend to order equipment needed for the upgrades for this area until 1) engineering studies have been paid for and completed, and 2) any required system upgrade equipment identified in these studies has been paid for. If Slayton is concerned about the timing of the purchase, one option to accelerate the process is for Slayton to pay for the engineering studies now and not wait until the conclusion of this case. The Company is open to discussing that possibility with the City.

Q. DID THE CITY PROVIDE A RESPONSE REGARDING THE DER INTEGRATION IMPACT ON PROJECTS CURRENTLY IN THE INTERCONNECTION QUEUE?

A. No, these issues were identified as the Company continued to explore the issue and were included in my Rebuttal Testimony. The Company proposes that any DER integration expenses related to DER projects in the interconnection queue be handled in a similar way as other DER integration expenses.

Q. DO YOU HAVE ANY FURTHER ANALYSIS REGARDING INTEGRATION EXPENSE?

A. Yes. The Company recognizes that municipalities have the legal right to take property from incumbent utilities to form a municipal utility. But state law requires those utilities to pay just compensation. If Slayton's exit requires upgrades to ensure safety and reliability, then those costs are caused by Slayton and should be included in just compensation. If the costs are not paid for by Slayton, they will have to be included in rates for our other customers. Slayton's decision to exit the system should not result in increased costs to our other customers.

C. Stranded Costs

Q. WHAT IS THE CITY'S RECOMMENDATION REGARDING STRANDED COSTS FOR THE SLW SUBSTATION?

A. City witness Berg disagrees that the net book value of SLW should be included in just compensation.

Q. WHAT IS THE BASIS OF CITY WITNESS BERG'S ARGUMENT?

A. City witness Berg makes a few arguments in support of his position. First, City witness Berg argues that Slayton is not a stranded asset because the substation capacity is greater than the load from Slayton.[69] Second, City witness Berg argues that the substation should not be included in just compensation because it will be used to interconnect Community Solar Gardens (CSGs) in the Slayton area to Xcel Energy's system.[70] Third, City witness Berg argues that he has already accounted for the SLW substation in his lost revenue calculation.[71]

In addition, City witness Berg identifies some typographical errors in my Direct Testimony, which I appreciate and clarify below.

Q. IS CITY WITNESS BERG'S ARGUMENT CONSISTENT WITH HIS PRIOR TESTIMONY?

A. No. In his Direct Testimony, City witness Berg testified that the SLW substation would "represent a stranded cost for Xcel."[72] Despite this testimony, City witness Berg now argues that the Company should not recover the costs of the stranded asset that is being created by the City.

Q. DO YOU AGREE WITH THE ANALYSIS COMPARING SUBSTATION CAPACITY TO SLAYTON LOAD?

A. No. First, City witness Berg is incorrect that load at SLW is 4 MW. In his Direct Testimony, City witness Berg attached an Xcel Energy Information Request 13, in which the Company explained that the "net peak demand" for SLW was 4.3

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[69] Berg Rebuttal at 33:26–34:2.
[70] Berg Rebuttal at 34:10–35:2.
[71] Berg Rebuttal at 35:12–13.
[72] Berg Direct at 28:14.

MW in 2024.[73] "Net peak demand" means the demand of Slayton customers, the small handful of customers outside Slayton, minus the production from the local CSGs. The CSGs connected to the system have a nameplate generation capability of several MWs. If the Company had made use of a substation with only 4 MVA of capacity, customers in Slayton would have experienced significant service interruptions.

Second, the Company does not plan for substations that barely meet capacity requirements for customers. It is important that substations have at least some amount of excess capacity to ensure the safety and reliability of the system and to allow for load growth in a reasonable timeframe. When the Company constructed SLW, it selected one of the standard substation sizes, which ended up being 14 MVA.

Third, City witness Berg may not have all of the information about why the SLW substation was constructed. While it is true that the Company designed a substation with 14 MVA of capacity instead of a smaller size, the SLW substation was also designed with the goal of increasing voltage in the Slayton area. As I explained in my Rebuttal Testimony, the SLW upgrade increased voltage in the Slayton area from 4kV to 13.8kV, which allows the Company to provide higher quality electric service to customers in the Slayton area. As I stated in my Rebuttal Testimony, "[t]he Company did not select a 14MVA substation to provide extra capacity for DERs. It was selected because that is the next standard size of equipment."[74] Ultimately, the SLW substation was

[73] Berg Direct at 29:5–6, PDF page 148 (Xcel Energy response to City of Slayton Information Request 13).
[74] Peterson Rebuttal at 45:1–2.

built to provide service to Slayton, not CSGs, and would not have been built if Slayton was not part of Xcel Energy's system.

Q. DO YOU AGREE WITH THE ARGUMENT THAT SLW IS NOT STRANDED BECAUSE IT WILL BE USED TO CONNECT CSGS?

A. No. First, the SLW substation was not designed to serve CSGs. The law requiring Xcel Energy to create a CSG program was passed in 2013, around six years after the SLW substation was designed and constructed. The SLW substation was designed to meet the needs of customers in the Slayton area at that time and in the foreseeable future. Nearly all of these customers live in Slayton and would no longer be customers after the transfer.

Second, Xcel Energy does not "plan" CSGs as City witness Berg suggests.[75] CSGs are developed by third-party developers who propose to interconnect to the Company's system. The Company is required by state and federal law to allow the interconnection and purchase the power generated by the DERs. The CSGs that are currently proposed could be canceled at the sole discretion of the developers. The Company has no way of knowing or planning when or where CSGs will be proposed.

Third, City witness Berg does not understand that when DERs are involved there are important distinctions about who pays for system components. When the Company builds substations to serve retail customers, those costs are

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[75] Berg Rebuttal at 34:11–12 ("Xcel, as I referenced in my direct testimony, has plans for additional CSGs at that location.").

included in rates. Retail customers should not have to pay for substations that are not used to provide retail service.

That is consistent with how DERs are developed and paid for. The Company does not intend to build a substation just to serve CSGs. Hypothetically, if a CSG developer wanted a new substation constructed and the Company agreed to do so, the CSG developer would be required to pay for the entire cost of the project. To the extent a substation was upgraded to be used by CSGs, retail customers would be protected from the upfront costs.

Applied to this scenario, Slayton's decision to exit the system means that there will be a substation that is used almost entirely to serve CSGs. It is not reasonable for the costs of that substation to be included in rates, and so the costs should be included in just compensation.

Q. DO YOU AGREE WITH THE ARGUMENT THAT CITY WITNESS BERG HAS ACCOUNTED FOR THE SLW SUBSTATION IN HIS LOST REVENUE CALCULATION?

A. No. As City witness Berg explains, he has included only $430,525 in costs for the SLW substation in the lost revenue calculation.[76] That revenue, though, is not directly related to the SLW substation but is Slayton's share of all of the substations on the system. Even if it were directly related to Slayton, City witness Berg's figure represents only 37 percent of the net book value of SLW.[77] The remaining costs of the substation would continue to be paid for by our other customers.

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[76] Berg Direct at 35:14–20.
[77] The net book value of SLW is $1,145,319. Peterson Direct at 41:18.

I also disagree with City witness Berg's argument that an adjustment to lost revenue is the correct way to deal with stranded assets. The lost revenues discussed above represent Slayton's share of shared cost of Xcel Energy's system, and are not specifically tied to the SLW substation. To use a hypothetical example, if Slayton customers were contributing one percent of total revenues and costs, they would be paying for approximately one percent of the costs related to the SLW substation. The lost revenue calculation can be used to account for that one percent, but there still needs to be an adjustment for the rest of the stranded costs. I agree with Department witness Ngo that stranded assets should be analyzed under the "other appropriate factors" part of the just compensation test, and not under lost revenue.[78]

That said, I agree with City witness Berg that it is important to avoid double counting. That is why I removed the costs of the SLW substation from the lost revenue calculation, as explained in my Direct Testimony.[79] This ensures that there are no double counted costs.

Q. WHAT IS YOUR RESPONSE TO CITY WITNESS BERG'S TESTIMONY ABOUT TYPOGRAPHICAL ERRORS IN YOUR DIRECT TESTIMONY?

A. I appreciate that the City has pointed these out, and will correct them with an errata.

[78] Ngo Rebuttal at 13:7–18.

[79] Peterson Direct at 23:21-23 (removing SLW substation costs from the lost revenue calculation).

IV. OVERALL RECOMMENDATION ON JUST COMPENSATION

Q. DO YOU HAVE AN UPDATED RECOMMENDATION FOR JUST COMPENSATION?

A. Yes, I do. This recommendation incorporates the updates I have agreed to related to lost revenues.

Q. HAVE YOU PREPARED A SCHEDULE FOR THE UPDATED LOST REVENUE CALCULATION?

A. Yes. I am providing an updated lost revenue calculation as Schedule 1 to my Surrebuttal Testimony. This lost revenue calculation has been updated to reflect two changes that I have agreed to: 1) transmission costs are treated as 100 percent avoidable; 2) $18,700 in CIP rebates paid to customers who live in Slayton are treated as avoidable.

This update results in a lost revenue lump sum payment of $34,710,977. If converted to a scheduled annual payment, it would be $3,153,021 for twenty years.

Q. WHAT IS YOUR OVERALL RECOMMENDATION REGARDING JUST COMPENSATION?

A. I provide an update of the table from my Direct Testimony.

Table 1
Xcel Energy Surrebuttal Just Compensation Recommendation

Value of Property	$3,220,653
Loss of Revenue*	$34,710,977
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	**$39,217,984**

*or $3,153,021 per year for twenty years

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

	Res	Non-Dmd	Demand	Ltg	Total
Total Rev in 2025	$1,463,026	$268,047	$1,181,452	$1,696	$2,914,221
Avoided Costs in 2025	$434,051	$81,458	$373,040	$456	$889,005
Lost Rev Value in 2025	$1,028,975	$186,589	$808,412	$1,240	**$2,025,216**

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Total Revenues					**Lost Revenues**								
Year	Year No.	Res	Non-Dmd	Demand	Ltg	Total	Res	Non-Dmd	Demand	Ltg	Total	**Levelized Payment**	Annual Sales kWh	Rate Mills/kWh	Estimated Annual Pymt
2025															
2026	1	$1,552,828	$277,281	$1,222,154	$1,760	$3,054,023	$1,092,135	$193,017	$836,263	$1,286	$2,122,701	$3,153,021	20,822,111	125.13	2,605,528
2027	2	$1,648,143	$286,834	$1,264,258	$1,826	$3,201,061	$1,159,171	$199,666	$865,072	$1,335	$2,225,244	$3,153,021	21,165,391	125.13	2,648,484
2028	3	$1,749,308	$296,716	$1,307,812	$1,894	$3,355,730	$1,230,323	$206,545	$894,875	$1,385	$2,333,128	$3,153,021	21,514,645	125.13	2,692,187
2029	4	$1,856,683	$306,938	$1,352,867	$1,965	$3,518,453	$1,305,842	$213,660	$925,704	$1,437	$2,446,643	$3,153,021	21,870,002	125.13	2,736,654
2030	5	$1,970,648	$317,512	$1,399,474	$2,039	$3,689,673	$1,385,996	$221,021	$957,595	$1,491	$2,566,103	$3,153,021	22,231,599	125.13	2,781,901
2031	6	$2,091,609	$328,450	$1,447,687	$2,116	$3,869,862	$1,471,070	$228,636	$990,584	$1,547	$2,691,837	$3,153,021	22,599,574	125.13	2,827,947
2032	7	$2,219,994	$339,766	$1,497,561	$2,195	$4,059,516	$1,561,366	$236,512	$1,024,711	$1,605	$2,824,194	$3,153,021	22,974,068	125.13	2,874,809
2033	8	$2,356,260	$351,471	$1,549,153	$2,277	$4,259,161	$1,657,204	$244,660	$1,060,013	$1,665	$2,963,542	$3,153,021	23,355,225	125.13	2,922,504
2034	9	$2,500,890	$363,579	$1,602,522	$2,363	$4,469,354	$1,758,926	$253,089	$1,096,531	$1,727	$3,110,273	$3,153,021	23,743,194	125.13	2,971,051
2035	10	$2,654,398	$376,105	$1,657,730	$2,452	$4,690,685	$1,866,891	$261,808	$1,134,307	$1,792	$3,264,798	$3,153,021	24,138,126	125.13	3,020,470
2036	11	$2,817,328	$389,062	$1,714,839	$2,544	$4,923,773	$1,981,483	$270,827	$1,173,384	$1,859	$3,427,553	$3,153,021	24,540,176	125.13	3,070,780
2037	12	$2,990,259	$402,465	$1,773,917	$2,639	$5,169,280	$2,103,109	$280,157	$1,213,808	$1,929	$3,599,003	$3,153,021	24,949,503	125.13	3,122,000
2038	13	$3,173,805	$416,330	$1,835,029	$2,738	$5,427,902	$2,232,200	$289,809	$1,255,625	$2,002	$3,779,636	$3,153,021	25,366,270	125.13	3,174,151
2039	14	$3,368,617	$430,673	$1,898,247	$2,841	$5,700,378	$2,369,215	$299,793	$1,298,882	$2,077	$3,969,967	$3,153,021	25,790,642	125.13	3,227,254
2040	15	$3,575,387	$445,510	$1,963,643	$2,948	$5,987,488	$2,514,640	$310,121	$1,343,629	$2,155	$4,170,545	$3,153,021	26,222,791	125.13	3,281,330
2041	16	$3,794,849	$460,858	$2,031,292	$3,058	$6,290,057	$2,668,992	$320,805	$1,389,918	$2,236	$4,381,951	$3,153,021	26,662,890	125.13	3,336,401
2042	17	$4,027,781	$476,735	$2,101,271	$3,173	$6,608,960	$2,832,818	$331,857	$1,437,801	$2,319	$4,604,795	$3,153,021	27,111,117	125.13	3,392,489
2043	18	$4,275,011	$493,159	$2,173,661	$3,292	$6,945,123	$3,006,700	$343,290	$1,487,334	$2,407	$4,839,731	$3,153,021	27,567,656	125.13	3,449,617
2044	19	$4,537,416	$510,148	$2,248,545	$3,416	$7,299,525	$3,191,255	$355,116	$1,538,574	$2,497	$5,087,442	$3,153,021	28,032,693	125.13	3,507,808
2045	20	$4,815,929	$527,723	$2,326,009	$3,544	$7,673,205	$3,387,138	$367,350	$1,591,579	$2,591	$5,348,658	$3,153,021	28,506,420	125.13	3,567,087
2046															
2047															
2048															
2049															
Total		$53,161,214	$7,269,592	$32,041,662	$47,536	$92,520,004	$37,389,336	$5,060,389	$21,924,610	$34,751	$64,409,086	$63,060,426			

Total Revenue $92,520,004

Total Lump Sum Payment $34,710,977

Value of Levelized Payments $34,710,977

Value of Mill Rate Payments $34,685,041

Average Annual Use per Customer (kWh)	9,205
Average Annual Revenue per Customer	$1,490
Number of Customers	982
Total Revenue in 2025	$1,463,026
Avoided Costs in 2025	$434,051
Lost Revenue Value in 2025	$1,028,975

(a) Year	(b) Existing Customer Sales Growth	(c) Customer Additions	(d) Utility Price Growth	(e) Annual Change Factor	(f) Year No.	(g) Total Revenue	(h) Lost Revenue	(i) Discount Rate	(j) **Discounted Lost Revenue**	(k) **Levelized Payment**	(l) Annual Sales kWh	(m) Rate Mills/kWh	(n) Estimated Annual Pymt
2025	1.000	1.000	1.000	1.000									
2026	1.024	1.007	1.029	1.061	1	$1,552,828	$1,092,135	1.0651	$1,025,372	$1,802,135	9,319,174	154.02	$1,435,362
2027	1.049	1.014	1.059	1.127	2	$1,648,143	$1,159,171	1.1345	$1,021,781	$1,802,135	9,605,031	154.02	$1,479,391
2028	1.074	1.021	1.091	1.196	3	$1,749,308	$1,230,323	1.2083	$1,018,203	$1,802,135	9,896,666	154.02	$1,524,309
2029	1.100	1.028	1.122	1.269	4	$1,856,683	$1,305,842	1.2870	$1,014,638	$1,802,135	10,194,209	154.02	$1,570,137
2030	1.126	1.035	1.155	1.347	5	$1,970,648	$1,385,996	1.3708	$1,011,085	$1,802,135	10,497,795	154.02	$1,616,896
2031	1.153	1.043	1.189	1.430	6	$2,091,609	$1,471,070	1.4601	$1,007,544	$1,802,135	10,807,560	154.02	$1,664,607
2032	1.181	1.050	1.224	1.517	7	$2,219,994	$1,561,366	1.5551	$1,004,016	$1,802,135	11,123,647	154.02	$1,713,292
2033	1.209	1.057	1.260	1.611	8	$2,356,260	$1,657,204	1.6564	$1,000,500	$1,802,135	11,446,198	154.02	$1,762,972
2034	1.238	1.065	1.297	1.709	9	$2,500,890	$1,758,926	1.7642	$996,997	$1,802,135	11,775,360	154.02	$1,813,670
2035	1.268	1.072	1.335	1.814	10	$2,654,398	$1,866,891	1.8791	$993,505	$1,802,135	12,111,285	154.02	$1,865,410
2036	1.298	1.080	1.374	1.926	11	$2,817,328	$1,981,483	2.0014	$990,026	$1,802,135	12,454,127	154.02	$1,918,216
2037	1.329	1.087	1.414	2.044	12	$2,990,259	$2,103,109	2.1318	$986,560	$1,802,135	12,804,044	154.02	$1,972,111
2038	1.361	1.095	1.456	2.169	13	$3,173,805	$2,232,200	2.2706	$983,105	$1,802,135	13,161,198	154.02	$2,027,120
2039	1.394	1.103	1.498	2.302	14	$3,368,617	$2,369,215	2.4184	$979,662	$1,802,135	13,525,753	154.02	$2,083,270
2040	1.427	1.110	1.542	2.444	15	$3,575,387	$2,514,640	2.5759	$976,231	$1,802,135	13,897,881	154.02	$2,140,586
2041	1.462	1.118	1.587	2.594	16	$3,794,849	$2,668,992	2.7436	$972,813	$1,802,135	14,277,753	154.02	$2,199,095
2042	1.497	1.126	1.634	2.753	17	$4,027,781	$2,832,818	2.9222	$969,406	$1,802,135	14,665,548	154.02	$2,258,824
2043	1.532	1.134	1.682	2.922	18	$4,275,011	$3,006,700	3.1125	$966,012	$1,802,135	15,061,447	154.02	$2,319,802
2044	1.569	1.142	1.731	3.101	19	$4,537,416	$3,191,255	3.3151	$962,629	$1,802,135	15,465,637	154.02	$2,382,056
2045	1.607	1.150	1.782	3.292	20	$4,815,929	$3,387,138	3.5310	$959,258	$1,802,135	15,878,308	154.02	$2,445,617
2046	1.646	1.158	1.834	3.494									
2047	1.685	1.166	1.888	3.708									
2048	1.725	1.174	1.943	3.936									
2049	1.767	1.182	2.000	4.177									
						$57,977,143	$40,776,474		$19,839,344	$36,042,704	247,968,620		$38,192,745

Total Lump Sum Payment $\boxed{\$19,839,344}$

Value of Levelized Payments $\boxed{\$19,839,344}$

Value of Mill Rate Payments $\boxed{\$19,839,344}$

Average Annual Use per Customer (kWh)	10,359
Average Annual Revenue per Customer	1,514
Number of Customers	177
Total Revenue in 2025	$268,047
Avoided Costs in 2025	$81,458
Lost Revenue Value in 2025	$186,589

(a) Year	(b) Existing Customer Sales Growth	(c) Customer Additions	(d) Utility Price Growth	(e) Overall Factor	(f) Year No.	(g) Total Revenue	(h) **Lost Revenue**	(i) Discount Rate	(j) **Discounted Lost Revenue**	(k) **Levelized Payment**	(l) Annual Sales kWh	(m) Rate Mills/kWh	(n) Estimated Annual Pymt
2025	1.000	1.000	1.000	1.000									
2026	1.001	1.004	1.029	1.034	1	$277,281	$193,017	1.0651	$181,218	$253,002	1,842,647	132.29	$243,763
2027	1.002	1.008	1.059	1.070	2	$286,834	$199,666	1.1345	$176,001	$253,002	1,851,845	132.29	$244,980
2028	1.003	1.012	1.091	1.107	3	$296,716	$206,545	1.2083	$170,935	$253,002	1,861,075	132.29	$246,201
2029	1.004	1.016	1.122	1.145	4	$306,938	$213,660	1.2870	$166,014	$253,002	1,870,336	132.29	$247,426
2030	1.005	1.020	1.155	1.185	5	$317,512	$221,021	1.3708	$161,235	$253,002	1,879,629	132.29	$248,655
2031	1.006	1.024	1.189	1.225	6	$328,450	$228,636	1.4601	$156,594	$253,002	1,888,954	132.29	$249,889
2032	1.007	1.028	1.224	1.268	7	$339,766	$236,512	1.5551	$152,086	$253,002	1,898,310	132.29	$251,126
2033	1.008	1.032	1.260	1.311	8	$351,471	$244,660	1.6564	$147,708	$253,002	1,907,698	132.29	$252,368
2034	1.009	1.037	1.297	1.356	9	$363,579	$253,089	1.7642	$143,456	$253,002	1,917,118	132.29	$253,614
2035	1.010	1.041	1.335	1.403	10	$376,105	$261,808	1.8791	$139,327	$253,002	1,926,570	132.29	$254,865
2036	1.011	1.045	1.374	1.451	11	$389,062	$270,827	2.0014	$135,316	$253,002	1,936,055	132.29	$256,120
2037	1.012	1.049	1.414	1.501	12	$402,465	$280,157	2.1318	$131,420	$253,002	1,945,572	132.29	$257,379
2038	1.013	1.053	1.456	1.553	13	$416,330	$289,809	2.2706	$127,638	$253,002	1,955,121	132.29	$258,642
2039	1.014	1.057	1.498	1.607	14	$430,673	$299,793	2.4184	$123,963	$253,002	1,964,703	132.29	$259,909
2040	1.015	1.062	1.542	1.662	15	$445,510	$310,121	2.5759	$120,395	$253,002	1,974,318	132.29	$261,181
2041	1.016	1.066	1.587	1.719	16	$460,858	$320,805	2.7436	$116,929	$253,002	1,983,965	132.29	$262,458
2042	1.017	1.070	1.634	1.779	17	$476,735	$331,857	2.9222	$113,563	$253,002	1,993,646	132.29	$263,738
2043	1.018	1.075	1.682	1.840	18	$493,159	$343,290	3.1125	$110,294	$253,002	2,003,360	132.29	$265,023
2044	1.019	1.079	1.731	1.903	19	$510,148	$355,116	3.3151	$107,119	$253,002	2,013,107	132.29	$266,313
2045	1.020	1.083	1.782	1.969	20	$527,723	$367,350	3.5310	$104,036	$253,002	2,022,887	132.29	$267,607
2046	1.021	1.087	1.834	2.037									
2047	1.022	1.092	1.888	2.107									
2048	1.023	1.096	1.943	2.179									
2049	1.024	1.101	2.000	2.254									
						$7,797,315	$5,427,739		$2,785,247	$5,060,037	38,636,916		$5,111,256

Total Lump Sum Payment **$2,785,247**

Value of Levelized Payments **$2,785,247**

Value of Volumetric Payments **$2,785,247**

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Average Annual Use per Customer (kWh)	131,674
Average Annual Revenue per Customer	16,184
Number of Customers	73
Total Revenue in 2025	$1,181,452
Avoided Costs in 2025	$373,040
Lost Revenue Value in 2025	$808,412

(a) Year	(b) Existing Customer Sales Growth	(c) Customer Additions	(d) Utility Price Growth	(e) Overall Factor	(f) Year No.	(g) Total Revenue	(h) Lost Revenue	(i) Discount Rate	(j) Discounted Lost Revenue	(k) Levelized Payment	(l) Annual Sales kWh	(m) Rate Mills/kWh	(n) Estimated Annual Pymt
2025	1.000	1.000	1.000	1.000									
2026	1.001	1.004	1.029	1.034	1	$1,222,154	$836,263	1.0651	$785,142	$1,096,154	9,660,291	109.33	$1,056,125
2027	1.002	1.008	1.059	1.070	2	$1,264,258	$865,072	1.1345	$762,540	$1,096,154	9,708,515	109.33	$1,061,397
2028	1.003	1.012	1.091	1.107	3	$1,307,812	$894,875	1.2083	$740,590	$1,096,154	9,756,904	109.33	$1,066,687
2029	1.004	1.016	1.122	1.145	4	$1,352,867	$925,704	1.2870	$719,271	$1,096,154	9,805,457	109.33	$1,071,995
2030	1.005	1.020	1.155	1.185	5	$1,399,474	$957,595	1.3708	$698,566	$1,096,154	9,854,176	109.33	$1,077,321
2031	1.006	1.024	1.189	1.225	6	$1,447,687	$990,584	1.4601	$678,457	$1,096,154	9,903,060	109.33	$1,082,666
2032	1.007	1.028	1.224	1.268	7	$1,497,561	$1,024,711	1.5551	$658,927	$1,096,154	9,952,111	109.33	$1,088,028
2033	1.008	1.032	1.260	1.311	8	$1,549,153	$1,060,013	1.6564	$639,959	$1,096,154	10,001,329	109.33	$1,093,409
2034	1.009	1.037	1.297	1.356	9	$1,602,522	$1,096,531	1.7642	$621,537	$1,096,154	10,050,715	109.33	$1,098,808
2035	1.010	1.041	1.335	1.403	10	$1,657,730	$1,134,307	1.8791	$603,645	$1,096,154	10,100,270	109.33	$1,104,226
2036	1.011	1.045	1.374	1.451	11	$1,714,839	$1,173,384	2.0014	$586,269	$1,096,154	10,149,994	109.33	$1,109,662
2037	1.012	1.049	1.414	1.501	12	$1,773,917	$1,213,808	2.1318	$569,392	$1,096,154	10,199,887	109.33	$1,115,117
2038	1.013	1.053	1.456	1.553	13	$1,835,029	$1,255,625	2.2706	$553,002	$1,096,154	10,249,951	109.33	$1,120,590
2039	1.014	1.057	1.498	1.607	14	$1,898,247	$1,298,882	2.4184	$537,083	$1,096,154	10,300,186	109.33	$1,126,082
2040	1.015	1.062	1.542	1.662	15	$1,963,643	$1,343,629	2.5759	$521,623	$1,096,154	10,350,592	109.33	$1,131,593
2041	1.016	1.066	1.587	1.719	16	$2,031,292	$1,389,918	2.7436	$506,607	$1,096,154	10,401,171	109.33	$1,137,122
2042	1.017	1.070	1.634	1.779	17	$2,101,271	$1,437,801	2.9222	$492,024	$1,096,154	10,451,923	109.33	$1,142,671
2043	1.018	1.075	1.682	1.840	18	$2,173,661	$1,487,334	3.1125	$477,860	$1,096,154	10,502,849	109.33	$1,148,238
2044	1.019	1.079	1.731	1.903	19	$2,248,545	$1,538,574	3.3151	$464,105	$1,096,154	10,553,949	109.33	$1,153,825
2045	1.020	1.083	1.782	1.969	20	$2,326,009	$1,591,579	3.5310	$450,745	$1,096,154	10,605,225	109.33	$1,159,431
2046	1.021	1.087	1.834	2.037									
2047	1.022	1.092	1.888	2.107									
2048	1.023	1.096	1.943	2.179									
2049	1.024	1.101	2.000	2.254									
						$34,367,671	$23,516,189		$12,067,343	$21,923,087	202,558,557		$22,144,993

Total Lump Sum Payment **$12,067,343**

Value of Levelized Payments **$12,067,343**

Value of Volumetric Payments **$12,067,343**

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
State of Minnesota Electric Jurisdiction
City of Slayton Revenue Summary - Lighting Customers

MPUC Docket No. E002, PT-7157/SA-25-129
CAH Docket No. 22-2500-40870
Exhibit___(LRP-3), Schedule 1

[PROTECTED DATA BEGINS

Average Annual Use per Customer (kWh)	
Average Annual Revenue per Customer	
Number of Customers	

PROTECTED DATA ENDS}

Total Revenue in 2025	$1,696
Avoided Costs in 2025	$456
Lost Revenue Value in 2025	$1,240

(a) Year	(b) Existing Customer Sales Growth	(c) Customer Additions	(d) Utility Price Growth	(e) Overall Factor	(f) Year No.	(g) Total Revenue	(h) **Lost Revenue**	(i) Discount Rate	(j) **Discounted Lost Revenue**	(k) **Levelized Payment**	(l) Annual Sales kWh	(m) Rate Mills/kWh	(n) Estimated Annual Pymt
											[PROTECTED DATA BEGINS		
2025	1.000	1.000	1.000	1.000									
2026	1.000	1.008	1.029	1.038	1	$1,760	$1,286	1.0651	$1,207	$1,730		97.86	
2027	1.000	1.016	1.059	1.076	2	$1,826	$1,335	1.1345	$1,177	$1,730		97.86	
2028	1.000	1.024	1.091	1.117	3	$1,894	$1,385	1.2083	$1,146	$1,730		97.86	
2029	1.000	1.032	1.122	1.159	4	$1,965	$1,437	1.2870	$1,117	$1,730		97.86	
2030	1.000	1.041	1.155	1.202	5	$2,039	$1,491	1.3708	$1,088	$1,730		97.86	
2031	1.000	1.049	1.189	1.247	6	$2,116	$1,547	1.4601	$1,060	$1,730		97.86	
2032	1.000	1.057	1.224	1.294	7	$2,195	$1,605	1.5551	$1,032	$1,730		97.86	
2033	1.000	1.066	1.260	1.343	8	$2,277	$1,665	1.6564	$1,005	$1,730		97.86	
2034	1.000	1.074	1.297	1.393	9	$2,363	$1,727	1.7642	$979	$1,730		97.86	
2035	1.000	1.083	1.335	1.446	10	$2,452	$1,792	1.8791	$954	$1,730		97.86	
2036	1.000	1.092	1.374	1.500	11	$2,544	$1,859	2.0014	$929	$1,730		97.86	
2037	1.000	1.100	1.414	1.556	12	$2,639	$1,929	2.1318	$905	$1,730		97.86	
2038	1.000	1.109	1.456	1.614	13	$2,738	$2,002	2.2706	$882	$1,730		97.86	
2039	1.000	1.118	1.498	1.675	14	$2,841	$2,077	2.4184	$859	$1,730		97.86	
2040	1.000	1.127	1.542	1.738	15	$2,948	$2,155	2.5759	$837	$1,730		97.86	
2041	1.000	1.136	1.587	1.803	16	$3,058	$2,236	2.7436	$815	$1,730		97.86	
2042	1.000	1.145	1.634	1.871	17	$3,173	$2,319	2.9222	$794	$1,730		97.86	
2043	1.000	1.154	1.682	1.941	18	$3,292	$2,407	3.1125	$773	$1,730		97.86	
2044	1.000	1.163	1.731	2.014	19	$3,416	$2,497	3.3151	$753	$1,730		97.86	
2045	1.000	1.173	1.782	2.090	20	$3,544	$2,591	3.5310	$734	$1,730		97.86	
2046	1.000	1.182	1.834	2.168									
2047	1.000	1.192	1.888	2.249									
2048	1.000	1.201	1.943	2.334									
2049	1.000	1.211	2.000	2.421									
						$51,080	$37,342		$19,044	$34,597			

PROTECTED DATA ENDS]

Total Lump Sum Payment **$19,044**

Value of Levelized Payments **$19,044**

Value of Volumetric Payments **$19,044**

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	37.3%
Fixed Production	893,802	326,389	25,316	540,925	1,172	0.0%
Transmission	398,439	157,052	11,011	230,376	0	100.0%
Total Distribution	322,948	156,591	8,706	156,274	1,376	0.1%
Costs Avoided	1,140,529	448,820	36,210	646,366	9,134	
Costs NOT Avoided	2,572,486	1,063,986	82,942	1,400,736	24,821	
Total Revenue Requirement	3,713,015	1,512,806	119,152	2,047,102	33,955	
% of Costs Avoided	**30.72%**	**29.67%**	**30.39%**	**31.57%**	**26.90%**	

Year	Electric Rebate $
2016	$17,008.46
2017	$23,199.20
2018	$9,316.78
2019	$10,406.71
2020	$924.40
2021	$6,086.23
2022	$41,951.95
2023	$11,748.36
2024	$18,084.58
2025	$48,171.84
Total	$186,898.51
Average per Year	**$18,689.85**