Direct Testimony and Schedules
Michele A. Kietzman

Before the South Dakota Public Service 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___(MAK-1)

Capital Investments, Depreciation, and Nuclear Decommissioning

June 30, 2025

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michele Kietzman. My business address is 401 Nicollet Mall, Minneapolis, Minnesota 55401.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am employed by Xcel Energy Services Inc. (XES) as a Senior Manager of Capital Asset Accounting. XES is a wholly owned subsidiary of Xcel Energy Inc. and provides an array of support services to all of the operating utility subsidiaries of Xcel Energy Inc., including Northern States Power Company (Xcel Energy, NSPM, or the Company), operating in South Dakota. My Statement of Qualifications is attached as Exhibit__(MAK-1), Schedule 1.

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

A. First, I provide information regarding the Company's material capital additions since its last rate case, which was filed in 2022. I then support the underlying information for the calculation of the level of proposed depreciation expense effective January 1, 2026, which includes recommended changes to average service lives, remaining lives, net salvage rates, and depreciation rates, where applicable, for all Company assets used in providing electric service. I also support the Company's recommendation regarding nuclear decommissioning accruals. Unless otherwise noted, my testimony provides total Company information. Company witness Laurie J. Wold includes the South Dakota electric jurisdictional amounts in her pro forma year revenue requirement, which is a 2024 historical test year with 24 months of known and measurable changes.

Q. SPECIFICALLY, WHAT DO YOU ADDRESS IN YOUR TESTIMONY?

A. My testimony addresses three topics: historical capital additions, depreciation expense, and nuclear decommissioning expense. In the capital additions section, I discuss material additions which have occurred since the Company's last rate case. In the depreciation section, I present the depreciation changes proposed for the production, transmission, distribution, electric general and intangible, and common general and intangible assets. I discuss the depreciation statistics for all assets in the electric and common utilities. In the nuclear decommissioning section, I present updates to the underlying cost estimate, the fund earnings rates, and the escalation rate. In considering all these areas, it should be kept in mind that the Company's last rate case was filed in 2022 using a 2021 test year.

Q. WHAT IS THE IMPACT OF THE CHANGES YOU RECOMMEND FOR DEPRECIATION AND NUCLEAR DECOMMISSIONING?

A. The net impact of the changes I recommend with regard to depreciation and nuclear decommissioning expenses is $0.0 million on a South Dakota jurisdictional basis. This is because increased depreciation costs due to shorter depreciable lives and/or changes in net salvage for some assets are completely offset by decreases in other areas, including significant reductions resulting from extending the lives of the Company's nuclear generation facilities.

With regard to depreciation for Electric Production assets, I am proposing a decrease of $11.8 million at a total NSPM Company level and a decrease of $0.8 million for the South Dakota retail jurisdiction. The primary factors contributing to this decrease include, but are not limited to, extending the depreciable lives of: the Monticello and Prairie Island nuclear facilities, the Steam refuse derived fuel (RDF) production facilities Red Wing and Wilmarth, and Black Dog 5 natural gas fueled unit; which are partially offset by shortening the depreciable life of Allen S. King and Sherco Unit 3 to align with their announced retirement dates. Further, the electric transmission, distribution, and general (TD&G) assets accounted for a NSPM Company level depreciation expense increase of $13.4 million and a South Dakota jurisdictional increase of $2.3 million. The overall South Dakota jurisdictional increase in depreciation for TD&G assets is primarily driven by the distribution capital additions that are directly assigned to the South Dakota jurisdiction. The NSPM Company common utility assets expense decreased by $6.1 million and the associated South Dakota jurisdictional amount decreased $0.4 million.

These recommended depreciation changes were then applied to the plant and estimated accumulated depreciation balance (i.e., the depreciation reserve) as of January 1, 2026, which included a depreciation passage of time.

The nuclear decommissioning accrual decreased by approximately $1.1 million (South Dakota jurisdictionalized) from $2.8M to $1.7M. I am recommending the accrual level be set at $1.7 million primarily due to the proposed life extensions of the nuclear facilities, as discussed in more detail later in my testimony.

Table 1 below summarizes the Company's proposed test year depreciation expense changes.

Table 1
Test Year Depreciation Expense Changes

(in millions)	Total Company	South Dakota Jurisdictionalized
Electric Production	$ (11.8)	$ (0.8)
Electric TD&G	13.4	2.3
Common Utility Assets	(6.1)	(0.4)
Nuclear Decommissioning*	N/A	(1.1)
Total	$ (4.5)	$ (0.0)

*Nuclear decommissioning accruals are calculated at the jurisdictional level and not at the NSPM Total Company level.

II. CAPITAL ADDITIONS

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

A. In this section, I discuss the Company's historical capital additions for the period 2022 through 2024 (since the Company's last rate case).

Q. WHAT WERE THE COMPANY'S CAPITAL ADDITIONS IN THE PERIOD OF 2022-2024?

A. The Company placed into service capital additions totaling $4.4 billion in the historical period of 2022-2024. Exhibit__(MAK-1), Schedule 2, is a Plant-in-Service Roll forward for the period 2022-2024. Unless otherwise noted, my testimony provides total Company information. Company witness Wold includes the South Dakota electric jurisdictional amounts in her pro forma year revenue requirement.

Q. WHAT WERE THE PRIMARY DRIVERS OF CAPITAL ADDITIONS IN THE 2022-2024 PERIOD?

A. From 2022-2024, the Company made a wide variety of investments across its system. In particular, investments in initiatives and individual projects in the following areas were the primary drivers of the Company's capital additions: wind farms and solar generating units, transmission projects related to asset renewal and reliability requirement, electric general property service and IT projects, and investments in the nuclear generating fleet. Below, I provide more information about the Company's investments in each of those areas.

Q. PLEASE DESCRIBE THE COMPANY'S INVESTMENTS IN WIND AND SOLAR FARMS IN THE 2022-2024 PERIOD.

A. The Company invested over $1.0 billion to build and maintain approximately 2,500 megawatts (MW) of wind farms across the NSP System between 2022-2024. A significant portion of the wind generation additions consist of the repowering of already-approved wind generation facilities, and other projects that I understand have already been approved by the Commission in infrastructure rider proceedings. Additionally, the Company in-serviced the first of three solar generating units, Sherco Solar Unit 1, in October of 2024. Company witness Bixuan Sun discusses the Sherco Solar projects in her Direct Testimony.

Q. PLEASE DISCUSS THE COMPANY'S INVESTMENTS IN TRANSMISSION PROJECTS IN THE 2022-2024 PERIOD.

A. The Company invested $729.7 million in capital additions in the Transmission function, from 2022-2024. The primary driver of these additions, from 2022-2024, were within the major investment categories of Asset Renewal, Reliability

Requirement, and Communication Infrastructure, which together account for over eighty percent of the transmission investment in the period.

The Asset Renewal category is primarily for managing the health and performance of transmission assets. This includes planned replacement of aging transmission lines and substation equipment that have reached the end of their useful life and/or are exhibiting failure characteristics indicating imminent failure; unplanned replacement of lines or equipment damaged by storms; additions to, or replacement of, tools and equipment that support capital project additions; and asset relocations necessitated by road projects as one example.

There are multiple distinct transmission projects that support the Asset Renewal category, including a large number of Major Line Rebuild and Major Line Refurbishment projects that were placed in service in 2023 and 2024. For instance, in 2023, Transmission placed in service the Pipestone – Woodstock Major Line Rebuild Project located in southwest Minnesota. This project, which I understand has already been approved by the Commission in transmission cost recovery rider proceedings, involved rebuilding Line 0726, which is an approximately 14-mile long 69 kV transmission line that had not been rebuilt in over 65 years, its expected useful life.

The Company's investments in Reliability Requirement projects were steady from 2022 through 2024 as several larger projects were placed in service. The Reliability Requirement category projects are constructed to address NERC reliability standards. Compliance with NERC reliability standards is mandatory for all users, owners, and operators of the bulk energy system. FERC, NERC, and regional reliability entities monitor and enforce compliance. Like the Asset

Renewal category, there are also multiple distinct transmission projects in the Reliability Requirement category.

From 2022 through 2024, capital additions have been steadily increasing for Communication Infrastructure as the Company's transmission group has been working on in-servicing portions of the Communication Network Program. These capital investments in each individual Communication Infrastructure project is lower in comparison to other major categories of transmission additions, but the volume of projects raises this category to a driver in the 2022-2024 period. At the same time, Transmission's investments in Physical Security and Resilience have been declining as the Company previously made investments in addressing existing NERC Critical Infrastructure Protection security requirements.

Q. PLEASE DESCRIBE THE COMPANY'S INVESTMENTS IN ELECTRIC GENERAL PLANT FOR THE 2022-2024 PERIOD.

A. The Company invested $429.0 million in capital additions in the electric general plant function, from 2022-2024. The primary drivers of these additions, from 2022-2024, were Fleet-related assets, Property Services, and Information Technology (IT) investments which accounted for over half of the electric general plant function additions in the period.

Q. PLEASE DISCUSS THE COMPANY'S FLEET-RELATED 2022-2024 INVESTMENTS SINCE THE LAST RATE CASE, AND HOW THEY SUPPORT THE SERVICES OR FUNCTIONS OF THE COMPANY AND THE PUBLIC INTEREST.

A. The Company's "fleet assets" refers to the fleet of cars, trucks, trailers, construction equipment, and related assets such as garages and fuel depots that are used and necessary to support the Company's provision of safe and reliable services. Fleet assets are used because the construction, maintenance, and repair of the system necessitates travel to our various physical facilities and equipment networks. The Company also uses various types of construction equipment to perform the regular work of maintaining the safety and reliability of our electric distribution system.

Our fleet investments have included, and are planned to continue to include, replacements, additions, and repairs of our fleet assets, including vehicles, fuel infrastructure, and garage tools. Decisions to replace or add new vehicles are made based on the cost of ownership and maintaining current aging assets as compared to newer assets, to ensure the optimum balance of cost and reliability.

Some of the new fleet additions also include purchases to transition away from renting. Additional types of vehicles are needed to meet increased headcount and additional work. Garage tool investments include, among other things, the purchase and installation of cranes, air compressors, and other fleet service center infrastructure necessary to keep our fleet running smoothly.

Q. PLEASE DISCUSS PROPERTY SERVICES KEY 2022-2024 INVESTMENTS, WITHIN THE ELECTRIC GENERAL FUNCTION, SINCE THE LAST RATE CASE.

A. Property Services is responsible for operating and maintaining Company owned and leased sites for regional and headquarters offices, service centers, and call centers, though not power plants, substations, gas regulator sites, or transmission sites. Capital projects are required to build these sites as well as bring sites up to code and keep the asset in operation. I present a few of the many property services projects, in the 2022-2024 time period in more detail:

- Sioux Falls Service Center Property Acquisition – The Sioux Falls Service Center was limited for space to meet existing demands in a fast growing area. The Company explored relocating the facility to a larger site, but had the opportunity to acquire a neighboring parcel of property from Border States Electric. This project will renovate the existing facility and tie into the neighboring property.
- Chestnut Service Center Redevelopment Phase 1 – Re-development of an existing campus for greater efficiency. The construction will address deferred maintenance projects, code issues, space limitations for vehicle storage, equipment storage, labs, materials, warehousing, workspaces. This overall project includes demolition of several buildings beyond their useful lives, including any needed environmental cleanup, as well as construction of new facilities, including a new service center building and facilities to support service center functions that will remain at the existing campus. A portion of the project was in-serviced in 2024.
- The Marshall Operations Center Development is a new operations and control center.is a related project located in Minneapolis, MN. This addition includes the design, engineering, site development, and construction of an approximately 100,000 square foot commercial class B office building. The construction includes lower-level storage, 1st, 2nd, and 3rd floors, and parking for approximately 200 vehicles. A portion of the overall project was in-serviced in 2024.
- Belgrade Service Center is located in Belgrade, Minnesota. This project includes a new 12,600 square foot service center with a cold storage building. The service center is located on a previously undeveloped 5-7 acre site. This facility consolidates operations from other locations and will serve as a local field office for Electric operations.

Q. PLEASE DISCUSS IT KEY 2022-2024 INVESTMENTS, WITHIN THE ELECTRIC GENERAL FUNCTION, SINCE THE LAST RATE CASE.

A. The Company makes capital investments and incurs operating and maintenance costs for IT to support the Company's customer, security, financial, and operational needs. IT capital additions include hardware (desktop and laptop computers, servers, routers, phone systems, radio systems, microwave communication systems, and network equipment); software (computer programs), related technology infrastructure investments, and cybersecurity solutions that support Xcel Energy's corporate and operating companies' business operations. As an example, the Company invested $25.1 million in 2023 in a project to upgrade the critical energy management system supporting the monitoring and management of the bulk electric system. This system includes transmission system supervisory control and data acquisition (SCADA) and monitoring and control of generation resources, including dispatch, and is used for market participation and reliability coordination purposes.

Q. PLEASE DESCRIBE THE COMPANY'S NUCLEAR GENERATING FLEET.

A. Xcel Energy owns and operates three nuclear units: one unit in Monticello, Minnesota and two units at Prairie Island in Welch, Minnesota.

Monticello is a single-unit boiling water reactor rated for gross output at 671 MW that was originally licensed by the Nuclear Regulatory Commission (NRC) in 1970. The NRC approved a renewed license for the facility in 2006, allowing the plant to operate through 2030. In December 2024, the NRC approved a Subsequent License Renewal (SLR) application, allowing Monticello plant operation through 2050.

Prairie Island is a two-unit pressurized water reactor, with each unit rated at 550 MW gross output capacity. The NRC licensed Prairie Island's two units in 1973 and 1974, respectively. The initial operating licenses were set to expire in 2013 and 2014. In 2011, the NRC approved renewed licenses for Prairie Island Units 1 and 2, extending their operating lives until 2033 and 2034, respectively. The Company intends to file an SLR application with the NRC by the end of 2026. Approval of SLR will allow Prairie Island Units 1 and 2 to operate through 2053 and 2054, respectively.

Q. WHAT WAS THE COMPANY'S OVERALL INVESTMENT IN ITS NUCLEAR GENERATING FLEET IN THE 2022-2024 PERIOD?

A. The Company invested $400.4 million in its nuclear generating fleet in the period of 2022-2024.

Q. PLEASE SUMMARIZE THE COMPANY'S KEY INVESTMENTS IN ITS NUCLEAR FLEET IN THE 2022-2024 PERIOD.

A. In the 2022-2024 period, the Company invested in mandated compliance projects, such as safety measures required by federal regulators for various safety and reliability initiatives. The capital investments made during this time period occurred in the Reliability, Improvement and Dry Cask Storage major categories.

Q. PLEASE DISCUSS THE COMPANY'S INVESTMENTS IN THE NUCLEAR RELIABILITY AND IMPROVEMENT CATEGORIES IN THE 2022-2024 TIME PERIOD.

A. Reliability projects are meant to enhance equipment and generation reliability by reducing safety system unavailability and forced losses in production output.

The Company's nuclear plants have been in operation for over 50 years and require ongoing capital investment to maintain reliable operation through equipment upgrades and replacement. Improvement projects are designed to improve system and operational performance (for example, digital upgrades) and can reduce O&M costs. The Company undertook both reliability and improvement projects at Prairie Island and Monticello. They include the Prairie Island Unit 1 and Unit 2 baffle bolt and clevis bolt replacements, the Monticello Groundwater Monitoring, Hardening, and Mitigation projects, and the upgrade of intake traveling screens at Prairie Island.

Q. PLEASE DISCUSS THE COMPANY'S CAPITAL ADDITIONS FOR DRY-CASK STORAGE.

A. Dry Cask Storage projects are associated with on-site dry spent fuel storage and loading campaigns. Because the Federal Government has not yet identified a permanent, long-term spent fuel storage facility, the Company must store spent fuel on-site in the interim. The timing of spent fuel storage is also designed to enable a full core offload for each unit at any time. Investments included purchase of Dry Fuel Storage (DFS) casks and loading of spent fuel into casks.

III. DEPRECIATION

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

A. The Company is requesting a revision to its remaining lives, net salvage rates, retirement curves, and depreciation rates for its production, transmission, distribution, general, and intangible assets. This section details the changes and includes supporting information for the requested changes.

Q. WHAT IS DEPRECIATION?

A. The term "depreciation" is a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. Depreciation is a process of allocation, not valuation. However, the amount allocated to any one accounting period does not necessarily represent an actual loss or decrease in value that will occur during that particular period. The Company accrues depreciation on the basis of the original cost of all depreciable property included in each functional property group. On retirement, the full cost of depreciable property, less the net salvage value, is charged to the depreciation reserve.

Q. WHAT IS A NET SALVAGE RATE?

A. Net salvage is the difference between the gross salvage (what the asset or its remaining scrap was sold for) and the removal cost (cost to remove and dispose of the asset). If the removal cost exceeds gross salvage, net salvage is negative. Some plant assets can experience significant negative removal cost percentages due to the amount of removal cost and the timing of any capital additions versus the retirement. Salvage and removal cost percentages are calculated by dividing the current cost of salvage or removal by the original installed cost of the associated assets.

Q. WHY IS IT IMPORTANT TO SET THE RIGHT LEVEL OF DEPRECIATION EXPENSE IN A RATE CASE?

A. The goal in setting depreciation lives and rates is to match depreciation recovery with the useful lives of assets to ensure current customers are equitably paying for the cost of the asset over the period they receive benefits from the assets, avoiding intergenerational inequity. The proposed depreciation rates and associated level of depreciation expense presented reflects the depreciation cost of service and proposed rates effective January 1, 2026.

Q. WHAT CHANGES ARE YOU PROPOSING FOR APPROVED LIVES, NET SALVAGE RATES, RETIREMENT CURVES, OR DEPRECIATION RATES IN THIS CASE?

A. I propose several changes affecting depreciation expense for production assets due to changing the remaining life, updating the dismantling cost that is the basis of the negative net salvage rate, and a reserve reallocation. For transmission, distribution, general, and intangible assets, I propose changes to the average remaining life depreciation rates based on underlying changes to the average service life, retirement curves, and net salvage rates. I discuss the full scope of depreciation expense changes proposed in my testimony below; however, the major drivers to the proposed change in depreciation expense are as follows:

- *Steam Production,* the shortening of the depreciable lives at Sherco Unit 3 and Allen S. King and the proposed extension of the Red Wing and Wilmarth Refuse Derived Fuel facilities;
- *Nuclear Production*, extending the depreciable lives of the Monticello and Prairie Island 1 & 2 nuclear facilities to 2050 and 2054 respectively;
- *Other Production*, extending the depreciable lives of the Borders and Pleasant Valley wind farms, due to repowering of these already-approved facilities and the proposed reserve reallocations; and extending the lives for Black Dog 5 and Inver Hills; and
- *Transmission, Distribution, General, and Intangible (TD&G)*, updating new average service lives, retirement curves, net salvage rates, and depreciation rates for all assets in accordance with the most recent

depreciation study and requesting initial parameters for several new accounts or subaccounts of assets.

The depreciation expense changes are supported by several exhibits to my testimony. Exhibit___(MAK-1), Schedules 3-5 are related to the Electric Production segment. Schedule 3 is the 2024 Comprehensive Dismantling Study performed by TLG Services (TLG) on the Company's production assets (2024 Comprehensive Dismantling Study), which I discuss further below. Schedule 4 is a summary of the proposed remaining lives and net salvage rates for each plant by FERC account. Schedule 5 is a calculation of proposed net salvage rates and a comparison of net salvage rates currently approved compared to the proposed rates.

Exhibit___(MAK-1), Schedules 6-8 support the average service lives, net salvage rates, and retirement curves for the transmission, distribution, electric general, and common general assets, using plant and depreciation reserve balances at December 31, 2024. Schedule 6 is the 2022 Depreciation Study performed by Alliance Consulting Services (Alliance) on the Company's TD&G assets (the 2022 Alliance Depreciation Study), which I address in greater detail below. Schedule 7 is a summary of the currently approved and proposed average service lives, net salvage rates, depreciation rates, and retirement curve for segment by FERC account. Schedule 8 shows how the proposed depreciation rates were calculated.

As I noted above in Section I, unless specifically stated, all depreciation numbers discussed in my testimony are at total NSPM Company level. Company witness

Wold provides the South Dakota jurisdictional costs for the pro forma year in her Direct Testimony.

All the changes set forth in the depreciation schedules are summarized in Table 2, below, which shows the overall change to depreciation expense by functional class based on January 1, 2025 plant and January 1, 2026 estimated depreciation reserve balances.

Table 2
Summary of Depreciation Expense Change w/Reserve Reallocation

Functional Class	**Change in Depreciation Expense (Total Company, amounts in thousands)**	**Change in Depreciation Expense (SD Jurisdiction, amounts in thousands)**
Electric Utility		
Steam Production	$117,387	$8,265
Nuclear Production	(104,141)	(7,333)
Hydro Production	(1,422)	(100)
Other Production	(23,662)	(1,670)
Total Electric Production	($11,838)	($838)
Transmission	$ 7,265	$512
Distribution (SD Located Only)	1,426	1,426
Electric General	4,812	335
Electric Intangibles	(57)	(4)
Total Electric TD&G	$13,446	$2,268
Total Electric Utility	**$1,608**	**$1,431**
Common Utility		
Common General	($5,330)	($344)
Common Intangibles	(797)	(50)
Total Common Utility	**($6,127)**	**($394)**
Total Depreciation Expense Change	**($4,519)**	**$1,036**

A. Production Assets

Q. PLEASE DESCRIBE THE CHANGES TO PRODUCTION ASSETS AND HOW THIS IMPACTS DEPRECIATION EXPENSE.

A. For production assets, a remaining life method is used to determine depreciation expense, which is the current net plant adjusted for expected net salvage divided by the current remaining life. The remaining lives for the production assets were evaluated based on the Company's expectations for operating each unit at a generating station, with the common assets (those assets shared by all units) at the generating station assuming the remaining life of the longest-lived unit. The Company met with employees who are knowledgeable about the planning, construction, and operations at each facility. During these meetings, the Company reviewed each facility to:

- Understand the major overhauls, rebuilds, and routine construction projects performed in the past few years;
- Consider the scope of current and upcoming projects; and,
- Forecast the likelihood of the facility achieving the currently approved remaining life in light of the past, current, and near future projects.

The Company considers these items along with its plans presented in its resource planning as described by Company witness Sun, to understand the operational life of each facility and determine an appropriate remaining life that would be consistent with the likely actual life of a particular facility. Schedules 3-5 provide detail comparing depreciation expense using currently approved lives and net salvage rates set in 2022 versus using the lives and net salvage rates as proposed in this filing.

For the negative net salvage rates, the Company utilized the 2024 Comprehensive Dismantling Study (Schedule 3) for all steam, hydro, and other production electric generating plants.

Q. IN GENERAL, WHAT CHANGES ARE YOU PROPOSING FOR EXISTING REMAINING LIVES?

A. To begin its analysis of remaining lives, the Company incorporated a three year passage of time adjustment to the last Commission approved remaining lives of all facilities. The passage of time adjustment does not change the annual depreciation accrual, but simply reflects that the Company's production facilities as of January 1, 2025 have aged three years since January 1, 2022, when the depreciation expense was last updated for the Company.

The Company also adjusted remaining lives to align the terminal retirement date with current expectations. Remaining lives for depreciation purposes have not been updated for South Dakota rates since 2022. Given this passage of time, it is necessary for the Company to update remaining lives with current reality.

Changes to lives within the Steam Production function include:

- The Company proposes, in this proceeding, new remaining lives due to the announced retirements of the Allen S. King and Sherco Unit 3 plants from June 2037 to December 2028 and December 2034 to December 2030, respectively. Company witness Sun discusses NSP's resource planning decisions, including the planned retirements of Sherco Unit 3 and King, in her Direct Testimony. The Company is proposing to extend the lives and operations of our Red Wing and Mankato (Wilmarth) renewable RDF plants. These plants are slated for retirement in 2027 and the Company is proposing to extend the operating lives of these plants from 2027 to 2037.

Changes to lives within the Nuclear Production function include:

- The Company proposes to extend the lives of the Company's nuclear facilities. This is discussed in more detail in Company witness Sun's Direct Testimony. The currently authorized South Dakota retirement dates for the nuclear fleet are Monticello (2040) and Prairie Island & 2 (2034) and the proposed retirement dates are Monticello (2050) and Prairie Island 1 & 2 (2054).

Changes to lives within the Hydro Production function include:

- The Company intends to pursue several projects to extend the life of the Hennepin Island and Upper Dam Hydro facilities (Saint Anthony Falls). We will be pursuing a new license from the Federal Energy Regulatory Commission (FERC) beginning in the late 2020's with a 40-year license extension expected to be issued in 2034. In addition, several capital projects are to be completed to include replacement of the horseshoe dam flashboard system and a new trash rack raker. There is a tailrace project planned for the downstream side of the powerhouse to replace an aging support structure. There is also a plan to stabilize a downstream riverbank at the facility that has experienced erosion because of Mississippi River floods. There are other capital projects planned in the next 15 years to maintain Hennepin Island and Upper Dam Hydro facilities as a functioning generating facility.

Changes to lives within the Other Production function include:

- We are proposing to extend the life of Black Dog 5 from December 2031 to December 2042. The currently approved remaining life was conceived with a thirty-year lifespan, but we now have evidence that this type of installation is lasting upwards of forty years or more, which also aligns with other similar installations at the Company's Riverside and High Bridge facilities. We are also proposing to extend the life of Inver Hills 1-6, in this proceeding, from the currently approved retirement date of December 2026 to December 2029. We are proposing changes in the lives for the Borders and Pleasant Valley. Borders was extended from December 2040 to December 2049, and Pleasant Valley from December 2040 to December 2049. These extensions, for the wind farms, are driven by the Company's wind farm "repowering" projects which involve rebuilding wind generation facilities with new technology and bigger blades that will extend their life spans.

Table 3 below summarizes all the generating units, in-service, for which there are changes to remaining lives.

Table 3
Production Remaining Life Changes

Functional Class/Unit	Current depreciable end of life	Proposed Remaining Life (Years) as of January 1, 2026	Expected actual retirement date
Steam Production			
A.S. King	June 2037	3	Dec 2028
Red Wing	Dec. 2027	12	Dec. 2037
Sherco Unit 3	Dec. 2034	5	Dec. 2030
Wilmarth	Dec. 2027	12	Dec. 2037
Nuclear Production			
Monticello	Sep. 2040	24.8	Sep. 2050
Prairie Island 1 & 2	Apr. 2034	28.3	Apr. 2054
Hydro Production			
Hennepin Island	Feb. 2034	48.2	Feb. 2074
St Croix Falls	Dec. 2027	22	Dec. 2047
Upper Dam	Feb. 2034	48.2	Feb. 2074
Other Production			
Black Dog 5 (342-346)	Dec. 2031	17	Dec. 2042
Inver Hills	Dec 2026	4	Dec. 2029
Borders Wind	Dec. 2040	24	Dec. 2049
Northern Wind	Jan. 2048	32.1	Jan. 2058
Pleasant Valley Wind	Dec. 2040	24	Dec. 2049
Rock Aetna Wind	Dec. 2047	32	Dec. 2057

Q. ARE THERE NEW PRODUCTION ASSETS WITH NEW REMAINING LIVES?

A. Yes, the Company is proposing remaining lives for several new generation units.

- Blue Lake Units 9-11 will replace the retiring Blue Lake Unit 3 capacity with new Reciprocating Internal Combustion Engine generator (RICE) capacity. The project includes improvements to the existing Blue Lake Units 7 and 8. The project scope includes the installation of backup power generation, switchgear, controls upgrades, and various other required equipment. The conceptual design includes 28 MW of new reciprocating engine capacity; installation of new medium voltage switchgear with upgraded (or new) controls; installation of a redundant combustion turbine starting system; and completion of other site and equipment improvements. The reciprocating engines will use the existing site infrastructure including natural gas supply, fuel oil tanks, and interconnecting facilities.

- Sherco Solar 1, 2 and 3 projects will have a collective nameplate capacity of 710 MW. Company witness Sun discusses the Sherco Solar projects in her Direct Testimony.
- The Sherco Long Duration Battery Storage Pilot Project is a 10 megawatt (MW)/1,000 megawatt-hour (MWh) long-duration energy-storage pilot project at the Sherco facility site. The in-service date for the project was delayed until 2027 after the cost of service for this rate case was determined, and Company witness Wold discusses that issue in her direct testimony.

Table 4 summarizes the new generating units' proposed remaining lives.

Table 4
Remaining Lives on New Production Units

Functional Class/Unit	Remaining Life at 1/1/2026 (in years)	Estimated In-service Date	Proposed Retirement Date
<u>*Other Production*</u>			
Blue Lake Units 9-11	40.0	Dec. 2025	Dec. 2065
Sherco Solar Unit 1	33.8	Oct. 2024	Oct. 2059
Sherco Solar Unit 2	34.8	Oct. 2025	Oct. 2060
Sherco Solar Unit 3*	35.0	Aug 2026	Aug 2061

* The current estimated in-service date is presented in Table 4. The Company requests that the end-of-life become effective upon the actual in-service date + 35 years for Sherco Solar Unit 3.

Q. IN GENERAL, WHAT CHANGES WERE MADE TO THE PRODUCTION NET SALVAGE RATES?

A. Every five years, The Company commissions a dismantling study to determine net salvage rates for its production assets. The 2024 Comprehensive Dismantling Study is included as Schedule 3, and it is a site-specific cost estimate for all of the Electric Production assets, including Hydro Production assets. The main purpose of the 2024 Comprehensive Dismantling Study was to estimate the present-day costs for retiring and demolishing the facilities, also known as final removals of existing facilities. A complete list of the assumptions used in the cost estimates is included in my Schedule 3.

Q. WHAT CHANGES TO THE PRODUCTION NET SALVAGE RATES ARE BEING PROPOSED?

A. Except for a few units, the general trend is toward a more negative net salvage rate due to the increasing costs of removal. Schedule 5 is a comparison of present and proposed net salvage rates. To calculate the proposed negative net salvage rates, the Company took the dismantling cost estimate for the entire facility and allocated it to each unit. Once allocated to each unit, the unit dismantling cost is divided by the unit's plant balance at January 1, 2025 to get the negative net salvage rate for each unit. The proposed percent changes to the net salvage rates for production assets are summarized in Table 5 below.

Table 5
Production Net Salvage Rate Changes

Functional Class/Unit	Change in Net Salvage Rate %	Change in removal reserve by end of life (in millions)
Steam Production		
Allen S. King	-2.1	$15.1
Red Wing	-3.0	$2.5
Sherco Unit 1	0.0	$0.0
Sherco Unit 2	0.0	$0.0
Sherco Unit 3	-9.3	$76.4
Wilmarth	-1.6	$1.3
Hydro Production		
Hennepin Island	-1.0	$0.2
St. Croix Falls	-23.9	$0.5
Upper Dam	-1.9	$0.1
Other Production		
Angus Anson Units 2 & 3	3.4	($3.5)
Angus Anson Units 4	-11.0	$6.3
Black Dog Unit 5	-3.4	$15.9
Black Dog Unit 6	-18.6	$19.6
Blue Lake Units 1-4	0.2	($0.1)
Blue Lake Units 7 & 8	0.4	($0.4)
High Bridge	-0.4	$1.8
Inver Hills	0.2	($0.1)
Riverside	-2.8	$9.6
Blazing Star 1 Wind	-0.6	$1.9
Blazing Star 2 Wind	-0.5	$1.7
Border Wind	-0.6	$1.6

cont.

Table 5, cont.
Production Net Salvage Rate Changes

Functional Class/Unit	Change in Net Salvage Rate %	Change in removal reserve by end of life (in millions)
Community Wind North	-1.3	$0.4
Courtenay Wind	-0.4	$1.3
Crowned Ridge Wind	-0.9	$3.0
Dakota Range Wind	2.5	($10.1)
Foxtail Wind	-0.4	$1.0
Freeborn Wind	-1.8	$5.9
Grand Meadow Wind	-6.4	$8.5
Jeffers Wind	-4.8	$2.1
Lake Benton II Wind	0.8	($1.3)
Mower Wind	3.1	($6.4)
Nobles Wind	-8.5	$22.6
Northern WF	1.7	($3.1)
Pleasant Valley Wind	-0.7	$2.4
Rock Aetna	-0.8	$0.3

Q. FOR THE PRODUCTION ASSETS GOING INTO SERVICE AFTER THE 2024 HISTORICAL TEST YEAR, WHAT ARE THE RECOMMENDED NET SALVAGE RATES?

A. Please see Table 6below presenting the net salvage rates for new plants.

Table 6
Net Salvage Rates for New Plants

Unit	Proposed Net Salvage %
Blue Lake Units 9-11	-10.0%
Sherco Solar Unit 1	1.9%
Sherco Solar Unit 2	2.0%
Sherco Solar Unit 3	2.0%

Q. IS THERE ANY ADDITIONAL INFORMATION REGARDING COST OF REMOVAL THAT SHOULD BE DISCUSSED?

A. Yes, coal combustion residuals (CCR) are the by-product of burning coal in coal-fired power plants. The coal is the fuel, and the ash is the byproduct of the combustion process. In 2024, the EPA amended the 2015 regulations which govern how coal ash is managed. The Company's Environmental Team has been engaged in identifying any known CCR related remediations, where the Company expects to incur unanticipated additional removal costs. The total scope and impact of the amended regulations on future incremental costs has yet to be determined. The third-party dismantling studies which the Company commissions within every five years to estimate cost of removal do not include CCR costs in the total cost of removal. As a result, the proposed net salvage used for this rate case may be understated with regards to newly identified additional CCR costs. The Company anticipates that CCR costs may be included in cost of removal estimates in a future rate case depending on Company evaluations and the future of the regulations in question.

B. Theoretical Reserve and Reserve Reallocation

Q. WHY DOES THE COMPANY PROPOSE A RESERVE REALLOCATION AND WHAT IS THE IMPACT ON DEPRECIATION EXPENSE?

A. Reserve reallocation is when the book reserve is realigned among accounts within a functional group based on the theoretical reserve for each account within that function. The Company proposes to perform a reserve reallocation in this proceeding because it results in a reduction to book depreciation expense and levelizes the impacts to customers. The proposed reallocation shifts reserves within the other and steam functions. The primary drivers for the steam and other functions' reserve reallocations is the return of excess cost of removal recovered through rates from retired production facilities. The reallocations are based on prior approved reserve reallocation methodologies.

Q. WHAT IS THE THEORETICAL RESERVE IN A DEPRECIATION STUDY?

A. The theoretical reserve represents the portion of a property group's cost that would have been accrued as depreciation reserve if current expectations were used throughout the life of the property group for future depreciation accruals. The theoretical reserve for the asset group serves as a point of comparison to the book reserve to determine if the unrecovered investment of the asset and its removal cost are over or under-accrued.

Q. HOW IS THE THEORETICAL RESERVE DETERMINED?

A. In the depreciation study, NSPM computed theoretical reserves based on projected plant balances as of December 31, 2024. The theoretical reserve was then calculated using a reserve model that relies on a prospective concept relating future retirement and accrual patterns for property, given current life and salvage estimates. More specifically, the theoretical reserve of a property group was determined from the estimated remaining life of the group, the total life of the group, and estimated net salvage. This computation for the straight-line, remaining-life theoretical reserve ratio, involves multiplying the vintage balances within the property group by the theoretical reserve ratio for each vintage. The calculation used in the depreciation study is the same calculation the Company used to develop the depreciation rates used in the Company's most recent Electric Rate Case, which was Docket No. EL22-017.

Q. HOW DOES THE THEORETICAL RESERVE RELATE TO THE RESERVE ALLOCATION?

A. As part of the depreciation study, a depreciation reserve reallocation was performed, which is based on the theoretical reserves calculated in the depreciation study. If the accumulated book depreciation reserve as compared to the theoretical reserve results in some assets being over-recovered (a positive value when subtracting the theoretical reserve from the book reserve) and others being under-recovered (a negative value when subtracting the theoretical reserve from the book reserve) within the functional class or group, then this difference can be used to rebalance the accounts within the functional class or group using the reserve reallocation.

Q. DID YOU ALIGN THE COMPANY'S DEPRECIATION RESERVE WITH THE LIFE AND NET SALVAGE CHARACTERISTICS OF THE ASSETS IN EACH FUNCTION?

A. Yes. In the process of analyzing the Company's depreciation reserve, I observed that the depreciation reserve positions of the accounts were generally not in line with the life and net salvage characteristics found in the analysis of the Company's assets. To allow the relative reserve positions of each account within a function to mirror the life and net salvage characteristics of the underlying assets, I reallocated the depreciation reserves for all accounts within each function. Since the basis of the current depreciation rates incorporates different average service lives and net salvage percentages from the proposed parameters in this case, I believe reserve reallocation is the best approach based upon sound depreciation practice to resolve the differences in reserve position.

Q. DOES THE REALLOCATION OF THE DEPRECIATION RESERVE CHANGE THE TOTAL RESERVE?

A. No, the reallocation of the depreciation reserve does not change the total reserve. The depreciation reserve represents the amounts that have been collected as a systematic allocation of the cost of an asset over its useful life, including any net salvage that may be required to remove that asset from service upon retirement. The reallocation process does not change the total reserve for each function; it simply reallocates the reserve between accounts in the function. The reallocated depreciation reserves agree in total to the projected reserve balances at December 31, 2024.

Q. IS DEPRECIATION RESERVE REALLOCATION A SOUND PRACTICE?

A. Yes. Depreciation reserve allocation is a sound and recognized depreciation practice. The National Association of Regulatory Utility Commissioners endorsed the practice in its 1968 publication of Public Utility Depreciation Practices, explaining that reallocation of the depreciation reserve is appropriate "…where the change in the view concerning the life of property is so drastic as to indicate a serious difference between the theoretical and the book reserve."[1] Additionally, the 1996 edition of Public Utility Depreciation Practices states that "theoretical reserve studies also have been conducted for the purpose of allocating an existing reserve among operating units or accounts."[2]

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[1] Public Utility Depreciation Practices, published by the National Association of Regulatory Utility Commissioners, at page 48 (1968).

[2] Public Utility Depreciation Practices, published by the National Association of Regulatory Utility Commissioners, at page 188 (1996).

Q. WHY IS IT IMPORTANT FOR THE DEPRECIATION RESERVE TO CONFORM TO THE THEORETICAL RESERVE?

A. It is important for the depreciation reserve to conform to the theoretical reserve because this sets the reserve at a level necessary to sustain the regulatory concept of intergenerational equity among the Company's customers, as well as sets the depreciation rates at the appropriate level based on current parameters and expectations.

Q. PLEASE EXPLAIN HOW THE REALLOCATION OF DEPRECIATION RESERVES IS CONDUCTED IN THE DEPRECIATION STUDY.

A. To start, the total theoretical reserve for asset groups within each function is computed. Then, to reallocate depreciation reserves within each function using the theoretical reserve model, a proration factor is computed by developing a ratio of the total book reserve to the total theoretical reserve by functional class. After each theoretical reserve was computed, it is multiplied by the proration factor to derive the reallocated book reserve of each functional group. After computing the reserve reallocation, the recommended depreciation rates and expense were calculated in Schedules 4 and 7 for the Company's plant in service assets.

Q. ARE THERE ANY UNIQUE CIRCUMSTANCES WITH THE RESERVE REALLOCATIONS PROPOSED IN THIS PROCEEDING?

A. Yes. The primary reason the Company proposes a reserve reallocation in this proceeding is to appropriately credit cost of removal recovery of retired assets which directionally reduces customer rate impacts. As presented in Table 2 of my testimony, the current proposed change to the South Dakota jurisdictional depreciation expense, which incorporates reserve reallocations, is $1.1 million.

This is primarily driven by the electric distribution function which is direct assigned or projects solely related to South Dakota.

Q. ARE THERE ANY ADDITIONAL RESERVE REALLOCATIONS PROPOSED IN THIS PROCEEDING?

A. Yes. There are a few, much less material reserve reallocations in the Steam Production and Other Production functions to ensure full recovery of the plant and removal costs without impact to customer rates.

Q. PLEASE SUMMARIZE THE IMPACTS TO DEPRECIATION EXPENSE OF THE PROPOSED CHANGES FOR PRODUCTION ASSETS DESCRIBED ABOVE.

A. All of these changes are summarized in Table 2, above, which shows the overall $11.8 million NSPM Total Company decrease and $0.8 million South Dakota jurisdictional decrease to depreciation expense by functional class based on January 1, 2025 plant and estimated depreciation reserve balances as of January 1, 2026. Company witness Wold provides the revenue requirement impact of these changes for the pro forma year in her Direct Testimony.

C. TD&G Assets

Q. WHAT ARE TD&G ASSETS?

A. TD&G assets refer to all assets in the transmission, distribution, and general functional classes of assets. General assets can be either electric utility only (e.g. communication equipment which specifically supports only the electric segment) or common utility (e.g. a service truck which can be deployed to support either gas or electric repairs). Common utility assets are allocated out to the electric and gas segments based on various allocation methods.

Q. WHAT IS THE PURPOSE OF A TD&G DEPRECIATION STUDY?

A. A TD&G depreciation study is a comprehensive analysis of all TD&G assets in order to determine the statistical parameters for each account or group of assets to set depreciation rates and lives. The TD&G depreciation study encompasses four distinct phases. The first phase involves data collection and field interviews. The second phase is an initial data analysis. The third phase evaluates the information and results of the initial analysis. Finally, the fourth phase involves the calculation of depreciation rates and documenting the corresponding recommendations.

Q. WHEN WAS A TD&G DEPRECIATION STUDY LAST PERFORMED?

A. The Company directed Alliance Consulting Group to perform a comprehensive TD&G depreciation study, the 2022 Alliance Depreciation Study, for the TD&G assets for the electric, gas, and common utilities. This study is performed every 5 years so the next study will be performed in 2027. Although gas assets were included in the 2022 Alliance Depreciation Study, they are not part of this proceeding. All Company assets were included in the 2022 Alliance Depreciation Study regardless of where they were located. The 2022 Alliance Depreciation Study is included as Schedule 6.

In the 2022 Alliance Depreciation Study, the Company reviewed the depreciable lives and net salvage rates for TD&G assets. The analysis included interviews with operating personnel responsible for purchase, maintenance, and utilization of the equipment. For the 2022 Alliance Depreciation Study, the lives were adjusted if factors such as market forces, manufacturer expected life, technological obsolescence, business planning, known causes of retirement, and changes in expected future utilization affected the useful life of the asset.

Q. PLEASE PROVIDE AN OVERVIEW OF THE ANALYSIS THAT WAS DONE TO DETERMINE DEPRECIATION RATES FOR TD&G ASSETS.

A. The 2022 Alliance Depreciation Study was only used for the resulting statistics (average service life, net salvage rate, and retirement curve) and not for the determination of the depreciation rate. The calculation of the average remaining life depreciation rate was done by Company personnel using the South Dakota depreciation reserve in conjunction with the depreciation statistics from the 2022 Alliance Depreciation Study. The 2022 Alliance Depreciation Study is included as Schedule 6. Schedule 7 compares the presently approved depreciation rates and parameters to the proposed values. The depreciation rate calculation is shown in Schedule 8.

Using the 2022 Alliance Depreciation Study, the Company proposes new depreciation lives, net salvage rates, retirement curves, and depreciation rates for TD&G assets in this filing to better reflect the expected useful lives of its assets as well as removal costs and expected salvage. In general, depreciation lives remained mostly the same and net salvage rates are becoming more negative due to increasing removal costs and decreasing gross salvage values. The Company also continues the use of an Average Remaining Life (ARL) method. This method allows an automatic true-up of differences created between the theoretical and actual reserves over the remaining lives of the assets.

Q. PLEASE DISCUSS THE REVISED THEORETICAL RESERVE AMOUNTS IN THE 2022 ALLIANCE DEPRECIATION STUDY, AT THE END OF SCHEDULE 6.

A. During review of the theoretical reserve accounts in connection with a relevant Minnesota Public Utilities Commission docket, the Company identified a number of incorrect linkages in the associated theoretical reserve tabs in the Appendices to the 2022 Alliance Depreciation Study.[3] The Company corrected these linkages and provided the corrections in a relevant discovery response (the response to Information Request No. 37).[4] It is the corrected amounts set forth in that discovery responses that the Company used in its calculations, and a copy of the document is attached to the end of 2022 Alliance Depreciation Study, Schedule 6, at page 196. It should be noted that the 2022 Alliance Depreciation Study parameters and assumptions language is correct, and only those initial supporting workpapers were found to have errors.

Q. PLEASE DISCUSS THE PROPOSED CHANGES IN SERVICE LIVES, AS A RESULT OF THE 2022 ALLIANCE DEPRECIATION STUDY.

A. The 2022 Alliance Depreciation Study provides detailed information on the proposed changes in lives and the justification for those changes. In summary, for electric transmission, distribution and general plant accounts, there are 47 accounts: three have increasing lives, five have decreasing lives, two are newly proposed, and 37 accounts were unchanged. The account for which the proposed change in life caused the greatest change in the annual accrual is FERC Account 366 – Underground Conduit. The life was lengthened 11 years for a proposed life of 67 years. For the 23 common general plant accounts: one

[3] 2022 Transmission, Distribution, and General Accounts & Five Year Transmission, Distribution, and Gas Depreciation Study, MPUC Docket No. E,G002/D-22-299.
[4] Minnesota Department of Commerce Information Request No. 37, Docket No. E,G002/D-22-299.

has an increase in life, one has a decrease in life, and 21 accounts were unchanged.

Q. PLEASE DISCUSS THE PROPOSED CHANGES IN NET SALVAGE RATES RESULTING FROM THE 2022 ALLIANCE DEPRECIATION STUDY.

A. The 2022 Alliance Depreciation Study provides detailed information on the proposed changes in net salvage rates and the justification for those changes. In summary, for electric transmission, distribution and general plant accounts, three accounts increased their net salvage (i.e., more positive), two accounts are decreasing but remain positive, 16 accounts have increasing negative net salvage (i.e., more negative), two are newly proposed, and 24 accounts remain unchanged. The largest variance of approved net salvage to proposed net salvage rates was a 15 percent reduction which occurred in three electric accounts. The accounts impacted are transmission FERC Account 354 Towers and Fixtures and distribution FERC Account 364 Poles, Tower, and Fixtures, and FERC Account 369 Overhead Services. For the 23 common general plant accounts, there are no proposed net salvage rate changes.

Q. IS THE COMPANY PROPOSING TO CONTINUE THE USE OF AVERAGE REMAINING LIFE DEPRECIATION RATES FOR TD&G?

A. Yes.

Q. WERE THERE ANY ADJUSTMENTS IDENTIFIED DURING FINAL REVIEWS THAT REQUIRE UPDATES TO PROPOSED TD&G RATES?

A. Yes. During our final quality assurance reviews performed just prior to this filing, it was identified that the rate proposed for Electric and Common Account 390 – Structures and Improvements was calculated including specific buildings that should have been excluded. This results in a small change which is necessary to correct, but was not incorporated into this filing due to timing constraints. The Company will incorporate this adjustment in Rebuttal Testimony.

D. Legacy Meter Recovery

Q. PLEASE PROVIDE BACKGROUND RELATED TO LEGAL METERS RECOVERY.

A. The Company is in the process of replacing our legacy Automated Meter Reading (AMR) meters or "legacy meters" with Advanced Metering Infrastructure (AMI) meters. Company witness Brandon T. Cramer discusses the status of the meter replacement in his testimony; my testimony focuses on proposing a recovery mechanism for the legacy meters not yet fully depreciated at time of AMI deployment. It is reasonable for the Company to recover prudent capital investments, such as the AMR or legacy meters.

Q. WHAT IS THE COMPANY'S PROPOSAL FOR RECOVERY OF LEGACY METERS?

A. The Company proposes to include any undepreciated amounts for legacy meters in a regulatory asset (with a return at WACC) and amortize such regulatory asset over the remaining authorized depreciable life of the meters. The creation of such regulatory asset and its amortization period would allow for return of and return on the undepreciated amount to be reflected in base rates as a result of this rate case.

Q. ARE BOTH THE AMR AND AMI METERS READILY IDENTIFIABLE ON THE COMPANY BOOKS?

A. Yes, the Company has already separated the meters into FERC sub-accounts, which allows the new AMI meters to be capitalized and depreciated separate from the legacy meters which are being retired.

Q. WHAT WOULD BE THE REQUIREMENTS FOR THIS TYPE OF REGULATORY DEFERRAL?

A. In order to support a regulatory asset in future amortization of these costs, the Company would need an Order from the Commission allowing the deferral of these costs as well as approving the amortization rate for the AMR meters in future periods.

IV. NUCLEAR DECOMMISSIONING TRUST

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

A. This section addresses the changes to the calculation of the nuclear decommissioning accrual that have occurred since the Company's last rate case, filed in 2022. There is a new engineering cost estimate, updated escalation and earnings rates, and current bank balances.

Q. WHAT IS THE NUCLEAR DECOMMISSIONING ACCRUAL?

A. Nuclear decommissioning accrual is the method used to accumulate the final removal costs for the Company's three nuclear units. The amounts collected through general rates are deposited externally in a trust fund pursuant to Nuclear Regulatory Commission (NRC) rules. The annual accruals are calculated based on a detailed engineering cost estimate for removal of the plant and storage of the fuel until the federal government takes possession of all the fuel assemblies. These accruals are then invested by professional asset managers in a risk-mitigating strategy to increase the accrued amount while hedging losses.

This is in contrast to how the Company addresses dismantling costs for its other production assets, where the dismantling costs are not segregated into a trust account nor invested.

Q. WHAT CHANGES ARE YOU RECOMMENDING?

A. The Company is proposing to decrease the annual nuclear decommissioning accrual for the South Dakota jurisdiction from $2.8 million set in Docket EL22-017 to $1.7 million in this proceeding. Nuclear decommissioning accruals are calculated at the jurisdictional level and not at the total NSPM Company level. This accrual is calculated for a 60-year DECON scenario, which is in line with NSPM's other jurisdictions, and is the industry requirement from the NRC. The DECON decommissioning scenario is one in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed or decontaminated to a level that permits the property to be released for unrestricted use shortly after cessation of operations.

Q. HOW IS THE NUCLEAR DECOMMISSIONING ACCRUAL AMOUNT DETERMINED?

A. Using an engineering cost study for the basis of decommissioning costs, the Company partners with Goldman Sachs Asset Management (GSAM), the trust fund administrators, to obtain labor and non-labor escalation rates as well as operational and post-shutdown earning rates on the fund for each of the nuclear units throughout the decommissioning of each facility.

Q. WHAT IS CAUSING THE NUCLEAR DECOMMISSIONING ACCRUAL TO DECREASE?

A. The primary driver in the decrease of the decommissioning accrual is the proposed life extensions of the nuclear facilities. The current accrual assumes Monticello (2040), Prairie Island 1 (2033) and Prairie Island 2 (2034) estimated retirement dates, whereas the proposed accrual assumes estimated retirement dates of Monticello (2050), Prairie Island 1 (2053) and Prairie Island 2 (2054). These life extensions align with the Company's resource planning and relicensing efforts for the plants which are further discussed in Company witness Sun's testimony. The current accrual was used in the 2022 rate case and was based upon the 2020 cost study. This proceeding uses the 2024 cost estimate. The study was performed in 2024 and provided costs in 2024 dollars. Both the 2020 and 2024 studies were prepared by TLG Services, the engineering consultant the Company has historically used to prepare these estimates (the 2020 and 2024 TLG Decommissioning Studies, respectively). TLG Services has extensive industry experience and currently provides estimates for the majority of nuclear production plants in the country. A comparison of the nominal cost estimates to decommission are in Table 7 below. There was also a decrease in the earnings assumption of the trust in addition to the revised decommissioning assumptions and life extensions.

Table 7
Nominal Cost Estimate to Decommission

Year of Study	Monti	PI1	PI2	Total
2020	$1,618,023,164	$1,017,864,701	$1,029,940,789	$3,665,828,655
2024	$1,938,370,145	$1,224,787,888	$1,229,630,788	$4,392,788,821
Change in Estimate	$320,346,981	$206,923,187	$199,689,999	$726,960,167

Q. WHAT EARNINGS AND ESCALATION RATES ARE BEING USED TO CALCULATE THE NUCLEAR DECOMMISSIONING ACCRUAL?

A. The accrual calculation is run on each unit using two single effective earnings rates, one rate for the operating period (radiological) and one for the post-shutdown period (spent fuel/site restoration). These rates, which reflect the anticipated amount of investment proceeds the Company expects to earn on the funds in trust, are calculated and provided by GSAM, based on asset allocation recommendations made at the same time as the development of the 2024 cost estimate. The operating period rates are 5.01 percent for Monticello, up from 3.92 percent in 2020; 5.00 percent for Prairie Island Unit 1, up from 3.94 percent in 2020; and 5.02 percent for Prairie Island Unit 2, up from 4.02 percent in 2020. The post-shutdown period rates are 4.87 percent for Monticello, up from 3.30 percent in 2020; 4.72 percent for Prairie Island Unit 1, up from 2.98 percent in 2020; and 4.79 percent for Prairie Island Unit 2, up from 2.90 percent in 2020. Cost escalation rates were also provided by GSAM. The cost escalation rates in the 2024 study are 4.50 percent for labor costs and 3.30 percent for non-labor costs. This is not directly comparable to the Operations rate of 4.22 percent and the post decommissioning rate of 3.02 percent that was used in the 2020 TLG Decommissioning Study, but it uses the same base assumptions around inflation and wage increase rates.

Table 8
Earnings Rates Changes

Nuclear Unit	Period	2020 Return	2024 Return	Change
Monticello	Pre-decommission start	3.92%	5.01%	1.09%
Monticello	Post-decommission start	3.30%	4.87%	1.57%
PI Unit I	Pre-decommission start	3.94%	5.00%	1.06%
PI Unit I	Post-decommission start	2.98%	4.72%	1.74%
PI Unit II	Pre-decommission start	4.02%	5.02%	1.00%
PI Unit II	Post-decommission start	2.90%	4.79%	1.89%

Q. WHAT IS THE BALANCE FOR SOUTH DAKOTA IN THE QUALIFIED TRUST?

A. The accrual calculation uses qualified trust balances as of December 31, 2024. The market value of the fund, net of expected taxes on unrealized gains, for each unit for the South Dakota jurisdiction is the starting point for each unit's accrual calculation. Exhibit___(MAK), Schedule 9, shows the balances of the funds as of December 31, 2024 used to calculate the accrual, and Table 9 shows the balance by unit.

Table 9
Qualified Trust Fund Balance by Unit
December 31, 2024

Monticello	$48,583,019
Prairie Island 1	34,966,683
Prairie Island 2	38,164,267
Total	$121,713,969

Consistent with the Company's 2012 Filing in Docket No. EL12-046 regarding the then-existing nuclear decommissioning escrow account, the beginning balance of the trust also includes the pour-over of the then-existing escrow funds. In addition to the South Dakota jurisdictional fund balances, past wholesale balances are expected to be reallocated across all jurisdictions. When this reallocation occurs, South Dakota will realize a benefit for these dollars as they impact the beginning balance of future decommissioning accruals.

Q. DOES THE COMPANY'S TREATMENT OF THE NUCLEAR DECOMMISSIONING ACCRUAL REQUESTED IN THIS PROCEEDING ALIGN IT WITH ITS OTHER JURISDICTIONS?

A. Yes. The Company has committed to using cash flows from the 2024 cost study by TLG Services and cost escalation rates provided by GSAM in the ongoing Minnesota (Docket No. E002/M-24-320), and North Dakota (Docket No. PU-24-376) electric rate cases. I note that our proposal includes an amount of contingency as consistent with industry practice to account for market volatility.

Q. WHAT IS THE END-OF-LIFE (EOL) NUCLEAR FUEL ACCRUAL?

A. The EOL Accrual is a cost recovery mechanism that reserves for the unspent and unamortized nuclear fuel that is in the reactors at the time the nuclear reactors are shut down. These reserves accrete over the life of the plant through a periodic expense, similar to other end of life and removal reserves.

Q. HOW DOES THE END-OF-LIFE (EOL) NUCLEAR FUEL ACCRUAL WORK?

A. The EOL Accrual and Decommissioning Accrual both function by setting funds aside for known future obligations. However, the EOL Accrual is different in that its funds are held within the Company as opposed to a separate trust. Because of this, there is an offset to rate base for the cumulative EOL funding. Customers receive offsetting benefit from this funding through a reduction in rate base and in the resulting reduction in general rates.

The intent of EOL recovery is that the cumulative effect of the accrual and corresponding rate base reduction will maintain a constant annual net cost to customers over time. The EOL rate base reduction and accruals collected are put into rates in the Company's general rate case filings. At that point, both are in parity – meaning that for the first year the customer pays the full accrual amount and receives the full benefit of the rate base impact through rates. However, in future years the customer needs to be compensated for the additional offset to rate base that it should receive for the contributions it has made since the general rate was approved. To compensate for this, the assumed accrual increases to an amount that includes the rate base impact the customer should receive. In this way, the customer is credited for the benefit they should receive by essentially investing the assumed return into the EOL fund balance. As such, every year that passes, the assumed accrual will increase without an increase to rates, to compensate for the assumed interest until another general rate case is filed and ordered on. At this point, the higher accrual is put into rates, offset by a larger rate base offset.

Q. IS THE COMPANY PROPOSING A REVISION TO THE EOL NUCLEAR FUEL ACCRUAL IN THIS CASE?

A. Yes. Based on updated assumptions around the cost of fuel and the how the fuel will be used in the reactors, the amount the Company needs to recover has decreased from the last approved filing. We propose a Total Company EOL accrual amount of $661,152, which is a decrease in the Total Company value of $595,944 from previous levels.

V. FERC ORDER 898

Q. PLEASE SUMMARIZE FERC ORDER 898.

A. FERC Order 898 is the final rule by which the FERC is amending the Uniform System of Accounts for public utilities and licensees to:

- create new accounts for wind, solar, and other renewable generating assets;
- create a new functional class for energy storage accounts;
- codify the accounting treatment of environmental credits; and
- create new accounts within existing functions for computer hardware, software, and communication equipment.
- FERC is also amending the relevant FERC forms to accommodate these changes. FERC Order 898 was effective January 1, 2025.

Q. ARE THERE ANY ACCOUNTS WHERE THE COMPANY IS PROPOSING A CHANGE IN DEPRECIABLE LIVES?

A. No. The Company is not requesting any changes in asset depreciable lives as a result of the FERC Order 898 adoption. Any future changes in depreciable lives will follow established regulatory processes.

Q. HOW WILL FERC ORDER 898 IMPACT THE FUTURE ELECTRIC AND GAS PRODUCTION, ENERGY AND GAS STORAGE PLANT ANNUAL DEPRECIATION EXPENSE?

A. The Company does not anticipate that the implementation of FERC Order 898 will impact future depreciation expense for production-related assets. There will be reclassifications from the current FERC accounts into the newly created FERC Order 898 accounts, but this will not change their associated depreciation parameters, such as net salvage percent or retirement dates. For example, wind production assets, which currently reside in the Other Production function and FERC account series (340-348), will be reclassified to a new functional class: Wind Production FERC account series (338.20-338.34). When this transfer of assets occurs, it will not change the currently approved depreciation parameters. In addition to the new Wind Production functional class, FERC Order 898 has created production related assets for Solar Production FERC account series (338.1-338.13), Other Renewable Production FERC account series (339.1-339.13), and Energy Storage Plant FERC account series (387-387.12). Lastly, and described below in more detail, the production related assets post-FERC Order 898 implementation, will include new subaccounts for assets that directly support their respective functional classes, such as computer hardware, software, and network equipment.

Q. WHAT IS THE MOST SIGNIFICANT IMPACT OF FERC ORDER 898 ON THE TREATMENT OF TD&G RELATED ASSETS?

A. The most significant impact to TD&G assets is the direct assignment of computer hardware, software, and network equipment to functional classes they directly support. This includes current and new FERC Order 898 plant functional classes: production, transmission, distribution, regional transmission and market operations (new), energy storage (new), and general. In situations where hardware, software, network and communication equipment do not have a single primary functional class they support, they will remain in an electric general function and follow the currently approved allocators. This is also the case for any hardware or software that supports both electric and gas utilities. Currently, computer hardware, software, and network equipment reside in either the electric, gas, or common utility Intangible Plant function. Post-FERC

Order 898 implementation, some of these assets will be directly assigned to the functions they serve. For example, computer software that supports the Steam Production function will now reside in the Steam Production functional class and be assigned the new FERC Order 898 subaccount 315.2 Computer Software. Currently, this computer software resides in Electric Intangible Plant FERC Account 303.

Q. ARE THERE POTENTIAL DEPRECIATION IMPACTS RELATED TO THE IMPLEMENTATION OF FERC ORDER 898 ON TD&G RELATED ASSETS?

A. There are no potential depreciation impacts related to the implementation of FERC Order 898 related to TD&G assets. There will continue to be a direct relationship between current and newly-created FERC accounts, and therefore there are currently no proposed changes to depreciation parameters such as average service lives, net salvage rates, and retirement curves.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company has made considerable investments in the NSP System since the last rate case was filed in 2022. The Company must update its depreciation expense given the passage of time and other developments since its last rate case. The changes in its depreciation expense are consistent with current known and assumed remaining lives of its production plant, currently known net salvage rates, and other considerations. Additionally, the Company's proposed TD&G depreciation rates are consistent with appropriate studies and conform to past practice. Overall, the Company's proposed depreciation rates are reasonable and should be approved by the Commission.

Also, given changes made to the long-term plans for the nuclear generation plants, it is appropriate for the Company to decrease amounts accrued to fund the Nuclear Decommissioning Trust. The costs to fund the trust are a necessary component of providing the benefits of a strong nuclear fleet to our customers, are reasonable, and should be approved by the Commission.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.