Direct Testimony and Schedules
Laurie J. Wold

Before the South Dakota Public Utilities Commission
State of South Dakota

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

Docket No. EL25-___
Exhibit___(LJW-1)

Overall Revenue Requirements
Rate Base
Income Statement

June 30, 2025

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Laurie J. Wold. I am the Manager 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 SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have over 13 years of experience at XES, supporting Northern States Power Company–Minnesota (NSPM or the Company) in the areas of business area finance, plant accounting, operations finance, and revenue requirements. In my current role, I am responsible for the development of jurisdictional revenue requirements for all NSPM jurisdictions. My qualifications are provided as Exhibit___(LJW-1), Schedule 1.

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

A. I provide testimony supporting the Company's financial data and its request for a general rate increase in the State of South Dakota retail electric jurisdiction. My testimony supports the income statement and rate base portions of the South Dakota cost of service. My testimony also addresses the South Dakota electric jurisdiction's operational need for new incremental revenues of $43.6 million or 15 percent, based on a pro forma year with known and measurable changes.

In addition, the Company proposes moving some cost recovery from two of its rate riders to base rates or interim rates on January 1, 2026. During the pro forma year, the Company recovered $18.6 million through the Infrastructure Rider consistent with the projects approved in Docket No. EL24-029. Consistent with the terms of the Settlement establishing the Infrastructure Rider, we propose to move this cost recovery to base rates. Second, during the pro forma year the Company recovered $1.2 million in revenues through the Transmission Cost Recovery (TCR) Rider consistent with the projects approved in Docket No. EL24-030. Pursuant to Commission policy, those projects will be rolled into base rates. Together, moving cost recovery from the Infrastructure Rider and the TCR Rider eliminates $19.8 million in Infrastructure Rider and TCR Rider revenues. Consequently, the revenue requirement base rate increases by the same $19.8 million in order to replace the lost rider revenues, which has no overall rate impact to customers.

To summarize, we propose an overall increase in base rates of $63.4 million, of which $43.6 million is the net incremental amount of the base rate increase to our customers ($63.4 million total – $19.8 million rider transfer = $43.6 million incremental increase).

Q. WERE THE SCHEDULES PRESENTED WITH YOUR TESTIMONY PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were. Exhibit___(LJW-1), Schedule 2 provides an index of schedules presented with my testimony, including a description of the data and other filing sources.

Q. IN ADDITION TO THE SCHEDULES INCLUDED WITH THIS TESTIMONY, ARE THERE ADDITIONAL SCHEDULES YOU ARE SPONSORING?

A. Yes. I am sponsoring the following Statements and supporting Schedules, which are required by South Dakota Public Utilities Commission (Commission) Rules

(Sections 20:10:13:51 *et seq*.). These Statements and Schedules are located in Volume 1 of the Application:

A. Balance sheet

B. Income statement

C. Earned surplus statements

D. Cost of plant

   - D-1. Detailed plant accounts
   - D-2. Plant addition and retirement for test period
   - D-3. Working papers showing plant accounts on an average basis for test period
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   - D-7. Working papers on plant in service not used and useful
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To the extent the Commission's rules require a discussion of the content of these required Schedules, a discussion is provided with the required Schedule. Company witness Allen D. Krug sponsors Statement Q, providing the required description of utility operations. Company witness Christopher J. Barthol provides support for Statement O in his Direct Testimony.

Q. HAVE YOU RELIED ON INFORMATION PROVIDED BY OTHER WITNESSES IN PREPARING YOUR TESTIMONY AND SCHEDULES?

A. Yes. I relied on and incorporated information provided by other witnesses in this proceeding, as well as information provided by various Company business areas and subject matter experts. Where applicable, I indicate in my testimony where the pro forma year cost information is based on information provided by other witnesses.

II. CASE OVERVIEW

A. Test-Year Revenue Requirements and Deficiency

Q. DID YOU PREPARE A COST OF SERVICE STUDY THAT SUPPORTS THE REVENUE REQUIREMENT AMOUNT AND REVENUE DEFICIENCY FOR THE PRO FORMA YEAR?

A. Yes, a Cost of Service Study was prepared under my direction. Exhibit___(LJW-1), Schedule 3 contains a copy of the jurisdictional cost of service study for the pro forma year.

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

A. The general form for calculating the revenue requirement and revenue deficiency is as follows:

	Item	2024 Pro Forma Amount ($000s)	Exhibit__ (LJW-1), Sch. 2 Reference
	Rate Base	$947,135	Page 1, Line 44
multiplied by	Cost of capital	7.65%	Page 1, Line 20
	Operating Income Requirement	**$72,456**	Page 4, Line 158
	Current Retail Revenue	$247,154	Page 2, Line 47 + Line 48
plus	Current Other Revenue	$63,895	Page 2, Line 49
equals	Current Total Revenue	$311,049	Page 2, Line 50
minus	Operating Expenses	$186,583	Page 2, Line 74
minus	Depreciation Expense	$75,079	Page 2, Line 76
minus	Amortization Expense	$3,490	Page 2, Line 77
minus	Taxes	$8,298	Page 3, Line 135
plus	AFUDC		Page 4, Line 140 + Line 141
equals	**Total Available for Return**	**$37,598**	Page 4, Line 143
	Operating Income Requirement	$72,456	Page 4, Line 158
minus	Total Available for Return	$37,598	Page 4, Line 143
equals	**Income Deficiency**	**$34,858**	Page 4, Line 160
multiplied by	Gross Revenue Conversion Factor	1.265823	Page 4, Line 162
equals	**Revenue Deficiency**	**$44,123**	Page 4, Line 163
plus	Current Retail Revenue	$247,154	Page 4, Line 166
equals	**Total Revenue Requirement**	**$291,277**	Page 4, Line 168

Q. WHAT IS THE AMOUNT OF THE JURISDICTIONAL REVENUE REQUIREMENT FOR SOUTH DAKOTA?

A. The jurisdictional total retail revenue requirement for South Dakota electric utility operations is $333.2 million, based on the adjusted rate base (this adjustment is discussed in further detail in Section IV) and net operating income for the pro forma year, as adjusted for known and measurable changes occurring in 2025 and 2026, as appropriate for final rates that will go into effect January 1, 2026. The jurisdictional retail revenue requirement is also based on the average 2024 capital structure, a weighted cost of long-term debt of 2.11 percent and a weighted cost of equity of 5.45 percent, based on a return on equity of 10.30 percent (ROE) as recommended by Company witness Joshua C. Nowak in his Direct Testimony. This results in an overall rate of return (ROR) of 7.56 percent.

Q. WHAT IS THE AMOUNT OF THE REVENUE DEFICIENCY FOR THE PRO FORMA YEAR?

A. The incremental amount of the revenue deficiency (the amount by which the rates paid by our customers increases) for the pro forma year is $43.6 million or 15 percent. In addition, the Company currently recovers the costs of certain capital projects through the Infrastructure Rider and the TCR Rider, which will be recovered through an increase in base rates. The result is that the revenues collected under those two riders will decrease and will be replaced by an increase in base rates of $19.8 million, for a total increase in base rates of $63.4 million. As I will explain, the revenue deficiency includes $12.4 million in known and measurable capital project changes occurring in 2026 that, if the Commission prefers, could be recovered through the Infrastructure or TCR Riders. Regardless of how these costs are treated in the rate case, the Company requests that the Infrastructure and TCR Riders continue into the future.

A summary of the revenue deficiency is shown in Exhibit___(LJW-1), Schedule 4, as a comparison of the jurisdictional revenue requirement amount for the pro forma year with the revenues under present rates as approved by the Commission in Docket No. EL22-017.[1] In order to earn an overall ROR of 7.56 percent, South

[1] Present revenues as presented in the pro forma year are weather-normal base rate and fuel revenues plus the Transmission Cost Recovery (TCR), Demand Side Management (DSM), and Infrastructure Rider revenues.

Dakota retail electric rates need to be increased by this deficiency amount, as developed in Schedule 4.

Q. WHAT IS THE PERCENTAGE INCREASE IN RETAIL REVENUES PROPOSED IN THIS CASE?

A. The revenue deficiency amount represents a 15 percent increase in retail revenues compared to 2024 retail revenues at present rates as shown in Schedule 4. When the revenue requirement is increased to incorporate the revenues from the TCR and Infrastructure Riders, the increase in base rates represents a 21.9 percent overall increase compared to 2024 retail revenues.

B. Case Drivers

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section, I discuss the drivers of this rate case when compared to existing rates. I first discuss capital-related cost drivers, then amortizations driving the pro forma year revenue requirement, then tax-related cost drivers, then operation and maintenance (O&M) related cost drivers, and conclude with other margin related drivers.

Q. WHAT IS YOUR COMPARISON YEAR IN DESCRIBING COST CHANGES?

A. Consistent with the analysis provided in prior rate cases, my explanation of the key deficiency cost drivers uses a comparison to the Commission-ordered results from our last electric rate case (Docket No. EL22-017), which used a 2021 pro forma year. I will refer to the comparison year as the 2021 pro forma year.

Q. WHAT ARE THE MAJOR DRIVERS OF THE COMPANY'S NEED FOR RATE RELIEF?

A. A summary of the cost elements to which the revenue deficiency can be attributed is provided in Exhibit___(LJW-1), Schedule 5. The major cost elements driving the revenue deficiency are identified in Table 1 below.

Table 1
Net Deficiency ($ in millions)

	Increase (Decrease) 2024 PF to 2021PF
Capital and Capital Related	$63.7
Amortizations	0.6
Taxes	3.9
Operating Expense	11.4
Other Margin Impacts	(36.0)
Total Net Incremental Deficiency	$43.6

1. Capital Related Cost Drivers

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

A. Table 2 below compares the 2021 pro forma year forecast revenue requirements with the revenue requirements for the 2024 pro forma year, by category, for capital plant related costs as shown on Schedule 5.

Table 2
Capital and Capital Related Revenue Requirements Changes
($ in millions)

	Increase (Decrease) 2024 PF to 2021 PF
Distribution	$22.7
Cost of Capital	8.8
Steam	9.5
General and Intangible	7.9
All Other Production	6.2
Transmission	5.2
Wind	4.9
DTA (federal credits & NOL)	2.5
Nuclear	(4.6)
Other Rate Base	0.6
TOTAL Capital and Capital Related	$63.7

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

A. The 2024 pro forma year revenue requirements include a $22.7 million increase due to the Distribution business unit's capital investments in South Dakota compared to the 2021 pro forma year. This increase is due to capital investments made to add capacity to serve increased load, particularly in the Sioux Falls area, additions to serve new business, including in Sioux Falls, asset health and reliability spending, including in response to storm damage in 2022, and to improve system reliability and resilience, such as pole and underground cable replacements. Distribution also manages work associated with our meter replacement initiative, and the bulk of the new meters were installed in 2024. Additional information regarding Distribution's capital investments is provided in the Direct Testimony of Company witness Brandon T. Cramer.

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

A. The 2024 pro forma year revenue requirements includes an $8.8 million increase related to the Company's requested 10.3 percent ROE. Company witnesses Krug and Nowak discuss the Company's recommended ROE.

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

A. The capital increase for steam production of $9.5 million in the 2024 pro forma year revenue requirements from the 2021 pro forma year is the increased depreciation expense related to the accelerated plant retirements of King and Sherco Unit 3. Company witness Michelle A. Kietzman discusses the depreciation changes further in her Direct Testimony.

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

A. The 2024 pro forma year revenue requirements include a $7.9 million increase due to our investments in capital projects classified as General & Intangible compared to the 2021 pro forma year. This increase is mainly driven by investments in replacing aging technology, fleet assets, and service centers. Company witness Kietzman discusses these general asset investments further in her Direct Testimony.

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN OTHER PRODUCTION CAPITAL COSTS.

A. The 2024 pro forma year revenue requirements include a $6.2 million increase in capital related investments when compared to the 2021 pro forma year primarily due to solar investments at Sherco Unit 1, Unit 2, and Unit 3. Company witness Bixuan Sun discusses these energy resource investments further in her Direct Testimony.

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

A. The 2024 pro forma year revenue requirements include a $5.2 million increase due to Transmission capital investments when compared to the 2021 pro forma year. The increase compared to the 2021 pro forma year is due mainly to transmission plant investments in 2022-2024 and the roll-in of transmission capital projects which were in service by the end of 2024, particularly projects under the Asset Renewal program. Company witness Kietzman discusses transmission investments further in her Direct Testimony.

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

A. The 2024 pro forma year revenue requirements include a $4.9 million increase due to Wind capital related investments when compared to the 2021 pro forma year, particularly the additions of the Dakota Range, Northern, Nobles, and Grand Meadow wind farms. Company witness Kietzman discusses the Company's wind investments in her Direct Testimony.

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

A. The 2024 pro forma year revenue requirement includes a $4.6 million decrease when compared to the 2021 pro forma year related to the operating life extensions at the Company's Monticello and Prairie Island Nuclear facilities. The life extension caused reduced depreciation expense that more than offset the capital investments impact to the revenue requirement. Company witness Kietzman discusses the Company's nuclear lives in her Direct Testimony.

Q. ARE THERE OTHER CAPITAL RELATED DRIVERS?

A. Yes. The 2024 pro forma year revenue requirements include a $3.1 million increase over the 2021 pro forma year. This increase is driven by an increase in the deferred tax asset (DTA) of $2.5 million primarily due to federal tax credits.

2. Amortizations

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN AMORTIZATIONS.

A. The 2024 pro forma year revenue requirements include a $0.6 million increase related to amortizations compared to the 2021 pro forma year. This increase is primarily due to a newly proposed amortization for South Dakota's deferred jurisdictional portion of the Prairie Island Indian Community expenses, as authorized in Docket No. EL23-025. While we don't expect final approval of the plant operating license extension from the Nuclear Regulatory Commission (NRC) until 2028, we have filed the extension in Minnesota and anticipate approval in 2025. The life extension is assumed in the rate base filed in this case.

3. Taxes

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN TAXES.

A. The 2024 pro forma year revenue requirements include a $3.9 million increase due to taxes compared to the 2021 pro forma year. This increase is largely driven by increased property taxes.

4. O&M

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

A. Table 3 below compares the 2024 pro forma year forecast revenue requirements with the revenue requirements for the 2021 pro forma year, by category, for operating expenses as shown on Schedule 5.

Table 3
O&M Cost Changes ($ in millions)

	Increase (Decrease) 2024 PF to 2021 PF
A&G	$3.0
Transmission interchange	2.5
Nuclear	2.4
Wind	2.1
Purchased demand	1.1
Customer accounting / info / service	1.0
All other production	0.5
Distribution	0.4
Regional markets	0.1
Steam	(0.6)
Transmission	(0.8)
TOTAL O&M	$11.4

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

A. The 2024 pro forma year revenue requirements include a $3 million increase in A&G expense compared to the 2021 pro forma year. The increase, when compared to 2021, is primarily driven by the O&M associated with our investments in new information technology by our Technology Services business area. Specifically, software license and maintenance costs are driven by new projects and increased licensing costs which are driven by users and upgrades. There is also an increase in employee benefits due to higher active healthcare costs.

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

A. The 2024 pro forma year revenue requirements include a $2.5 million increase in transmission interchange operating expenses compared to the 2021 pro forma year. This increase is primarily due to the addition of the Bayfield Loop project in Wisconsin. I note that, because this capital project is located in Wisconsin and owned by the Company's sister company, Northern States Power Company – Wisconsin (NSPW), it is not included in rate base but is, instead, recovered through the Interchange Agreement,[2] and therefore recorded as an O&M expense.

Q. WHAT ARE THE REASONS FOR THE CHANGE IN NUCLEAR AND WIND OPERATING EXPENSE?

A. The 2024 pro forma year revenue requirements include a net increase of $4.4 million in nuclear and wind operating expenses compared to the 2021 pro forma year. Increased expenses for the generating facilities are primarily due to longer and more costly planned refueling outages at Prairie Island, higher regulatory fees driven by inflation and government spending, and higher security contractor costs driven by merit increases at the nuclear facilities and increased operations of the wind facilities.

5. Other Margin

Q. PLEASE DESCRIBE THE REVENUE REQUIREMENT IMPACT FOR THE PRINCIPAL CHANGES IN OTHER MARGIN.

A. Table 4 below compares the 2024 pro forma year forecast revenue requirements with the revenue requirements for the 2021 pro forma year, by category, for other margin as shown on Schedule 5.

[2] On March 14, 2025, Northern States Power Company, a Minnesota corporation (NSPM) and Northern States Power Company, a Wisconsin corporation (NSPW) submitted revisions to an Agreement to Coordinate Planning and Operations and Interchange Power and Energy (Interchange Agreement) between NSPM and NSPW under Docket No. ER25-1620-000. FERC accepted the filing on May 6, 2025, with an effective date of January 1, 2025.

Table 4
Net Deficiency ($ in millions)

	Increase (Decrease) 2024 PF to 2021 PF
Retail revenue – excluding fuel	($14.7)
Rider revenue	(19.8)
Other revenue	(1.6)
TOTAL Other Margin Impacts	($36.0)

Q. PLEASE DESCRIBE HOW CHANGES IN SALES IMPACT THE COMPANY'S REVENUE REQUIREMENTS.

A. From 2021 to 2024, South Dakota weather-normalized retail sales have increased by an average of approximately 2.0 percent per year, which increases revenue earned by the Company under current rates. The increased revenue offsets part of the revenue requirement.

Q. ARE THERE ANY OTHER MARGIN ITEMS WITH A SIGNIFICANT IMPACT ON THE 2024 PRO FORMA REVENUE DEFICIENCY?

A. Yes. As noted above, for the rider eligible cost increases in capital and capital-related wind and transmission there is a corresponding increase in rider revenue included in the cost of service study (COSS). The increase is $19.8 million compared to the 2021 pro forma year.

Q. ARE THE FUNCTIONAL CLASS CATEGORIES OF OPERATING EXPENSE COMPARABLE BETWEEN THE 2024 PRO FORMA YEAR FORECAST AND THOSE CONTAINED IN 2021 RATE CASE PRO FORMA YEAR?

A. Yes. Both categorizations conform to the FERC Uniform System of Accounts.

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 pro forma year and the jurisdictional cost of service study (JCOSS).

A. Data Provided and Selection of Pro Forma Year

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

A. Following the rules of the Commission, financial data is provided for the calendar year 2024 (unadjusted test year) and the pro forma year that includes 2025 and 2026 known and measurable adjustments.

Financial data is first normalized to remove any unusual conditions in the actual year (*e.g.,* weather normalization) that should be adjusted for rate setting purposes. Next, the actual year is adjusted for regulatory treatment (*e.g.,* foundation administration expenses and certain advertising expenses are removed). Financial adjustments are made to align with updated operations or asset related information and included in direct testimony, schedules, and workpapers (*e.g.,* depreciation and dismantling studies). Additional adjustments are made to reflect standard amortizations. Finally, I make pro forma adjustments to reflect known and measurable changes occurring in 2025 and 2026 pursuant to Commission Rule 20:10:13:44, which permits a period of up to 24 months from the end of the historical test period to be considered in developing known and measurable adjustments. This ensures that final rates, which should become effective in 2026, more closely reflect the Company's revenues and expenses at the time the rates go into effect. The pro forma year COSS is summarized in Schedule 3.

I provide in Schedule 3 a COSS for the unadjusted 2024 year showing: the actual unadjusted average rate base; unadjusted operating income; overall rate of return; the calculation of required income; the income deficiency; and revenue requirements. Exhibit___(LJW-1), Schedules 6A and 6B are separate rate base and income statement bridge schedules that identify the adjustments described in my testimony to the unadjusted 2024 test year that create the pro forma year.

B. Jurisdictional Cost of Service Study (JCOSS)

Q. PLEASE DESCRIBE THE COMPONENTS OF THE JCOSS FOR THE PRO FORMA YEAR.

A. The complete JCOSS is included in Volume 3 (Workpapers) of the Company's filing. The JCOSS includes: a revenue requirement, rate base, income statement, income tax, and a cash working capital computation.

Q. PLEASE DESCRIBE THE JCOSS SUMMARY SCHEDULES.

A. The pro forma year JCOSS summary is included in Schedule 3. To facilitate a comparison to the unadjusted 2024 test year, we have also included the 2024 unadjusted test year JCOSS summary in Schedule 3.

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

A. Yes. The revenue conversion factor of 1.2658, using a South Dakota composite tax rate of 21 percent, is included in my exhibit Schedule 3, page 4, line 163.

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.

Q. DOES THE 2024 UNADJUSTED TEST YEAR PROVIDED IN YOUR SCHEDULES 6A AND 6B MATCH THE 2024 JURISDICTIONAL REPORT?

A. No, they are different. The rate case includes cash working capital in the rate base, while the jurisdictional report does not. Also, the 2024 Jurisdictional Report does not include the proposed adjustments presented to the pro forma year.

IV. RATE BASE

Q. IS THE PRO FORMA YEAR RATE BASE REASONABLE FOR PURPOSES OF DETERMINING FINAL RATES IN THIS PROCEEDING?

A. Yes. The pro forma year rate base was developed based on sound ratemaking principles, in a manner substantially similar to prior Company electric rate cases. This includes a historical test year and two years of known and measurable capital investments.

Q. PLEASE EXPLAIN WHAT RATE BASE REPRESENTS.

A. Rate base primarily reflects the costs of capital additions made by a utility to secure plant, equipment, materials, supplies and other assets 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 PRO FORMA YEAR RATE BASE.

A. The pro forma year rate base is generally comprised of the following major items, which will be described in further detail later in my testimony:

- Net Utility Plant,
- Accumulated Deferred Income Taxes, and
- Other Rate Base.

Q. HOW DOES THE COMPANY CALCULATE RATE BASE?

A. The Company's rate base can be expressed using the breakdown on page 27 of the "Electric Utility Cost Allocation Manual" of the National Association of Regulatory Utility Commissioners (NARUC) as follows:

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

In this case, the calculation is as follows:

Plant	$2,285.0 million	(per LJW-1, Sch 3, Page 1, Line 23)
Reserve	($920.9 million)	(per LJW-1, Sch 3, Page 1, Line 24)
ADIT	($165.8 million)	(per LJW-1, Sch 3, Page 1, Line 33)
Working Capital	($3.4 million)	(per LJW-1, Sch 3, Page 1, Line 35)
Other Rate Base	$44.4 million	(per LJW-1, Sch 3, Page 1, Lines 36-42)
Total Rate Base	$1,239.3 million	(per LJW-1, Sch 3, Page 1, Line 45)

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

A. Schedule 6A is a bridge schedule that shows the 2024 unadjusted test rate base, each proposed rate base adjustment, and the resulting proposed pro forma rate base.

Exhibit___(LJW-1), Schedule 7 provides a comparison of rate base components based on the final decision in the Company's last rate case filing (Docket No. EL22-017) to the pro forma year assuming final rates.

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 13-month average of net plant balances. This presentation is consistent with the net utility plant calculation in settlement in Docket No. EL22-017.

Q. WHAT HISTORICAL BASE DID XCEL ENERGY RELY ON AS A STARTING POINT TO DEVELOP THE NET PLANT BALANCE FOR THE PRO FORMA YEAR?

A. The historical base used was Xcel Energy's actual net investment (Plant in Service less Accumulated Depreciation) on the books and records of the Company as of December 31, 2024 plus the applicable adjustments, discussed in detail in Section VII below, to create the pro forma net plant balance.

B. Construction Work In Progress (CWIP)

Q. HAS CWIP BEEN INCLUDED IN THE PRO FORMA YEAR RATE BASE?

A. No. CWIP is not included in rate base, and there is no corresponding offset of Allowance for Funds Used During Construction (AFUDC) added to operating income.

C. Accumulated Deferred Income Taxes (ADIT)

Q. PLEASE DESCRIBE ADIT.

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 is typically the extent to which accelerated 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 deferred income taxes have been allowed for recovery in rates, they represent a non-investor source of funds. Accordingly, the 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.

D. Other Rate Base

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

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

Q. PLEASE EXPLAIN WHAT WORKING CAPITAL REPRESENTS.

A. Working Capital is the 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 requirements, also referred to as Cash Working Capital, are shown separately.

Q. HOW WERE PRO FORMA YEAR MATERIALS AND SUPPLIES AND FUEL INVENTORY REQUIREMENTS CALCULATED?

A. The Materials and Supplies and Fuel Inventory amounts shown on Schedule 3, page 1, are based on the 13-month average ending balances for December 2023 through December 2024, respectively. The Materials and Supplies average balance included in the pro forma year rate base equals $15.5 million. The pro forma year average rate base amount for Fuel Inventory is $6.4 million.

Q. HOW WERE PRO FORMA YEAR NON-PLANT ASSETS AND LIABILITIES AND REGULATORY AMORTIZATIONS DETERMINED?

A. These balances, as shown on Schedule 3, page 1, represent the December 2023 through December 2024 actual 13-month average balances. Any book/tax timing differences associated with these items have been reflected in the determination of current and deferred income tax provision and accumulated deferred tax balances previously discussed. The net assets increase pro forma year rate base by $18.8 million.

Q. HOW WERE PRO FORMA YEAR PREPAYMENTS AND OTHER WORKING CAPITAL ITEMS DETERMINED?

A. Items of Prepayments and Other Working Capital, such as customer advances and deposits, are based on the 13-month average ending balances for December 2023 through December 2024. The net impact of these various items increases pro forma year rate base by $3.7 million as shown on Schedule 3, page 1.

Q. HOW WERE PRO FORMA YEAR 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 pro forma year revenues and expenses.

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 dates the costs of rendering the services are incurred until the related disbursements are made.

Q. HAS XCEL ENERGY'S LEAD/LAG STUDY BEEN UPDATED SINCE THE LAST SOUTH DAKOTA ELECTRIC RATE CASE (DOCKET NO. EL21-017)?

A. Yes. The average lag days are measured on the 12 months ended December 31, 2023. The results of the updated lead/lag study for electric operations were incorporated into the South Dakota jurisdiction cash working capital calculations provided in Volume 1, Required Statements, Statement N. The lead/lag study can be found in Volume 4 of our Application. Overall, the methodology used for calculating the lead/lag days is consistent with the Company's last electric rate case; however, the Company is proposing several changes in this rate case.

Q. WHAT CHANGES IS THE COMPANY PROPOSING FOR THE LEAD/LAG STUDY IN THIS RATE CASE?

A. In the Commission-approved Settlement Stipulation in Docket EL22-017, the cash working capital calculation included vacation pay, interest on long term debt and a 20-day cap on revenue lag days. The Company does not believe these amounts are correctly included in the cash working capital calculation.

Vacation pay is a component of regular payroll and is paid out in the same manner; therefore, it is not appropriate to segregate it and assign payment lead days that are not consistent with regular payroll.

Interest on long term debt in the pro forma cost of service is an embedded calculation based on the 2024 debt rates and ratios and the pro forma rate base. The debt cost is based on the blended rates of the total debt portfolio. The result is a representative amount of interest expense (interest paid and accrued) for the pro forma year and, therefore, does not have any associated lead days to include in the cash working capital calculation.

Q. IS THE COMPANY PROPOSING A CHANGE TO THE LEAD/LAG STUDY RELATED TO THE 20-DAY CAP ON REVENUE LAG DAYS?

A. Yes. The Company is proposing to increase the cap to 30 days for revenue lag days. While it is appropriate to cap the revenue lag days when removing late payment revenue based on the precedential adjustment provided in Volume 3, Section VIII Adjustments, Tab A12, the Company invoices customers on a monthly billing cycle, and any overdue customers are charged late payments if payment is not received within approximately 30 days; therefore, it is more appropriate to use a revenue cap of 30 days for the cash working capital calculation.

Q. WHAT IS THE PRO FORMA YEAR CASH WORKING CAPITAL AMOUNT?

A. The amount included in rate base is a reduction of $3.4 million. The detailed components and calculations associated with this amount are provided in Volume 1, Required Statements, Statement N.

Q. IS THE PRO FORMA YEAR RATE BASE FOR THE COMPANY'S SOUTH DAKOTA JURISDICTION ELECTRIC OPERATIONS REASONABLE FOR PURPOSES OF DETERMINING FINAL RATES IN THIS PROCEEDING?

A. Yes. The pro forma year rate base was developed on sound ratemaking principles in a manner similar to prior Company South Dakota electric rate cases.

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 pro forma year income statement.

Q. IS THE COMPANY'S PROPOSED PRO FORMA INCOME STATEMENT REASONABLE FOR DETERMINING FINAL RATES IN THIS PROCEEDING?

A. Yes. The pro forma income statement for the Company's South Dakota jurisdiction electric operations was developed based on sound ratemaking principles in a manner similar to prior Company electric rate cases.

Q. PLEASE IDENTIFY THE MAJOR COMPONENTS OF THE INCOME STATEMENT.

A. The following are the major components of the income statement:

- Revenues,
- Operating and Maintenance Expenses,
- Depreciation Expense,
- Taxes, and
- Net Income.

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

A. Exhibit___(LJW-1), Schedule 8 provides a comparison of income statement components from the final decision in the Company's last rate case filing (Docket No. EL22-017) to the income statement components in the pro forma year assuming final rates.

Schedule 6B is a bridge schedule that shows the 2024 unadjusted test year income statement, each proposed income statement adjustment, and the resulting proposed 2024 pro forma year income statement.

A. Revenues

Q. PLEASE DESCRIBE ANY CHANGES MADE TO THE PRESENT REVENUES IN THE PRO FORMA YEAR ENDED DECEMBER 31, 2024.

A. The present revenues used in the pro forma year were adjusted to ameliorate the effect of weather, as discussed further by Company witness Nicholas N. Paluck. The present revenue based on actual 2024 data are affected by weather that is not necessarily representative of a typical or average weather pattern. Therefore, we used the same weather normalization technique as we did in past cases for the present revenue in the pro forma year.

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

A. Yes. The pro forma year includes items such as revenues from transmission-related assets and specific tariff charges including service activation fees, reconnection fees and others. One other source of revenues comes from billings to NSPW under the Interchange Agreement, which I discuss in more detail below. Inclusion of these other operating revenues lower the income deficiency and ultimately the revenue deficiency.

B. Operating and Maintenance Expenses (O&M)

Q. HOW DOES THE COMPANY CALCULATE OPERATING EXPENSES?

A. The Company's operating expenses can be expressed using the breakdown on pages 30-31 of the "Electric Utility Cost Allocation Manual" of NARUC as follows:

Operation and Maintenance Expense (including fuel) (Operating Expense)
Plus: Depreciation Expense (Depreciation)
Plus: Miscellaneous Amortization Expense (Amortization)
Plus: Taxes other than Income Taxes (Other Taxes)
Plus: Income Taxes (Income Tax)
Equals: Total Operating Expenses

In this case, the calculation is as follows (amounts are in millions):

Operating Expense	$186.0	(per LJW-1, Sch 3, Pg 2, Line 75)
Plus Depreciation	$77.3	(per LJW-1, Sch 3, Pg 2, Line 77)
Plus Amortization	$ 3.1	(per LJW-1, Sch 3, Pg 2, Line 78)
Plus Other Taxes	($4.1)	(per LJW-1, Sch 3, Pg 2, Line 89)
Plus Income Tax	$23.5	(per LJW-1, Sch 3, Pg 3, Line 135)
Total Operating Expense	$285.8	(per LJW-1, Sch 3, Pg 3, Line 139)

C. Depreciation Expense

Q. WHAT IS THE BASIS OF THE DEPRECIATION RATES AND EXPENSE USED IN THE PRO FORMA YEAR?

A. Depreciation expense for the pro forma year base data reflects the Company's depreciation rates approved in our last rate case (Docket EL22-017) and adjustments for Remaining Lives of Power Generation facilities and Depreciation Rates for Transmission, Distribution and General Accounts. These adjustments are discussed in Section VII (adjustments 4 and 9). Company witness Kietzman discusses the Company's depreciation expense in her Direct Testimony.

D. Taxes

Q. WHAT TAX EXPENSES ARE INCLUDED IN THE PRO FORMA YEAR INCOME STATEMENT?

A. We have line items for Property; Income Taxes, including Deferred Income Tax, Investment Tax Credits, Federal Income Tax; and Payroll Taxes. The Federal income taxes are calculated in Schedule 3, 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, and 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 3, Section III Rate Base (Plant), Tab P6, Property Taxes 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 income taxes. The federal income tax rate reflects the 21 percent rate effective January 1, 2018 with the enactment of the Tax

Cut and Jobs Act (TCJA). The utilization or generation of net operating losses or tax credits impact both deferred income taxes and federal income taxes, which I will discuss in more detail below.

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

A. A NOL is created when taxable deductions exceed taxable revenue; when this occurs, the excess deductions are carried forward to future periods. NOLs require an adjustment that offsets the part of the ADIT rate base reduction that is associated with the accelerated depreciation deductions. 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 is required under federal income tax law as part of "normalization" for both accounting and ratemaking.

Q. PLEASE EXPLAIN HOW THE COMPANY DETERMINES WHETHER DTAS ARE CREATED OR CONSUMED.

A. The calculation of income taxes determines whether DTAs are created or consumed. Simply put, if tax deductions exceed taxable income any excess deductions are deferred as well as all tax credits earned during the year. These deferred deductions and tax credits create a DTA that is "carried forward" to future years. If taxable income exceeds all current year tax deductions, any deductions carried forward from prior years may be utilized to reduce taxable income. Any remaining taxable income can be reduced further by any available tax credits. Prior year deductions or credits utilized or consumed reduce the DTA.

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 and unused deductions can reduce taxable income up to 80 percent and unused credits can reduce any remaining tax expense by 75 percent.

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 Company's Electric Utility South Dakota retail jurisdiction is in a tax loss position or in a position to utilize deductions and credits carried forward from previous periods, as is the case with the 2025 test year. 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 reduction to base rates.

These balances related to unused credits and deductions are reported in the Company's Jurisdictional Annual Reports, including the most recent June 1, 2024, Jurisdictional Annual Report. By having these annual determinations made on an all-in basis, the 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 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 Production Tax Credits (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.

Q. WHAT ARE PTCS?

A. PTCs are per-kWh tax credits to income for electricity generated using qualified energy resources.

Q. WHAT AMOUNT OF PTCS SALES IS THE COMPANY REFLECTING IN THE 2024 PRO FORMA YEAR?

A. The 2024 pro forma year reflects the actual PTC sales in 2024.

Q. DO THE DTAS AFFECT THE PRO FORMA YEAR REVENUE REQUIREMENTS?

A. Yes. The Company's pro forma year COSS includes a revenue requirement increase associated with NOLs and PTCs carried forward from prior periods to the pro forma year and generation or utilization of federal tax credits to be carried forward based on the Company's pro forma year COSS. Accounting for the balances carried forward to the pro forma year COSS, as well as the documented calculations supporting this revenue requirement increase, can be found in Volume 3, Section VIII Adjustments, Tab A38.

It should be noted that any change 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. The Company will update the pro forma year COSS accordingly.

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE TREATMENT OF PTCS?

A. The Company continues to recommend that the Infrastructure Rider serve as the mechanism for returning PTCs to customers. This approach meets our understanding of the current regulatory treatment for PTCs.

E. AFUDC

Q. WHAT IS AFUDC?

A. AFUDC is the cost of financing during the period a capital investment is constructed. Once an asset is placed in service, the total cost to construct, including accumulated AFUDC, is recovered through depreciation expense. As previously noted, CWIP is not included in rate base, therefore there is no corresponding offset of AFUDC added to operating income.

F. Interchange Agreement

Q. PLEASE DESCRIBE THE INTERCHANGE AGREEMENT WITH NSPW.

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

Q. PLEASE DESCRIBE THE COSTS 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 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 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 certain non-retail revenues received by the Company and NSPW, such as revenues from off-system wholesale sales.

The 2024 unadjusted test year Interchange Revenue and Interchange Expenses have been calculated using 2024 Company and NSPW actual information. This is consistent with the treatment of Interchange Revenues and Interchange Expenses in the Company's 2021 unadjusted test year in Docket No. EL22-017.

Q. TO WHAT FERC ACCOUNTS ARE INTERCHANGE REVENUE AND INTERCHANGE EXPENSES RECORDED?

A. During 2024, Interchange Agreement revenues related to fixed and variable production, as well as transmission system costs, are recorded to FERC Account 456 – Other Electric Revenues. Interchange Agreement expense (billings from NSPW to the Company) are recorded to the following FERC Accounts:

Interchange Agreement Cost	FERC Account and Description
Fixed Production	557 – Other Power Supply Expenses-Other
Variable Production	557 – Other Power Supply Expenses-Other
Transmission	565 – Miscellaneous Transmission Expenses

Workpapers supporting the calculation for Interchange Agreement revenues (billings from the Company to NSPW) can be found in Volume 3, Section IV, Tab – R3, Interchange. Workpapers supporting the calculation of Interchange Agreement expenses (billings from NSPW to the Company) can be found in Volume 3, Section V, Tab – O5, Interchange. Copies of FERC filings and orders amending the Interchange Agreement since our last rate case are provided in Volume 4.

VI. UTILITY AND JURISDICTIONAL ALLOCATIONS

Q. PLEASE DESCRIBE THE METHODS USED TO ALLOCATE COSTS TO THE COMPANY'S ELECTRIC UTILITY OPERATIONS.

A. The pro forma year includes both costs incurred directly by the Company's electric operating business and costs directly assigned or allocated by the Service Company for corporate functions (*e.g.,* accounting, human resources, legal, etc.). The Service Company cost allocation and billing process is subject to FERC jurisdiction and authorization under a Utility Services Agreement between the Service Company and the Company.

Cost allocation and assignment principles have not changed since our last South Dakota electric rate case. O&M cost assignments and allocations are also consistent with the Company's recent Minnesota electric rate case filed on

November 1, 2024, with the Minnesota Public Utilities Commission (MPUC Docket No. E002/GR-24-320), and the North Dakota electric rate case filed on December 2, 2024, with the North Dakota Public Service Commission (NDPSC Case No. PU-24-376). Non-O&M costs include such items as book depreciation expense, deferred income taxes, and property taxes. All of the investments common to the electric and natural gas utilities, and their related costs (*e.g.*, software or other common investments and expenses), are evaluated as to whether the cost should be direct assigned to electric or natural gas, or allocated based on appropriate allocators such as: Customers, Customer Bills, Transportation Studies, or the three factor general allocator (the average of Revenue Ratio, Employee Ratio, and Asset Ratio).

Additional information regarding this process and the reason for selecting a particular allocator is also included in the Cost Assignment and Allocation Manual (CAAM), which is provided in Volume 4. There have not been any changes since the Company's last electric rate case that would significantly impact the percentage of costs that are assigned to South Dakota.

Q. PLEASE EXPLAIN THE NEED FOR JURISDICTIONALLY ALLOCATING THE INVESTMENTS IN PRODUCTION AND TRANSMISSION FACILITIES.

A. The NSPM and NSPW production and transmission system (NSP System) is designed, built, and operated to provide an integrated source of electricity for all of NSPM and NSPW's electric customers in five states. Costs are allocated first between NSPM and NSPW through the Interchange Agreement as approved by FERC, which I discussed earlier in my testimony. NSPM's portion of costs is then allocated to utility operations in South Dakota, North Dakota, and Minnesota.

To determine the level of investment associated with the provision of electric service to South Dakota retail customers, it is necessary to assign or allocate a portion of the total production and transmission investment to each jurisdiction. We used each jurisdiction's respective coincident peak demands for electricity as the basis for this allocation. It is reasonable to use coincident peak demands as an allocation basis because these facilities are constructed to meet both overall base load, intermediate, and peak requirements and operate as an integrated system across all jurisdictions. This is consistent with the methodology accepted in the Company's last South Dakota electric rate case. The exception to this is the Company-owned wind projects, which are allocated to jurisdiction based on energy consumed by South Dakota customers. We believe this is a more reasonable allocation basis since wind farms are generally constructed to meet energy needs, not to meet demand requirements.

Q. HOW WERE THE DISTRIBUTION INVESTMENT AMOUNTS ASSIGNED TO THE SOUTH DAKOTA JURISDICTION?

A. The Company's electric distribution plant investment amounts have been directly assigned, when possible, based upon the jurisdiction(s) served by each of the individual distribution facilities. Therefore, South Dakota distribution investments are generally assigned directly to South Dakota. However, if Distribution Investments include components that are common or general plant in nature, they are allocated based on their functional class, consistent with the CAAM.

Q. PLEASE DESCRIBE ANY CHANGES MADE TO THE ALLOCATION FACTORS FOR USE IN THE PRO FORMA YEAR ENDED DECEMBER 31, 2024.

A. The jurisdictional demand allocation factor used in the pro forma year was adjusted to remove the effect of weather. The allocation factor is based on actual

2024 data (coincident peak demand), that is affected by weather that is not necessarily representative of a typical or average weather pattern. Therefore, it is necessary to weather normalize the coincident peak demand data prior to calculating the allocation factors. We made a similar weather normalizing adjustment to present revenues as discussed in Section V.A. The allocation factors used in developing data in the unadjusted and pro forma year ending on December 31, 2024, may be found in the Volume 3, Section VII Workpapers.

VII. PRO FORMA ADJUSTMENTS

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

A. In this section of my testimony, I explain adjustments made to the 2024 actual year to make the resulting pro forma year appropriate for setting rates that will be finalized and applied to the service provided in 2026. 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 pro forma year.

Q. PLEASE DESCRIBE THE TYPES OF ADJUSTMENTS MADE TO THE PRO FORMA YEAR.

A. I present traditional adjustments consistent with treatment in prior cases and existing Commission Policy Statements (Precedential Adjustments) and rate case adjustments related to this particular case (Rate Case Adjustments). Next, I explain the various amortizations affecting the pro forma year (Amortizations), the removal of certain costs and revenues being recovered through riders (Rider Removals), various known and measurable adjustments (Known and Measurable

Adjustments), a group of adjustments that are the result of secondary dynamic calculations in the cost of service model (Secondary Calculations), and certain adjustments that may be necessary for Rebuttal Testimony in this proceeding.

Q. PLEASE LIST ALL THE PRO FORMA ADJUSTMENTS.

A. A list of the pro forma year adjustments is shown on Exhibit___(LJW-1), Schedule 9. I will also discuss each adjustment later in my testimony. In addition, I provide bridge schedules Schedule 6A and Schedule 6B that show all rate case adjustments, amortizations, rider removals, known and measurable adjustments, and secondary calculations. The following sections discuss each pro forma year adjustment in more detail.

A. Precedential Adjustments

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

A. Schedule 9 provides a list of Precedential Adjustments and their associated revenue requirement impact, based on past rate case precedent.

Q. HOW DOES THE COMPANY PROVIDE SUPPORT FOR THESE PRECEDENTIAL ADJUSTMENTS?

A. Treatment of these precedential adjustments has not changed from the Commission's Orders in the Company's previous completed electric rate cases. 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 Schedule 9. This organization is intended to facilitate the review of and full support for each adjustment within the identified workpaper.

B. Rate Case Adjustments

1. Bad Debt

Q. PLEASE DESCRIBE THE BAD DEBT ADJUSTMENT.

A. The unadjusted 2024 bad debt expense is based on the year-end financial statement accrual. To be consistent with the last settlement agreement, an adjustment was made to reflect the 2024 South Dakota net write-offs as the bad debt expense in the pro forma test year. An analysis was then performed to update the revised bad debt expense to account for the additional revenue deficiency in the 2024 pro forma year. This second adjustment is needed to incorporate the updated bad debt amount into the revenue requirement, which best reflects test year costs.

This combined adjustment impacts the pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 1, row 40, column 7,
- Schedule 9, page 1, row 20, column 5, and
- Volume 3, Section VIII Adjustments, Tab A16.

2. Credit Card AutoPay

Q. PLEASE DESCRIBE THE CREDIT CARD AUTOPAY ADJUSTMENT.

A. The credit card autopay adjustment is a proposal the Company is making in the pro forma year to improve this payment option for customers and include credit card processing costs in base rates rather than have customers continue to be charged on a per-transaction basis. To align with this program in other NSPM jurisdictions, we are proposing to establish a baseline amount of credit card fees for the South Dakota jurisdiction in base rates and track actual costs for the South Dakota jurisdiction above or below that baseline for recovery or return to customers in a future rate case. Company witness Krug also discusses the Company's proposal in his Direct Testimony.

Q. WHY DOES THE COMPANY BELIEVE A TRACKER WOULD BE APPROPRIATE?

A. Given that this is a new means of managing credit card costs for NSPM, prior to program implementation it is difficult to predict how it will affect customer behavior and the extent to which it will change Company credit card payment costs. A tracker would mitigate any risk of over- or under-collection so that only actual costs are ultimately recovered through rates.

Q. PLEASE DESCRIBE THE COMPANY'S TRACKER PROPOSAL IN MORE DETAIL.

A. The Company currently estimates annual total electric credit card fees of approximately $0.5 million, once customers are no longer charged individually for each transaction. We propose to establish this amount in our pro forma year revenue requirement and track actual annual fees above and/or below this baseline between initiating the program (approximately January 1, 2026) and our next South Dakota electric rate case. We would then address the net regulatory asset or liability in our next rate case.

Q. WHY IS THIS TRACKER PROPOSAL REASONABLE?

A. This will be a new program for NSPM[3], which we anticipate will modernize payment options for our customers and enhance our customers' experience with their electric utility service, making it consistent with the practices of other businesses. The tracker will ensure the Company does not over- or under-collect credit card fees in the pro forma year in relation to this program and will also

[3] Implementation of a similar program in Minnesota occurred in 2024.

enable reporting in our next rate case on the extent to which customers take advantage of this option.

Q. HOW IS THIS ADJUSTMENT IMPACTING THE PRO FORMA YEAR REVENUE REQUIREMENTS?

A. This adjustment impacts the pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 1, row 40, column 8;
- Schedule 9, page 1, row 21, column 5, and
- Volume 3, Section VIII Adjustments, Tab A17

3. Decommissioning

Q. PLEASE DESCRIBE THE DECOMMISSIONING ADJUSTMENT TO RATE BASE.

A. This adjustment updates the pro forma year to include the impact of decreasing the nuclear decommissioning accrual. This adjustment is further supported by Company witness Kietzman in her Direct Testimony.

This adjustment impacts the 2024 pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 1, row 40, column 9,
- Schedule 9, page 1, row 22, column 5, and
- Volume 3, Section VIII Adjustments, Tab A18.

4. Depreciation Study – Transmission, Distribution, and General (TD&G)

Q. PLEASE DESCRIBE THE DEPRECIATION STUDY ADJUSTMENT.

A. This adjustment updates the 2024 pro forma year to include the impact of the Company's 2022 Depreciation Study related to TD&G. This adjustment is further supported by Company witness Kietzman in her Direct Testimony.

This adjustment impacts the 2024 pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 1, row 40, column 10,
- Schedule 9, page 1, row 23, column 5, and
- Volume 3, Section VIII Adjustments, Tab A19.

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 membership dues paid to various Chambers of Commerce in South Dakota in the pro forma year. 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 appropriate. Chamber of Commerce dues are initially recorded below the line; thus, an adjustment is necessary to include Chamber of Commerce dues in pro forma year costs.

This adjustment impacts the pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 1, row 40, column 11,
- Exhibit___(LJW-1), Schedule 10, page 1, row 24, column 5, and
- Volume 3, Section VIII Adjustments, Tab A20.

6. *End of Life (EOL) Nuclear Fuel Update*

Q. PLEASE DESCRIBE THE EOL NUCLEAR FUEL UPDATE ADJUSTMENT.

A. The EOL Nuclear Fuel adjustment reflects a change in nuclear fuel expense for nuclear fuel commodities associated with the last few reloads at each unit. These revised cost estimates were the result of the Company's updated study that revised the cost of the unburned nuclear fuel at the time of shutdown of our nuclear generating plants. Support for this change is provided by Company witness Kietzman in her Direct Testimony.

This adjustment impacts the pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 1, row 40, column 12,
- Schedule 9, page 1, row 25, column 5; and
- Volume 3, Section VIII Adjustments, Tab A21.

7. *Foundation and Other Donations*

Q. PLEASE DESCRIBE THE CHARITABLE CONTRIBUTION ADJUSTMENT.

A. The Company is proposing to include 50 percent of corporate charitable contributions benefiting the State of South Dakota in the pro forma year. An analysis was performed on contribution details to ensure that only amounts contributed to charities and institutions that could be associated with the Company's electric service territory in the South Dakota jurisdiction were included in the cost of service.

This adjustment impacts the pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 1, row 40, column 13,

- Schedule 9, page 1, row 26, column 5, and
- Volume 3, Section VIII Adjustments, Tab A22.

8. Incentive Compensation

Q. WHAT ADJUSTMENTS HAVE YOU MADE TO THE INCENTIVE COMPENSATION EXPENSE INCLUDED IN THE PRO FORMA YEAR?

A. We have adjusted pro forma year costs to include the costs for the long-term incentive (LTI) compensation related to Company achievement of environmental goals and exclude the costs for all Annual Incentive Plan amounts above 20 percent of everyone's base pay. Company witness Krug supports this adjustment in his Direct Testimony.

This adjustment impacts the 2024 pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 1, row 40, column 14,
- Schedule 9, page 1, rows 27, column 5, and
- Volume 3, Section VIII Adjustments, Tabs A23.

9. Remaining Life

Q. PLEASE DESCRIBE THE DISMANTLING STUDY ADJUSTMENT.

A. This adjustment updates the 2024 pro forma year to include the impact of changes to remaining lives resulting from the Company's 2024 Dismantling Study. This adjustment is further supported by Company witness Kietzman in her Direct Testimony.

Q. PLEASE DESCRIBE THE REMAINING LIFE - ITC ADJUSTMENT.

A. This adjustment updates the 2024 pro forma year to include the remaining life impacts of the Company's proposed remaining lives adjustments as the ITCs unwind slower when plant lives are extended, and flow back quicker when lives are shortened. Company witness Kietzman further discusses the South Dakota proposed remaining life adjustments in her Direct Testimony.

Q. PLEASE DESCRIBE THE REMAINING LIFE - KING ADJUSTMENT.

A. This adjustment reflects the impact of shifting the King Plant's retirement date from 2037 to 2028 on the 2024 pro forma year based on the Company's 2024 Dismantling Study. This adjustment is further supported by Company witness Kietzman in her Direct Testimony.

Q. PLEASE DESCRIBE THE REMAINING LIFE - MONTICELLO ADJUSTMENT.

A. This adjustment reflects the impact of shifting the Monticello Plant's retirement date from 2040 to 2050 on the 2024 pro forma year based on the Company's 2024 Dismantling Study. This adjustment is further supported by Company witness Kietzman in her Direct Testimony.

Q. PLEASE DESCRIBE THE REMAINING LIFE - PRAIRIE ISLAND ADJUSTMENT.

A. This adjustment reflects the impact of shifting the Prairie Island Unit 1 and Unit 2 retirement dates to 2054 on the 2024 pro forma year based on the Company's 2024 Dismantling Study. This adjustment is further supported by Company witness Kietzman in her Direct Testimony.

Q. Please describe the remaining life - Sherco Unit 3 adjustment.

A. An adjustment to reflect the impact of shifting the Sherco Unit 3 retirement dates from 2034 to 2030 on the 2024 pro forma year based on the Company's 2024 Dismantling Study. This adjustment is further supported by Company witness Kietzman in her Direct Testimony.

These combined remaining life adjustments impact the 2024 pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 1, row 40, column 15,
- Schedule 9, page 1, row 28-33, column 5, and
- Volume 3, Section VIII Adjustments, Tab A24-29.

10. Storm Damage

Q. What adjustment did you make regarding storm damage expense?

A. I normalized annual storm damage O&M based upon the five-year average of the actual expense. This same process was also followed in last two rate cases. Consequently, I normalized the annual storm damage by replacing the actual storm damage costs in the 2024 unadjusted test year with the average storm damage costs for the five-year period from 2020 through 2024.

This adjustment impacts the 2024 pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 2, row 40, column 16,
- Schedule 9, page 1, row 34, column 5, and
- Volume 3, Section VIII Adjustments, Tab A30.

11. Vegetation Management

Q. WHAT ADJUSTMENT DID YOU MAKE REGARDING VEGETATION MANAGEMENT/TREE TRIMMING?

A. The Commission-approved settlement agreement in Docket No. E22-017 included normalized tree trimming based upon the five-year average of the actual expense. The same methodology has been followed and approved in our last two rate cases. Therefore, I applied the same methodology and replaced the 2024 actual year vegetation and tree trimmings costs with the average tree trimming costs for the five-year period from 2020 through 2024.

This adjustment impacts the 2024 pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 2, row 40, column 17,
- Schedule 9, page 1, row 35, column 5, and
- Volume 3, Section VIII Adjustments, Tab A31.

C. Amortizations

12. Prairie Island Indian Community (PIIC) Deferral

Q. PLEASE DESCRIBE THE PIIC DEFERRAL AMORTIZATION.

A. The Company has been deferring South Dakota customer's portion of the PIIC per the decision in Docket EL23-025 since January 1, 2024. To align with the life extension of the PI plants discussed above, we propose to begin collection of the total amount deferred from January 1, 2024 to December 31, 2025 over a term of three years consistent with rate case expenses.

This adjustment impacts the pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 2, row 40, column 19,
- Schedule 9, page 1, row 39, column 5, and
- Volume 3, Section VIII Adjustments, Tab A33.

13. NOL Tax Reform Regulatory Amortization

Q. PLEASE DESCRIBE THE NOL TAX REFORM REGULATORY AMORTIZATION.

A. The Commission's Order in Docket No. GE17-003 approved the Company's proposed amortization level included in the TCJA refund calculation. This is being amortized over 23 years.

This adjustment impacts the 2024 pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 2, row 40, column 18,
- Schedule 9, page 1, row 38, column 5, and
- Volume 3, Section VIII Adjustments, Tab A32.

14. Rate Case Expenses

Q. PLEASE DESCRIBE THE RATE CASE EXPENSES AMORTIZATION.

A. The Company requests approval of $1.324 million of projected direct expenses associated with this rate case docket and a three-year amortization period. This results in an annual amortization amount of $441 thousand. A three-year amortization period is consistent with our requested amortization period for other amortizations in this rate case.

This adjustment impacts the pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 2, row 40, column 20,

- Schedule 9, page 1, row 40, column 5, and
- Volume 3, Section VIII Adjustments, Tab A34.

D. Rider Removals

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

A. In this section, I present our proposed treatment of costs currently recovered in riders during the pro forma year period, including costs which we propose to continue to collect through the riders and costs we propose to move to base rates.

Q. WHAT RIDER MECHANISMS ARE CURRENTLY USED BY THE COMPANY?

A. The Company currently uses four cost recovery riders,

- Infrastructure Recovery Rider,
- Transmission Cost Recovery (TCR) Rider,
- Demand Side Management (DSM); and
- Fuel Cost Rider (FCR).

Q. WHAT IS THE COMPANY PROPOSING WITH RESPECT TO THE TREATMENT OF COSTS RECOVERED THROUGH RATE RIDERS?

A. The Company proposes:

- Continue recovery of costs for two capital projects with phased in-servicings, as well as ongoing and future infrastructure projects.
- Cost for 78 existing Infrastructure Rider projects will be moved to base rates effective January 1, 2026.
- Continued use of the TCR Rider for recovery of costs for one capital project with phased in-servicing, as well as ongoing and future transmission projects and MISO RECB Schedule 26 and 26A net

revenues. Costs for fully completed and in-service projects will be moved to base rates effective January 1, 2026.

- Continued use of the DSM in its current form.
- Continued use of the FCR in its current form.

These proposals are consistent with the rider filings we made during 2024 in our separate rider dockets.

Q. WHAT IS THE COMPANY'S ESTIMATED RIDER REVENUE BY RECOVERY METHOD IN THE 2024 PRO FORMA YEAR?

A. The rider revenue recovery included in the pro forma year is shown in Table 5 below.

Table 5
Cost Recovery of Rider Projects
($ in millions)

	Inf. Rider*	TCR Rider
2024 Revenue	($0.7)	$0.5
Less: Rider Removals	(19.3)	(0.7)
Total Rider Revenue	$18.6	$1.2

*Negative revenue amounts are due to PTCs and RECB.

15. Infrastructure Rider

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE INFRASTRUCTURE RIDER IN THE PRO FORMA YEAR?

A. As described earlier, we propose to:

- Continue recovery of costs for two capital projects with phased in-servicings, as well as ongoing and future infrastructure projects.
- Cost for 78 existing Infrastructure Rider projects will be moved to base rates effective January 1, 2026.

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE INFRASTRUCTURE RIDER IN THE PRO FORMA YEAR?

A. As described earlier, we propose to move 78 capital projects currently recovered in the Infrastructure Rider into base rates as part of the rate case. The Company made an adjustment to remove expenses, rate base and revenue for two projects in the pro forma year that will remain in the Infrastructure Rider. Support for the complete list of projects we propose to move to base rates can be found in Volume 3, Section VIII Adjustments, Tab A35. As I mentioned earlier, the Company is proposing to continue use of the Infrastructure Rider going forward.

Q. PLEASE DESCRIBE THE INFRASTRUCTURE RIDER REMOVAL ADJUSTMENT.

A. The Infrastructure Rider removal adjustment removes all costs and revenues from the pro forma year jurisdictional cost of service for two capital projects with phased in-servicing and PTCs that will continue cost recovery or refund in the rider after the implementation of rates in this case. The other projects that will remain in the Infrastructure Rider do not have any revenue requirement impacts in the 2024 historical test period; therefore, no rider removal is necessary for those projects. The Infrastructure Rider pro forma year adjustment ensures no double recovery of these costs. The adjustment has a net zero impact on the pro forma year revenue requirements, as we expect full recovery in the Infrastructure Rider. Support for the adjustment can be found on:

- Schedule 6B, page 2, row 40, column 21,
- Schedule 9, page 1, row 43, column 5, and
- Volume 3, Section VIII Adjustments, Tab A35.

As stated above, we propose to move 78 fully in-serviced projects into base rates in this case. Thus, no adjustment to pro forma year costs is necessary for these projects.

16. TCR Rider

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE TCR RIDER IN THE PRO FORMA YEAR?

A. We are proposing continued use of the TCR Rider during the rate plan period, which includes transmission projects and MISO RECB Schedule 26 and 26A revenues and expenses. In our 2025 TCR Rider filing, we requested recovery for a total of 31 projects that to date have not yet been included in base rates. With this filing, the pro forma year reflects our proposal to move all fully in-serviced projects that are currently in the rider into base rates. The costs and revenues for the remaining ongoing transmission projects and MISO RECB would continue to remain in the TCR Rider. Support for the complete list of projects we propose to move to base rates and remain in the rider can be found in Volume 3, Section VIII Adjustments, Tab A31. As I mentioned earlier, the Company is proposing to continue use of the TCR Rider going forward.

Q. PLEASE DESCRIBE THE TCR RIDER REMOVAL ADJUSTMENT.

A. The TCR Rider removal adjustment removes all costs and revenues from the pro forma year jurisdictional cost of service for one capital project with phased in-servicing and the MISO RECB that will continue cost recovery in the rider after the implementation of final rates in this case. The ongoing projects that will remain in the TCR Rider do not have any revenue requirement impacts in the 2024 historical test period; therefore, no rider removal is necessary for those projects. The TCR Rider pro forma year adjustment ensures no double recovery of these costs. The adjustment has a net zero impact on the pro forma year revenue requirements, as we expect full recovery in the TCR Rider. Support for the adjustment can be found on:

- Schedule 6B, page 2, row 40, column 22,
- Schedule 9, page 1, row 44, column 5, and
- Volume 3, Section VIII Adjustments, Tab A36.

As stated above, we propose to move all fully in-serviced projects into base rates in this case. Thus, no adjustment to pro forma year costs is necessary for these projects.

E. Known and Measurable Adjustments

Q. DID YOU FURTHER ADJUST THE BASE 2024 DATA TO DEVELOP THE PRO FORMA YEAR?

A. Yes. I made additional pro forma known and measurable adjustments to the 2024 unadjusted test year data. These adjustments were made for various capital projects, insurance, property taxes, community payments and wages, and are necessary to have final rates reflect the cost of service at the time the final rates become effective.

Q. WHAT STANDARD DOES THE COMMISSION APPLY WHEN ASSESSING WHETHER TO MAKE AN ADJUSTMENT FOR A KNOWN AND MEASURABLE CHANGE?

A. The purpose of a rate case is to establish rates that reasonably reflect the revenues and expenses that will be experienced at the time rates go into effect. A historical test period, here 2024, is helpful for providing certainty as to past revenues and expenses but does not, by itself, reflect the revenues and expenses at the time rates go into effect in January 2026. Therefore, it is necessary to adjust the 2024 historical information to reflect known and measurable changes that will occur in 2025 and 2026. The process of using a historical test period adjusted for known and measurable changes occurring within 24 months after the end of the historical period is expressly authorized by Commission Rule 20:10:13:44, which provides in part:

> However, no adjustments shall be permitted unless they are based on changes in facilities, operations, or costs which are **known with reasonable certainty and measurable with reasonable accuracy** at the time of the filing and which will become effective within 24 months of the last month of the test period used for this section and unless expected changes in revenue are also shown for the same period. (Emphasis added.)

For the requested known and measurable changes, I provide discussion of the facts that make the project known with reasonable certainty and measurable with reasonable accuracy.

Q. HOW DOES THE COMPANY'S CAPITAL BUDGET PROCESS SUPPORT THE KNOWN AND MEASURABLE ADJUSTMENTS?

A. The capital planning process involves a bottom-up analysis of needs and priorities on the part of the business areas as they develop capital budgets for review and approval. In this process, achieving the balance of funding key strategic priorities, maintaining base operations, and minimizing impacts on customer rates is important. Once proposed, project expenditures are identified, developed, and reviewed in the context of the Company's overall resources and discussed at planning meetings to determine how projects should be prioritized, and which are ultimately included in an approved budget. We also assess overall cost levels in relation to inflation, which provides a helpful benchmark for reasonable increases.

This allows us to ensure the most important priorities are met while keeping overall costs reasonable.

Q. PLEASE DESCRIBE IN MORE DETAIL THE CAPITAL BUDGET PROCESS FOR BUSINESS AREAS.

A. Business areas develop a capital budget for each project, including capital expenditures, in-service dates, deferred taxes, depreciation expense, and other related costs. Business area management reviews the developing budgets several times during the budgeting cycle. These reviews may consider:

- the analysis of long-term trends,
- discussion of what costs should be reduced based on process efficiencies or changing business requirements,
- identification of cost pressures and business risks,
- emerging regulatory requirements, and
- alignment with strategic objectives.

The management reviews are intended to ensure the budget is a reasonable and representative forecast of costs for the budget period. Business area budgets are consolidated, and a full report of capital program spend, including program descriptions and budget assumptions, are sent to the Investment Review Committee (IRC). The IRC takes into consideration rate and customer impacts, cost pressures, emergent issues, priorities presented by the business areas, and areas of strategic and business risk to our stakeholders. They also consider regulatory requirements and operational needs at the state level, the financial position of the operating company, and key strategic decisions that need to be made in the near future. These overall reviews of expenditures at the corporate level are conducted to balance needs across business areas and develop and approve budgets necessary to support an appropriate portfolio of projects from an operating company perspective, and the work necessary to continue to provide safe reliable service to customers.

Q. WHAT OCCURS AFTER REVIEW OF A PROJECT BY THE IRC?

A. For projects having capital expenditures greater than $15 million but less than $25 million, the IRC may approve the project, seek more information, or request that the business area re-evaluate certain assumptions before the project is included in the Company's budget. For example, the IRC may request additional information regarding such questions as how the business area is optimizing spending and in-service plans, how proposals compare to business area priorities, what alternatives were considered, how proposals are consistent with overall business strategy, and risk issues. For projects having capital expenditures greater than $25 million, after review by the IRC, a project will either be recommended for presentation to the Financial Council for approval or the business area will be asked to re-evaluate various assumptions before proceeding in the budget governance process. In addition, the IRC reviews projects with variances of more than 15 percent from their original approval.

Q. IF A PROJECT OF THE STATED THRESHOLDS IS APPROVED BY THE IRC, WHAT PROCESS DOES THE FINANCIAL COUNCIL UNDERTAKE IN ITS REVIEW?

A. The same iterative process used up to this point is repeated at the Financial Council, meaning additional research and analysis may be required and/or budget adjustments made. At the conclusion of the Financial Council review sessions, the business areas make any resulting adjustments, the budgets are considered final, and the final budgets are presented to the Boards of Directors for approval.

Q. PLEASE DESCRIBE THE APPROVAL OF BUDGETS BY THE XCEL ENERGY AND NSPM BOARDS OF DIRECTORS.

A. After Financial Council review and approval, the five-year capital budget is presented to the Xcel Energy Board of Directors. This review is focused on the upcoming year, as well as major changes compared to the previous year's five-year budget. The Board of Directors also reviews and determines whether to approve any new projects with total project spend of $100 million or more, and any previously approved project that is seeking re-approval because of significant changes to overall spend.

As part of a separate process, the NSPM Board of Directors approves the upcoming year's total capital budget, all new projects greater than $100 million, and the upcoming year's O&M budget. Because members of NSPM's Board of Directors also hold seats on the Financial Council, they also review and approve the full five-year O&M and capital budgets as part of that separate process. Thus, the NSPM Board of Directors has multiple opportunities to review, question, and ultimately approve the Company's budget.

Q. HOW DOES THIS BUDGET PROCESS CONTRIBUTE TO THE REASONABLE CERTAINTY AND ACCURACY OF THE KNOWN AND MEASURABLE ADJUSTMENTS?

A. It is a robust and iterative process designed to balance needs across business areas and support an appropriate portfolio of projects necessary to continue to provide safe reliable service to customers. The intensive review of the capital budget by individuals with different roles and functions in the Company ensures that the capital budgets are of reasonable certainty and are as accurate as possible.

17. Capital Projects

Q. WHAT ADJUSTMENTS DID YOU MAKE WITH RESPECT TO CAPITAL PROJECTS THAT WENT INTO SERVICE IN LATE 2024 OR WILL GO INTO SERVICE IN 2025 OR 2026?

A. I made adjustments to reflect the 2026 revenue requirements for capital projects that went into service either late in 2025 or in 2026. The adjustments reflect the incremental revenue requirement cost components for 2026 over the revenue requirement cost components (*e.g.,* plant, reserve, deferred and depreciation), if any, already included in the 2024 unadjusted test year. This adjustment includes the Company's requested recovery for Sherco Solar 1 and 2 starting in 2026. Consistent with the Company's request in the Infrastructure Rider proceeding; the Company will address the costs for the 2023-2025 revenue requirements associated with these two Sherco projects in a future Infrastructure Rider filing now that the Company is providing the additional analysis requested by Staff to support the reasonableness of these projects.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL FOR SAVER SWITCHES.

A. Historically the Company has recovered the cost of saver switches in the DSM Rider. A subset of switches are past their useful life and the systems used to control them are nearing end of life. To maintain control for all the switches and operate them leveraging the networks built for carrying meter data in the advanced grid information system (AGIS), the Company is proposing to move the recovery of the devices to the base rates and record them as a regulatory asset with a book life of 15 years and a five-year MACRS life for tax. This proposal will allow for more timely replacement of the legacy switches and the annual customer impact will remain consistent with past practice. For administrative ease the adjustment is included as part of the capital projects K&M adjustment and workpapers.

Q. PLEASE DESCRIBE THE KNOWN AND MEASURABLE CAPITAL ADJUSTMENTS.

A. A description of each of the capital adjustments is shown in Schedule 10.

These adjustments impact the pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 2, row 40, column 25,
- Schedule 9, page 2, rows 53-68, column 5,
- Exhibit___(LJW-1), Schedule 11, and
- Volume 3, Section VIII Adjustments, Tab K&M1.

18. Excess Liability

Q. PLEASE DESCRIBE THE EXCESS LIABILITY ADJUSTMENT.

A. As noted in Company witness Krug's Direct Testimony, the insurance market is hardening for electric utilities, particularly regarding liability and conventional property insurance. This is partially a response by insurers to significant damages and liabilities that electric utilities have faced in recent years as a result of catastrophic wildfires. The excess liability 12-month policy renewal was on October 18, 2024 with premiums effective as of November 1, 2024. The adjustment calculates the full year impact of the 2024 policy renewal as well as the 2025 policy renewal that will be effective as of November 1, 2025, as compared to the 2024 actual year resulting in a 24-month known and measurable adjustment.

This adjustment impacts the pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 2, row 40, column 23,
- Schedule 9, page 2, row 51, column 5, and
- Volume 3, Section VIII Adjustments, Tab K&M2.

19. Property Taxes

Q. PLEASE DESCRIBE THE PROPERTY TAXES ADJUSTMENT.

A. Property taxes are incurred in the prior year and are paid out in the current year. Thus, property taxes incurred in 2024 and 2025 will be paid out in 2025 and 2026, respectively. This adjustment captures the expected incremental increase in property tax payments for 2026 compared to 2024.

This adjustment impacts the pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 2, row 40, column 24,
- Schedule 9, page 2, row 52, column 5, and
- Volume 3, Section VIII Adjustments, Tab K&M3.

20. PIIC Payment

Q. PLEASE DESCRIBE THE PIIC PAYMENT ADJUSTMENT.

A. As filed in the Supplement to Docket No. EL23-025, effective starting in 2024, the Company negotiated a settlement with PIIC to pay $7.5 million per year, plus $50,000 for each cask of fuel stored at the Prairie Island Nuclear Generating Plant (PINGP). This settlement was related to the application for extending the operating lives of the nuclear facilities that was filed in 2024. Since the per cask amount changes with each new cask placed into service, an adjustment is needed to reflect the actual cost for the 2024 pro forma year based on rates effective January 1, 2026.

This adjustment impacts the pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 2, row 40, column 26,
- Schedule 9, page 2, row 69, column 5, and
- Volume 3, Section VIII Adjustments, Tab K&M4.

21. Wage Adjustment

Q. PLEASE EXPLAIN THE WAGE ADJUSTMENT AND WHY IS IT CONSIDERED KNOWN AND MEASURABLE.

A. The Company develops a base pay budget using headcount and historic and market base pay increases as part of its regular budgeting process. This adjustment captures the increases in both Union and Non-Union wages developed in that budget.

The Company's base pay budget assumes a three percent increase for non-bargaining employees. Surveys from five different sources demonstrate that a three percent increase in base pay is comparable to what the market has been projecting recently. Wage increases are announced and implemented each March. Therefore, we know that the average increase for 2025 is 3.0 percent. We will not know the actual percent increase for 2026 until March of 2026; however, this adjustment assumes an additional three percent increase in 2026 as supported by the market surveys mentioned above.

We have completed contract negotiations with our union employees and the wage increases for both 2025 and 2026 are known and measurable. The increase for 2025 and 2026 is three percent per year. These wage increases were applied to the actual union labor costs for 2024 to arrive at the adjustment amount.

This adjustment impacts the pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 2, row 40, column 27,
- Schedule 9, page 2, row 70, column 5, and
- Volume 3, Section VIII Adjustments, Tab K&M5.

F. Secondary Calculations

Q. WHAT IS THE NATURE OF THE SECONDARY CALCULATIONS?

A. Secondary Calculations include an adjustment for Cash Working Capital and an adjustment for Net Operating Loss. In both cases, the adjustment is dependent on the cumulative effect of all the other adjustments in the case. The impacts of these adjustments are explained and quantified below. However, each adjustment will be recalculated once the final list of Commission-approved adjustments is complete to determine the final impact.

22. Cash Working Capital

Q. PLEASE EXPLAIN THE CASH WORKING CAPITAL ADJUSTMENT.

A. As discussed earlier in Section IV.D, Other Rate Base, the Company has incorporated a secondary calculation to apply the various revenue lag days and expense lead days to the various income statement components to result in the appropriate cash working capital rate base adjustment. All the adjustments made in developing the pro forma year affect the cash working capital requirements. As a result, it is necessary to recalculate the change in the cash working capital incorporating the effects of those adjustments. Once the final Commission-approved adjustments are known, the cash working capital balance will be recalculated, and this adjustment will be revised as necessary.

This adjustment impacts the pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 2, row 40, column 29,
- Schedule 9, page 1, row 47, column 5, and
- Volume 3, Section VIII Adjustments, Tab A37.

23. Net Operating Loss (NOL)

Q. PLEASE DESCRIBE THE COMPANY'S NOL POSITION.

A. The income tax determination is currently in a NOL position. This means that more deductions exist than are needed to bring current taxable income to zero. The Company also has federal tax credits that have been deferred and tracked for use in future periods. NOLs, unused tax credits, and the associated ratemaking treatment are discussed in detail earlier in my testimony in Section V.D.

Q. IS THE COMPANY PROPOSING AN ADJUSTMENT TO BASE RATES RELATED TO NOLS OR DEFERRED TAX CREDITS IN THIS CASE?

A. Yes. The Company is generating NOLs and federal tax credits DTAs during the pro forma year due to tax deductions exceeding taxable income and the amount of federal tax credits earned during the year. This is partially offset by PTC sales, but the net result is an increase in the DTA. 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 pro forma year revenue requirements by the amounts shown on:

- Schedule 6B, page 2, row 40, column 30,

- Schedule 9, page 1, row 48, column 5, and
- Volume 3, Section VIII, Tab A38.

Q. WERE ADDITIONAL REVENUES ASSOCIATED WITH A RATE INCREASE CONSIDERED WHEN CALCULATING THE IMPACT OF THE NOL ON THE PRO FORMA YEAR REVENUE REQUIREMENT?

A. Yes. The Company did include the additional revenues it is seeking in this proceeding when calculating the NOL adjustment.

Q. WHAT IS REQUIRED TO FINALIZE THE NOL ADJUSTMENT AT THE CONCLUSION OF THIS CASE?

A. Once all items of revenue and expense have been determined in this case, a recalculation of the NOL is necessary to determine the level of deductions that must be carried forward to a future period. As with the current determination, the recalculation at the end of the case will be affected by the tax depreciation deductions, annual deferred tax expense, and the accumulated deferred tax balance.

G. Rebuttal Adjustments

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION?

A. In this section, I provide details related to adjustments we identified during our final quality assurance reviews performed just prior to this filing. These adjustments reflect small changes we believe are necessary but that we identified after we finalized our cost of service and rate design. Therefore, we were not able to incorporate these adjustments into the COSS due to timing constraints. We propose to incorporate these adjustments into the 2024 pro forma year revenue requirement when we file Rebuttal Testimony.

24) Present Revenue

Q. WHAT IS THE PRESENT REVENUE ADJUSTMENT?

A. When completing final validations on rate design the Company found an issue that would decrease present revenue and increase the net incremental deficiency by $150,000 to $175,000. The Company will adjust present revenue and provide supporting documentation in its Rebuttal Testimony.

25. Sherco Storage

Q. WHAT IS THE SHERCO STORAGE ADJUSTMENT?

A. This adjustment is related to the K&M adjustment for Sherco Storage that reflected an estimated in-service date in late 2025. Since that time, Form Energy has delayed the expected project completion date to early 2027, thus the K&M adjustment no longer meets the 24-month adjustment period. The Company will remove the K&M adjustment and decrease the net incremental deficiency by approximately $350,000 in its Rebuttal Testimony.

26. Infrastructure Rider Removal

Q. WHAT IS THE INFRASTRUCTURE RIDER REMOVAL ADJUSTMENT?

A. The Company will adjust the rider removal in its Rebuttal Testimony to fully remove 2024 PTCs from base rates. While completing final validations, the Company identified the rider removal removed PTCs based on the 2024 general ledger balances. The year end PTC balance per the general ledger does not account for final allocators or final wind generation pertaining to 2024. To fully remove the 2024 PTCs as included in the Jurisdictional Annual Report from the pro forma year, an adjustment is required. The Company included the anticipated rebuttal adjustment in Volume 3, Section VIII Adjustments, Tab A35 and Volume 3, Section IV Revenue, Tab R1. The rider rebuttal adjustment has no impact on the net incremental deficiency.

VIII. COMPLIANCE MATTERS

Q. DID YOU REVIEW COMMISSION ORDERS AS PART OF THE DEVELOPMENT OF THE PRO FORMA YEAR REVENUE REQUIREMENT?

A. Yes. The following list briefly describes the various Commission Orders that were reviewed and addressed in preparing the pro forma year. The compliance matrix included as Exhibit___(ADK-1), Schedule 2 to the testimony of Company witness Krug documents show our rate case filing includes information submitted in compliance with these prior Commission orders.

A. Rate Moratorium

In the Commission-approved Settlement Stipulation in Docket EL22-017, the Company agreed to a rate moratorium such that the Company would not file a petition to increase base rates for electric service, for rates proposed to be in effect prior to January 1, 2026. This application proposes new rates to be in effect on January 1, 2026, and therefore we have complied with this requirement.

B. Post-Retirement Medical Benefits (OPEBs) – Pay as You Go

In Docket No. EL11-019, the Commission reaffirmed its position to not use accrual accounting and instead to use pay as you go as the appropriate mechanism for recovering the cost of OPEBs. We reflected that decision in our 2024 pro forma year and therefore no further adjustment is needed to conform to this requirement.

C. Non-Asset Based Margins

Non-asset based transactions are wholesale (trading) transactions undertaken to obtain margins from purchases and sales of energy unrelated to meeting the energy needs of our native load customers. The only transactions that qualify as non-asset based are third-party supplied electricity or financial transactions that are not required to meet the needs of our retail customers and that are resold. The Commission's approval of the Settlement Stipulation in Docket No. EL12-046 approved a sharing mechanism under which the Company provided 30 percent of the profit margins from non-asset trading to customers through the Fuel Clause Rider. We have complied with this requirement. The non-asset based margins are refunded to customers through the Fuel Clause Rider.

D. Moving Completed TCR Rider Projects to Base Rates

In Docket No. EL11-019, the Company was directed to move the costs of completed TCR projects into the base rate revenue requirement. As discussed earlier, 31 projects recovered in the TCR Rider went into service prior to January 1, 2025, and we are proposing to move those project costs into base rates in this rate case filing, which satisfies this requirement.

E. Moving Infrastructure Rider Projects to Base Rates

The Settlement in Docket No. EL12-046 directed us to move projects into base rates "in a future rate case." As discussed earlier, 78 projects recovered in the Infrastructure Rider went into service prior to January 1, 2025, and we are proposing to move those project costs into base rates in this rate case filing, which satisfies this requirement.

F. MISO Schedule 26 Costs

In the Settlement Stipulation approved by the Commission in Docket No. EL11-019, the Company and Commission Staff agreed that Schedule 26 expenses and revenues should be removed from the unadjusted test year and included for Commission review in the TCR Rider on a going forward-basis. We have complied with that requirement and propose continued cost recovery through the TCR Rider. Therefore, the TCR Rider Removal adjustment includes a removal of both Schedule 26 revenues and expenses.

G. Nuclear Fuel Outage Deferral /Amortization

The Company has used the Commission-approved nuclear fuel outage deferral/amortization methodology. That methodology was included in the 2024 unadjusted test year and, therefore, no further adjustment was necessary. We continue to support this mechanism as appropriate for addressing the otherwise large annual variance in cost. We can experience between one and three outages in any given year, and the deferral and amortization method smooths out those variances over the useful life of the refueling outages (generally between 18 and 24 months). Amortizing the costs over that longer period also dampens the effect of increasing refueling outage costs.

IX. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION TO THE COMMISSION.

A. I recommend that the Commission determine an overall retail revenue requirement of $333.2 million and an incremental revenue deficiency of $43.6 million or 15 percent, based on a pro forma year with known and measurable changes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.