Direct Testimony and Exhibits
Lori J. Mack

Before the South Dakota Public Utilities Commission
of the State of South Dakota

In the Matter of the Application of
Black Hills Power, Inc. d/b/a Black Hills Energy

for Authority to Increase Rates for Electric Service in South Dakota

Docket No. EL26-_____

February 19, 2026

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EXHIBITS

Exhibit LJM-1	Lead-Lag Study
Exhibit LJM-2	BHSC 2018 Depreciation Study

TABLE OF ABBREVIATIONS AND ACRONYMS

ADIT	Accumulated Deferred Income Tax
AIP	Annual Incentive Pay
AR15	Vintage Year Accounting under Accounting Release Number 15
BHC	Black Hills Corporation
Black Hills Power	Black Hills Power, Inc. d/b/a Black Hills Energy
BHSC	Black Hills Service Company, LLC
CAM	BHSC Cost Allocation Manual
CIS+	Customer Information System
CMA	Certified Management Accountant
Commission	South Dakota Public Utilities Commission
Company	Black Hills Power, Inc d/b/a Black Hills Energy
COSS	Cost of Service Study
CUS	Common Use System
CWC	Cash Working Capital
ECA	Energy Cost Adjustment
EDIT	Excess Deferred Income Tax
FERC	Federal Energy Regulatory Commission
FICA	Federal Insurance Contributions Act
FPPA	Fuel and Purchased Power Adjustment
FUTA	Federal Unemployment Tax Act
Gannett Fleming	Gannett Fleming Valuation and Rate Consultants, LLC
GDPM	Generation Dispatch & Power Marketing
IRP	Integrated Resource Plan
JCOSS	Jurisdictional Cost of Service Study
Lag	When a service is rendered and when revenues for that service are received
Lead	When goods or services are obtained or used and when payments for those goods or services are made

LTIP	Long-Term Incentive Plan
O&M	Operations & Maintenance
PMOI	Power Marketing Operating Income
Pro Forma Period	Twelve (12) months beginning on October 1, 2025, and ending September 30, 2026
ROE	Return on Equity
STAR	Spare Turbine Adjustment Rider
STIP	Short-Term Incentive Plan
SUTA	State Unemployment Tax Act
Test Period	Twelve (12) months beginning on October 1, 2024, and ending September 30, 2025
TOTI	Taxes Other than Federal Income Tax
WACC	Weighted Average Cost of Capital

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lori J. Mack. My business address is 7001 Mount Rushmore Road, Rapid City, South Dakota 57702.

Q. PLEASE DESCRIBE YOUR EMPLOYMENT.

A. I am employed by Black Hills Service Company, LLC ("BHSC"), a wholly-owned subsidiary of Black Hills Corporation ("BHC"), as a Manager of Regulatory.

Q. PLEASE DESCRIBE YOUR EDUCATION AND BUSINESS BACKGROUND.

A. I hold a Bachelor of Science in Professional Accounting and Management from Northern State University, an MBA from Colorado Technical University, and a Master of Science in Accounting from Bellevue University. In 2024, I earned the Certified Management Accountant ("CMA") designation.

My professional career began in retail, where I gained extensive experience in both front and back-office operations. I progressed through roles of increasing responsibility, ultimately joining the management team. In this capacity, I oversaw front and back-office operations, safety, and theft reduction initiatives, audited stores across a three-state region, and trained managers in best practices.

In 2015, I transitioned to BHSC as an Accountant in the Property Accounting department. My responsibilities included the creation, audit, and closure of capital work orders. I took on additional duties, such as reviewing team members' work and leading consolidation projects, which led to my promotion to Senior Accountant in 2018.

By 2021, I advanced to the role of Manager within the Property Accounting department, where I supervised a team of property accountants for the gas companies and

BHSC. In 2023, I assumed my current position as Regulatory Manager for the Revenue Requirements and Reporting team. In this role, I oversee a team of analysts responsible for preparing annual reports, normalized earnings reports, Federal Energy Regulatory Commission ("FERC") formula rate filings, and revenue requirement studies to support various rate base filings across multiple states.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION.

A. I am responsible for managing the Revenue Requirements Team which provides various financial analyses in support of BHC's utility subsidiaries and provides support for revenue requirement calculations in multiple states and jurisdictions as well as state and FERC annual reporting.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of Black Hills Power, Inc. d/b/a Black Hills Energy ("Black Hills Power").

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide support for the Cost of Service Study ("COSS") for Black Hills Power in this proceeding. The proposed COSS, which is included in the Application, is presented by Black Hills Power in support of the revenue requested in this proceeding and is the primary focus of my direct testimony. I introduce and describe each of the statements and schedules contained within the COSS model and explain the reasoning behind the various known and measurable adjustments and other pro forma adjustments to Black Hills Power's per-book investments, expenses, and revenues and how those adjustments are reflected within the COSS. The COSS also establishes the cost basis for Black Hills Power's base rates.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibits:

Exhibit LJM – 1 – Lead-Lag Study

Exhibit LJM – 2 – 2018 BHSC Depreciation Study.

Q. ARE THERE ADDITIONAL STATEMENTS OR SCHEDULES YOU ARE SPONSORING?

A. Yes, I am sponsoring the following Statements and supporting Schedules, which are required by ARSD 20:10:13:51-96, 100, 102) These Statements and Schedules are located in Volume 1 of the Application:

A. Balance Sheet

B. Income Statement

C. Retained Earnings Statement

D. Electric Plant in Service

- D-1. Adjusted Electric Plant in Service
- D-2. Summary of Major Additions and Retirements by Function
- D-3. Accounts 101 & 106 Plant Balances by Month for the Test Period
- D-4. Summary of Major Additions and Retirements by Function 2020-2024
- D-5. Policy of Capitalizing Interest and Other Overheads During Construction
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H-12. Fleet Depreciation O&M Adjustment

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H-15. Steam Generation O&M Expense Adjustment

H-16. Wind Generation O&M Expense Adjustment

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H-18. Generation Major Maintenance Expense Adjustment

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P. Fuel Cost Adjustment Factors

R. Computation of Coal Pricing (Purchases from Affiliated Companies)

T. Removal of Transmission Recovered Under FERC Rates

T-1. Removal of Transmission Recovered Under DC Tie Stated Rates

T-2. Removal of Transmission Recovered Under FERC Formula Rates

III. COST OF SERVICE STUDY OVERVIEW

Q. PLEASE SUMMARIZE THE RESULTS OF THE COSS.

A. The COSS calculates a revenue requirement for base rate revenues of $201,527,402, which represents a revenue increase of $54,972,617 as summarized in Schedule M-1, page 1. Schedule M-1, page 2 summarizes the South Dakota jurisdictional revenue requirement of $179,805,093 for base rate revenues, which represents a revenue increase of $50,553,697. This is based on the proposed return on equity ("ROE") of 10.5%, a cost of long-term debt of 5.50%, and a capital structure of 53.21% equity, 46.79% debt, resulting in a weighted average cost of capital ("WACC") of 8.16%.

Q. WHAT IS THE PURPOSE OF A COSS?

A. A COSS, also known as a revenue requirement study, is an analysis tool used to determine the revenues required to recover costs incurred by a public utility to provide service to its customers and to provide investors with an opportunity to earn a reasonable return. The costs to be recovered include the allocated and directly charged expenses incurred to operate and maintain facilities, administrative costs to oversee operations, and capital costs necessary to service the utility's debt and to provide investors with a return. In summary, the formula is:

Revenue Requirement = E + r (RB)

Where:

E =	Expenses = O + D + T
O =	Operating expenses, including wages and salaries, administrative expenses, taxes other than income taxes, fuel costs, and various maintenance expenses
D =	Annual depreciation expenses
T =	Income taxes (state and federal)
r =	Rate of return (return on bonds, preferred stock, and common stock (equity))
RB =	Rate base = v-d
v =	(1) Plant In-Service costs plus (2) Working capital (cash working capital + materials and supplies)
d =	Accumulated depreciation, accumulated deferred income taxes and other rate base items

Operating Expense categories include operating, maintenance, administrative, general, property tax, sales tax, payroll tax, federal income tax, depreciation, and amortization. The rate base consists of net plant investment (gross plant less accumulated provision for depreciation), working capital, including cash working capital ("CWC"), accumulated deferred income taxes ("ADIT"), and net excess deferred income taxes ("EDIT"). The return on rate base is calculated using the WACC, which includes a weighting of the cost of long-term debt and equity. The WACC is multiplied by the calculated rate base to yield the total amount of required earnings. The COSS indicates the overall level of revenues necessary to earn the authorized return, which is then used in setting base rates.

The resulting calculation, the COSS, is the amount Black Hills Power needs to collect from customers to recover its costs and provide a reasonable return to investors.

Q. HOW WAS THE COSS DEVELOPED FOR THIS RATE REVIEW?

A. The COSS starts with Black Hills Power's per book, or unadjusted, financial statements for the 12 months ending September 30, 2025 ("Test Period"), as reflected on Statements A, B, and C of the COSS, prepared in accordance with the FERC Uniform System of Accounts.

The COSS then adjusts the Test Period data to include pro forma adjustments to calculate the proposed cost of service for the 12 months ending September 30, 2026 ("*Pro Forma* Period") in this proceeding. In developing a COSS, accounting adjustments are made to add or remove certain accounts and expense transactions. Regulatory adjustments are necessary to comply with rate recovery policies established through South Dakota Public Utilities Commission ("Commission") orders in prior rate proceedings, rules, and statutes. Known and measurable and other pro forma adjustments are made to reflect future conditions at the time when new rates will be effective. All adjustments discussed in my testimony were completed at the Black Hills Power total company level unless otherwise noted. Costs are then allocated to South Dakota based on the Jurisdictional Cost of Service Study ("JCOSS") as summarized in Statement N.

Table LJM-1 below shows each statement supplied within the COSS:

Table LJM-1: Cost of Service Study Statements

Cost of Service Study Statements	
Statement A	Balance Sheet
Statement B	Income Statement
Statement C	Retained Earnings Statement
Statement D	Electric Plant in Service
Statement E	Accumulated Provision for Depreciation
Statement F	Working Capital
Statement G	Cost of Capital
Statement H	Operating and Maintenance Expenses
Statement I	Operating Revenue
Statement J	Depreciation and Amortization Expense
Statement K	Computation of Federal Income Tax
Statement L	Taxes Other than Federal Income Tax (TOTI)
Statement M	Overall & South Dakota Revenue Requirement
Statement P	Derivation of Base Unit Cost
Statement R	Computation of Coal Pricing
Statement T	Removal of Transmission Recovered Under FERC Rates

Q. PLEASE EXPLAIN HOW THE STATEMENTS AND SCHEDULES INCLUDED IN THE COSS SUPPORT THE PROPOSED REVENUE REQUIREMENT.

A. Adjustments to rate base are shown in Statements D, E, F, M, and T. Expense adjustments are reflected in Statements H, J, K and L. Revenue adjustments are shown in Statement I. Starting with Statement D, the COSS statements present summary level financial information used to calculate the revenue requirement with the supporting schedules providing the details of each section.

Statements D through T within the COSS support the revenue requirement summary in Statement M. Schedule M-1 of the COSS calculates the revenue deficiency based upon inputs from the previous statements. The revenue deficiency is the amount by which the base rate revenues need to be increased to recover the costs to operate, maintain, and manage the utility while providing Black Hills Power with a reasonable opportunity to earn its authorized rate of return.

The schedules within the COSS provide detailed information and are used to support the statements throughout the COSS. For example, Statement H of the COSS summarizes a list of adjustments to the COSS. Each adjustment is referenced by a corresponding schedule and explained separately in my direct testimony. Other COSS schedules present detailed information necessary for use in the JCOSS as shown on Statement N and CCOSS.

COSS Statement M, page 3 summarizes the detailed schedules to present the information that Mr. Douglas N. Hyatt uses to calculate the JCOSS discussed in his direct testimony and shown on Statement N. The JCOSS determines the jurisdictional revenue deficiency at issue in this proceeding. The results of the jurisdictional revenue deficiency from the JCOSS are summarized on Statement M, page 2.

Q. PLEASE EXPLAIN HOW COSS ADJUSTMENTS ARE DEVELOPED AND ALLOCATED TO THE SOUTH DAKOTA JURISDICTION.

A. The COSS was calculated at the total Black Hills Power company level. As discussed in Mr. Hyatt's testimony, the COSS then used the JCOSS which allocates costs among the various jurisdictions in which Black Hills Power operates, including South Dakota, Wyoming, Montana, and the FERC. Unless otherwise noted, all adjustments discussed in my testimony are made at the total company level before being allocated to the South Dakota jurisdiction in the JCOSS.

Q. PLEASE SUMMARIZE THE REVENUE REQUIREMENT BEING REQUESTED BY BLACK HILLS POWER.

A. Table LJM-2 below summarizes the total revenue requirement and rate increase being requested in this proceeding.

Table LJM-2: Total Company and South Dakota Revenue Requirements

Description	Total Company Revenue Requirement	South Dakota Revenue Requirement
Total Adjusted Rate Base	$ 925,201,322	$ 829,722,994
Rate of Return	8.16%	8.16%
Return	**$ 75,496,428**	**$ 67,705,396**
Operations & Maintenance	86,512,365	77,498,012
Depreciation/Amortization	65,177,339	58,110,236
Taxes Other Than Income	9,336,168	8,152,855
FIT - Existing Rates	(11,450,236)	(10,515,299)
Other Operating Revenue	(35,088,911)	(31,762,383)
Total Cost of Service	**$ 189,983,152**	**$ 169,188,817**
Revenue Under Existing Rates	146,554,785	129,251,396
Increase/(Decrease) Before Taxes	**$ 43,428,368**	**$ 39,937,421**
Combined Tax Rate	21.00%	21.00%
Revenue Deficiency / (Excess) After Tax Gross up	**$ 54,972,617**	**$ 50,553,697**
Total Revenue Requirement after Tax Gross up	**$ 201,527,402**	**$ 179,805,093**

IV. RATE BASE

Q. PLEASE DESCRIBE THE RATE BASE USED IN THE COSS.

A. Rate base is the value of invested capital, including all items used to provide utility service. Rate base represents the investor-financed plant facilities and other investments required in providing utility service to customers. A regulated utility is allowed and should have a reasonable opportunity to earn a fair rate of return on its investment in rate base. As summarized on Statement M of the COSS, rate base includes Plant in Service, Accumulated Depreciation, Working Capital, and Other Rate Base Items which include ADIT, Customer Advances, Customer Deposits, and Regulatory Assets and Liabilities.

A. Rate Base Components

Q. PLEASE EXPLAIN GENERALLY HOW RATE BASE IS CALCULATED IN A COSS.

A. Rate base represents the net investment by a utility necessary to operate the business and serve customers. Rate base is the value of invested capital, including all items used to provide utility service to customers, upon which Black Hills Power is allowed an opportunity to earn a reasonable rate of return. Rate base is made up of two general components. Costs related to property, plant, and equipment make up the primary component, and the other component is the investment required to pay bills and meet financial obligations necessary to operate the business, which is referred to as Working Capital. The total investment is determined by summing the items listed above.

1. Property, Plant, and Equipment

The primary components of rate base are the costs related to property, plant, and equipment, which includes the initial investment such as Gross Plant in Service, but also any related offset that Black Hills Power has received. Offsets to the rate base cost component include Accumulated Depreciation, ADIT, Customer Deposits, and Contributions in Aid of Construction. Total Electric Plant in Service also contains the allocated Other Utility Plant from BHSC as well as the Plant Acquisition Adjustment for Wyodak power plant held in FERC Account 114.

2. Working Capital

The other component used in calculating rate base is the investment necessary for a company to pay its bills and meet the financial obligations necessary to operate the business. This component is referred to as working capital.

The working capital component of rate base is determined by summing CWC, Materials and Supplies, and Prepaid Expenses. Goodwill or acquisition adjustments are generally not included in rate base unless otherwise approved by the Commission.

Q. WHAT ITEMS ARE INCLUDED IN OTHER RATE BASE ITEMS?

A. Schedule M-2 includes Deferred Income Tax Assets, Regulatory Liabilities for EDIT, Deferred Income Tax Liabilities (categorized as Property and Other), State Tax Items, and Other Utility Plant Deferred Income Tax (the ADIT associated with Allocated plant from BHSC).

Schedule M-3 summarizes the other non-tax Regulatory Assets and Liabilities, Customer Deposits, and Customer Advances. This includes the Pension and Retiree Healthcare regulatory assets and liabilities. Also included is the regulatory liability for Power Plant Maintenance which is adjusted by ($4,458,003) for the increase in the Power Plant Major Maintenance Accrual expense adjustment described on Schedule H-18.

Q. WHAT METHOD OF CALCULATING RATE BASE IS BLACK HILLS POWER PROPOSING FOR THE COSS PRESENTED IN THIS REVIEW?

A. Black Hills Power uses a 13-month average Test Period ending on September 30, 2025, and adjusts the rate base, as permitted under the Commission's Rules and Regulations, through September 30, 2026, as the basis of its rate base calculation for the *Pro Forma* Period. The Test Period is used as the anchor of the data and uses known and measurable adjustments to calculate the ending rate base included in the *Pro Forma* Period. Allocated plant from BHSC is recorded in FERC Account 118 and is included as part of rate base as shown on Schedule D-1 lines 192 to 195. The associated allocated accumulated reserve from BHSC is recorded in FERC Account 119 as shown on Statement E, page 2, lines 192 to 195. Allocated plant and accumulated reserve are shown by the method of allocation rather than by account. Black Hills Power's rate base also includes a Plant Acquisition Adjustment relating to the acquisition of its ownership interest in the Wyodak power plant.[1]

B. Adjustments

Q. PLEASE DESCRIBE THE ADJUSTMENTS TO PLANT IN SERVICE.

A. The adjustments include:

- Pro Forma plant additions for October 2025 through September 2026;
- Pro Forma plant retirements for October 2025 through September 2026; and
- Removal of assets recovered through FERC ratemaking.

[1] The plant acquisition adjustment represents the amount by which the Company's acquisition purchase price exceeded the undepreciated original purchase price of the plant and approved in Docket No. EL95-003. The plant acquisition adjustment has been and continues to be amortized over the remaining life of the acquired plant.

- Pro Forma Plant Additions

The first adjustment to rate base is to include plant that is forecasted to go into service during the *Pro Forma* Period. The capital additions of $111,278,649 are summarized on Schedule D-1, column (e) with the gross plant additions detailed on Schedule D-10. Black Hills Power will update the COSS at the appropriate time in the proceeding to reflect the status of projects at that time.

- Pro Forma Plant Retirements

The second adjustment to rate base is to account for expected plant retirements that will occur in the *Pro Forma* Period. Atypical retirements, such as one-time operation centers or land divestitures, were removed from annual retirement amounts. The Planned Retirements adjustment is ($21,979,853) and is summarized on Schedule D-1, column (f) with the gross plant retirements detailed on Schedule D-11.

- Removal of assets recovered through FERC ratemaking

Black Hills Power has both a transmission formula rate for the Common Use System ("CUS") and a stated rate for the DC Tie which provides recovery outside of base retail rates through FERC ratemaking. The methodology in the calculation of those rates was applied to remove a portion of assets, accumulated reserve, CWC, prepaids, materials and supplies, and ADIT for the *Pro Forma* Period ending date of September 30, 2026, to account for recovery through the FERC ratemaking. The calculations for the rate base items are shown on Schedule T-1 for the DC Tie and Schedule T-2 for the Transmission Formula Rate.

Q. PLEASE EXPLAIN THE PROPOSED PLANT ADDITIONS.

A. As shown on Schedule D-10, Line 197, Black Hills Power proposes to include $111.28 million of plant additions, including allocated plant additions, that is forecasted to be placed into service before September 30, 2026. The pro forma additions are summarized in Table LJM-3 below:

Table LJM-3: 2025-2026 Pro Forma Additions[2]

Function	Amount
Generation Plant	$60.08
Distribution Plant	37.46
Transmission Plant	2.29
General & Intangible Plant	7.22
BHSC Allocated Plant	4.22
Total Dollars in Millions	**$111.28**

Mr. Mark L. Lux discusses generation projects in his Direct Testimony. Mr. Michael A. Pogany discusses major distribution and general plant projects in his Direct Testimony.

Q. DOES BLACK HILLS POWER ACCOUNT FOR NEW CUSTOMERS ASSOCIATED WITH GROWTH CAPITAL?

A. Yes. Black Hills Power has included an adjustment to its revenues for incremental growth on Statement I, page 1, column (l) to reflect the expected additional customers associated with adding growth capital in its revenue requirement. Mr. Ethan J. Fritel discusses this adjustment further in his Direct Testimony.

[2] Although transmission assets are included in both pro forma plant additions and retirements, a majority of the dollars are removed through the DC Tie and CUS calculations. There are also no major projects planned in the *Pro Forma* Period.

Q. WERE ANY ASSUMPTIONS MADE IN THE INCLUSION OF THE CAPITAL ADDITIONS TO THE DETAILED PLANT ACCOUNTS IN SCHEDULE D-10?

A. Yes, Black Hills Power allocated additions to plant FERC accounts based on a historical closure allocation of similar types of projects.

Q. IF A HISTORIC RATIO IS USED AND ESTIMATES ARE USED, ARE THE DOLLARS REPRESENTED IN THE PLANT ACCOUNTS REASONABLE?

A. The dollars in the plant accounts are reasonable. While the actual dollars recorded for these projects may fluctuate, the methods described above provide a reasonable representation of the plant that will be placed in service. As previously discussed, plant additions and retirements will be updated at the appropriate time in the proceeding to reflect the status of projects at that time.

Q. PLEASE DESCRIBE THE PRO FORMA PLANT ADDITIONS ASSOCIATED WITH THE ALLOCATED SERVICE COMPANY ASSETS?

A. The allocated Service Company asset additions of $4,224,867 represent Black Hills Power's portion of allocated capital expenditures for computer software and hardware as well as fleet expenditures. Major projects for BHSC in the *Pro Forma* Period include annual replacement of computer hardware, upgrades to supply chain software, and replacement of the vegetation management and financial reporting software applications.

Q. IS CONSTRUCTION WORK IN PROGRESS ("CWIP") INCLUDED IN RATE BASE?

A. No. Black Hills Power assumes that all CWIP will be placed in service prior to September 30, 2026, as part of the capital additions.

C. <u>Administrative Rules – Plant</u>

Q. ARE THERE SPECIFIC REQUIREMENTS REGARDING PLANT?

A. Yes. ARSC 20:10:13:54 through 20:10:13:63 require various plant information for both the Test Period and the *Pro Forma* Period.

Q. PLEASE DESCRIBE THE STATEMENT D PAGE 1 AND PAGE 2.

A. Statement D, Page 1 fulfills the requirement set forth in ARSD 20:10:13:54 which requires a summary of accounts 101, 102, 103, 105, 106, 107, and 118 for the 12 months of the Test Period including any additions and reductions. Statement D, Page 2 summarizes the pro forma adjustments made for the adjusted Test Period ending September 30, 2026.

Q. PLEASE SUMMARIZE SCHEDULE D-2.

A. Schedule D-2 contains a summary of major additions and retirements by project that occurred during the Test Period ending September 30, 2025, as required in ARSD 20:10:13:56. Miscellaneous projects under $100,000 were grouped together under each function.

Q. PLEASE EXPLAIN SCHEDULE D-3.

A. Schedule D-3 pages 1 and 2 provides the average monthly plant balances by FERC account for Test Period as required in ARSC 20:10:13:57.

Q. PLEASE DESCRIBE SCHEDULE D-4.

A. Schedule D-4 displays a summary of the plant balances by FERC account for the years 2020 through 2024 as required by ARSD 20:10:13:58.

Q. PLEASE EXPLAIN SCHEDULE D-5.

A. As required in ARSD 20:10:13:59, Schedule D-5 describes the policy of capitalizing interest and other overheads during construction.

Q. PLEASE DESCRIBE SCHEDULE D-6.

A. Schedule D-6 displays any changes to Intangible Plant over the prior five years, as set forth in ARSD 20:10:13. Black Hills Power did not have any intangible plant as of the end of the Test Period.

Q. PLEASE EXPLAIN SCHEDULE D-7.

A. Schedule D-7 provides the cost and description of any plant in service carried on Black Hills Power's books as utility plant which was not being used in rendering service as required in ARSD 20:10:13. Black Hills Power did not have any assets included in rate base that are not used and useful as of the end of the Test Period.

Q. PLEASE DESCRIBE SCHEDULE D-8.

A. Schedule D-8 provides a description of the continuing property records and includes the methods and procedures used to price retirements as required in ARSD 20:10:13:62.

Q. PLEASE EXPLAIN SCHEDULE D-9.

A. As required in ARSD 20:10:13, Schedule D-9 displays any plant acquired for which regulatory approval has not been obtained. Black Hills Power did not acquire any plant for which regulatory approval was not obtained as of the end of the Test Period.

Q. PLEASE DESCRIBE THE ADJUSTMENTS MADE TO ACCUMULATED DEPRECIATION.

A. The adjustments include:

- Add Accumulated Depreciation for Pro Forma plant additions;
- Remove Cost and Accumulated Depreciation for Pro Forma plant retirements;
- Add Accumulated Depreciation to roll-forward the September 30, 2025, balances for existing assets; and

- Removal of Accumulated Depreciation recovered through FERC ratemaking.
  - The first adjustment is an increase in Accumulated Depreciation related to the pro forma capital additions in the amount of $2,542,863 as summarized on Statement E, page 2, line 197, column (d). The accumulated depreciation associated with the capital additions is calculated using a mid-year convention using the proposed depreciation rates. The detailed calculation is shown on Statement E, page 3.
  - The second adjustment is related to pro forma capital retirements. Since assets are retired at cost, this adjustment removes the full cost of the retired assets at ($21,979,853) as well as accumulated depreciation for those assets calculated using a mid-year convention with the proposed depreciation rates for ($1,193,368) for a total adjustment of ($22,576,537) as summarized on Statement E, page 2, line 197, column (e). The detailed calculation is shown on Statement E, page 4.
  - The third adjustment is to roll forward the accumulated depreciation associated with the plant in service as of September 30, 2025, to reflect the balance as of September 30, 2026. This roll forward in the amount of $53,426,227 is summarized on Statement E, page 2, line 197, column (f). Statement E, page 5 shows the results of the calculation of the depreciation expense under the existing depreciation rates through September 30, 2026. An associated adjustment on Schedule M-2, line 47 moves the ADIT to the projected September 30, 2026, balance.

- The fourth adjustment is to remove the corresponding accumulated reserve related to the assets recovered under FERC ratemaking. The accumulated reserve amount is calculated on Schedules T-1 and T-2 and removed on Statement E page 2, columns (g) and (h).

V. <u>WORKING CAPITAL</u>

Q. WHAT IS WORKING CAPITAL?

A. Working capital is the capital necessary to operate the business and is made up of CWC, fuel stocks, materials and supplies, and prepaid expenses. The working capital components are shown on Statement F of the COSS. CWC is determined by a lead-lag study. The other items, fuel stocks, materials and supplies, and prepaid expenses, use the Test Year 13-month average balance. The final adjusted working capital total is used in the calculation of rate base.

Q. PLEASE DESCRIBE CWC.

A. CWC is the amount of investor-supplied capital required to fund the day-to-day operations of a utility after accounting for the timing differences between the occurrence of the transaction and the actual receipt of, or payment of, cash.

Q. PLEASE DESCRIBE HOW THE CWC AMOUNT WAS CALCULATED.

A. The per book and adjusted CWC amounts were determined based on the results of a Lead-Lag Study, see Exhibit LJM-1. Black Hills Power prepared both per book and adjusted CWC amounts for this rate review. The per book Test Period CWC is located on Schedule F-3, page 1, and the *Pro Forma* Period CWC is on Schedule F-3, page 2. The adjusted CWC amount is included in rate base within the COSS on Statement M, line 23.

Q. WHAT ADJUSTMENTS WERE MADE TO PREPAID EXPENSES AND MATERIALS AND SUPPLIES?

A. Fuel Stocks, Materials and Supplies, and Prepaid Expenses were adjusted to reflect the 13-month average balances for the Test Period. Using the 13-month average method represents the ongoing level of investment necessary to serve customers throughout the year. This method avoids using a snapshot of investment that could be either a peak or valley of investment based upon timing. This differs from Property, Plant, and Equipment investment because Fuel Stocks, Materials and Supplies, and Prepaid expenses are expected to be used or consumed in less than a year while Property, Plant, and Equipment are expected to have a useful life of multiple years. The following adjusted amounts are included in working capital as shown on Statement F of the COSS:

- Fuel Stocks - $6,586,671
- Materials and Supplies - $32,442,555
- Prepaid Expenses - $1,978,870

The adjusted amount includes the removal of amounts recovered through FERC ratemaking as calculated on Schedules T-1 and T-2.

Q. WHAT MATERIALS AND SUPPLIES ARE INCLUDED IN RATE BASE?

A. The inventory of materials and supplies used for construction, operation, and maintenance purposes are included in the Materials and Supplies accounts.

As required in ARSD 20:10:13:70, Schedule F-2 sets forth the monthly balances of materials and supplies for the two years immediately preceding the Test Period.

Q. HOW DOES A LEAD-LAG STUDY MEASURE THE AMOUNT OF CASH REQUIRED FOR BUSINESS OPERATIONS?

A. A lead-lag study measures the difference between: (1) when goods or services are obtained or used and when payments for those goods or services are made ("lead") and (2) when a service is rendered and when revenues for that service are received ("lag"). The applicable lead period for each major category of expense is compared to the revenue lag period. The difference between those periods, expressed in days, multiplied by the average daily operating expense, yields the amount of CWC required for a company to meet its normal business obligations.

Q. HOW ARE THE REVENUE LAG DAYS CALCULATED?

A. The revenue lag days are comprised of the Service Lag, Billing Process Lag, and the Payment Receipt Lag on customer bills, which are added together to calculate the Revenue Lag, and utilizes data from BHC's Customer Information System ("CIS+"). The Service Lag is a weighted average of the total days of the billing period divided by two. The Service Lag weighting is based on the dollar amount of the billing revenue of the bill. The Billing Process Lag is the number of days between when the meter is read and when the customer is billed and is also weighted by the dollar amount of the billing revenue. Finally, the Receipt Lag is the weighted average number of days between billing and receipt of payment. For customers that utilize budget billing,[3] the payment received is applied to the oldest balance first. All three of these factors are calculated using CIS+ data which holds the customer accounting transaction information. The

[3] Budget billing is a free, stable billing plan giving customers more predictable bills by averaging the amount they pay each month. This allows them to avoid spikes in their bill due to seasonal usage.

resulting calculation is a Revenue Lag of 36.86 days as shown in Schedule F-3, column (d).

Q. HOW WAS THE EXPENSE LEAD CALCULATED FOR THIS RATE REVIEW?

A. The expense lead days were determined by analyzing the actual data from the Per Book Test Period for the expense categories as shown on Schedule F-3, column (c). The Lead-Lag Study steps through the calculation of the expense lead. The expense lead days are the number of days between when goods or services are received (a midpoint is used when the service is received over a period, such as payroll and payroll tax expenses) and when payment is made for those goods or services. That payment date is referred to as a settlement date. The lead days are calculated by taking the settlement date less the midpoint of service to arrive at the lead days for each month in the per book Test Period. A monthly percent of total payment is calculated by dividing the amount expensed in the month by the total annual amount expensed. The weighted average lead/lag days are then calculated by multiplying the percentage of total payment in each period by the lead days in each period to arrive at a total lead day amount. The monthly lead days are summed to arrive at the total annual lead days by expense category.

All recorded costs were reviewed for the following Operating and Maintenance ("O&M") categories:

- Direct Payroll
- Coal
- Transmission Purchases
- Purchased Power
- Purchased Fuel

- Direct and Allocated Materials and Services
- Allocated Payroll
- Other O&M

The direct payroll expense lead days are the number of days between when employees provide labor/services and when employees are paid. To determine the payroll expense lead, a midpoint is calculated for each pay period. The date funds are transferred to employees is the day before each pay date. The lead days for each period is then calculated by taking the number of days between when funds are transferred and the midpoint. Finally, an average of the lead days is taken to arrive at a payroll expense lead of 14 days.

The expense lead days are the number of days between when the goods or services are received (a midpoint is used when the service is received over a period) and when payment is made. The lead days are calculated by taking settlement date minus the midpoint of service to arrive at a lead day for each month in the Per Book Test Period. As there are multiple payments made on different days throughout each service period, a weighted average lead days is calculated for each payment within each month to arrive at the total lead days per period. These weighted lead days are then totaled for each service period, and a weighted average is calculated once more by multiplying the percentage of total payment in each period by the lead days in each period to arrive at the weighted average lead days for each service period. Transmission – Direct Purchases, Purchased Power – Direct Purchases, and Purchased Fuel are all calculated using this methodology. Intercompany costs like Transmission Purchases or Purchased Power are all calculated when they are paid through intercompany settlements. Since costs come from affiliated companies, they are settled monthly via a systematic process in which each company is made whole. The Transmission – Direct Purchases lead days are 26.86. Transmission – Intercompany Purchases are 36.65 days. The calculated Direct and Intercompany Purchased Power lead days are 33.23 and 35.78 respectively. Purchased Power relating to Renewable Ready is excluded from the lead-lag study, so lead days are set at 0 to not skew the Other O&M category. The calculated Purchased Fuel expense lead days are 39.08.

The direct materials and direct services expense lead days are calculated by taking an average of the number days between when materials or services are received and when payment is made to arrive at the total lead days in each period. As there are multiple payments made on different days throughout each service period, a weighted average lead days is calculated for each payment within each month to arrive at the total lead days per period. These weighted lead days are then totaled for each service period, and a weighted average is calculated once more by multiplying the percentage of total payment in each period by the lead days in each period to arrive at the weighted average lead days for each service period. Finally, the weighted average lead days are summed to arrive at the expense lead days of 28.87 for direct materials and 30.17 for direct services.

The allocated materials, services, and payroll expense lead days are all calculated when they are paid through intercompany settlements. Since costs come from affiliated companies, they are settled monthly via a systematic process in which each company is made whole. The settlement date for each month is subtracted from the midpoint of each service period to arrive at the total number of lead days. Then the monthly expense is divided by the overall expense to calculate the allocation amount which is then multiplied by the month's lead days to arrive at that month's weighted average lead days. Finally, the weighted average lead days are totaled to arrive at the expense lead of 36.60 for allocated materials, 37.32 for allocated services, and 37.30 for allocated payroll.

The remaining Other O&M category utilized the weighted average of all other expense lead days which calculated to 31.07 lead days. The total expense lead days are a weighted average calculated by taking the sum of the total expenses per category divided by the total expenses multiplied by the expense lead per category, as shown in Schedule F-3, column (e).

All costs were also reviewed for the following Taxes Other Than Income Taxes expense categories:

- *Ad Valorem* Taxes
- Federal Insurance Contributions Act ("FICA") Taxes – Employer's
- Unemployment Taxes (Federal Unemployment Tax Act ("FUTA") and State Unemployment Tax Act ("SUTA")
- Wyoming City Franchise Taxes
- Sales Taxes
- Current Federal Income Taxes

To determine the property tax expense lead, a period midpoint is calculated. The lead days for each period are calculated by determining the number of days between the period midpoint and the payment date. Next, a weighted average lead day percent is calculated by dividing the period expense by the total annual expense. The average lead days for each period is then calculated by multiplying the weighted average lead day percent by the lead days. Finally, the average lead days are totaled to arrive at a property tax expense lead of 284.43 days.

FICA Taxes – Employer's and Unemployment Taxes (FUTA and SUTA) – both follow the Direct Payroll calculation since they are accrued in correlation with payroll payments and have a lead of 14.00 days.

The city franchise tax expense lead is calculated by first determining the weighted days outstanding for each period by dividing the period expense by the total annual expense. Next, a midpoint is determined for each period. Monthly lead days are then calculated by determining the number of days between the midpoint and the payment date. The monthly lead days are then multiplied by the weighted days outstanding for each period and totaled to determine the lead days for the monthly expense. The weighted lead days are then calculated by dividing the total monthly expense by the sum of the monthly expense. Finally, the weighted lead days for the monthly expense are totaled to arrive at a franchise tax expense lead of 51.25 days.

To calculate the sales tax expense lead, a midpoint for each period is determined. The lead days for each period are then calculated by taking the number of days between the midpoint and the payment date. Next, a percentage of the annual expense is calculated by dividing the expense in each period by the total annual expense. The weighted average lead days are then calculated by multiplying the percentage of the annual expense by the lead days. Finally, the weighted average lead days are summed to calculate the sales tax expense lead of 23.09 days.

To calculate the income tax expense lead days, a single period midpoint is determined. As there are four quarterly income tax payments made throughout the year, this midpoint is used for each payment. Next, the lead days for each payment are calculated by determining the number of days between the midpoint and the payment date. The percentage of the total annual expense for each payment, 25% (four quarterly payments), is then multiplied by the lead days for each payment to arrive at the weighted average lead days. Finally, the weighted average lead days are summed to arrive at the income tax expense lead of 36.63 days.

Q. WHAT WERE THE RESULTS OF THE LEAD-LAG STUDY?

A. When the Lead-Lag Factors are applied to the updated expense levels, it results in a negative CWC allowance and a decrease to rate base for the *Pro Forma* Period CWC of ($496,619) as shown on Schedule F-3 Page 2, Line 29, column (h). Once adjusted for the removal of CWC relating to the DC Tie and CUS, it results in a negative CWC allowance of ($1,467,959) as shown on Statement F, line 5, column (h).

The individual results of the Lead and Lag for each category are summarized in Table LJM-4 below:

Table LJM-4 – Lead/Lag Study

Account Description	Revenue Lag (Days)	Expense Lead (Days)
Operations & Maintenance Expense		
Direct Payroll	36.86	14.00
Coal	36.86	5.79
Transmission – Direct Purchase	36.86	26.86
Transmission - Intercompany	36.86	36.65
Purchased Power – Direct Purchases	36.86	33.23
Purchased Power - Intercompany	36.86	35.78
Purchased Power – Renewable Ready	0	0
Purchased Fuel	36.86	39.08
O&M Expenses – Direct Materials	36.86	28.87
O&M Expenses – Direct Services	36.86	30.17
O&M Expenses – Allocated Materials	36.86	36.60
O&M Expenses – Allocated Services	36.86	37.32
O&M Expenses – Allocated Payroll	36.86	37.30
Other O&M	36.86	31.07
Ad Valorem Taxes	36.86	284.43
FICA Taxes - Employer's	36.86	14.00
Unemployment Taxes (FUTA & SUTA)	36.86	14.00
Wyoming City Franchise Taxes	36.86	51.25
Sales Taxes	36.86	23.09
Current Income Taxes-Federal and State	36.86	36.63

Q. WHAT IS THE TOTAL RATE BASE VALUE PROPOSED BY BLACK HILLS POWER?

A. In summary, Black Hills Power proposes a total rate base of $925,201,322 as shown in the COSS on Statement M, page 1, line 26, column (h). This consists of the following items:

- Plant in Service - $1,587,000,755 as shown on Statement D, page 2, line 16, column (j);

- Accumulated Depreciation – ($534,920,354) as shown on Statement E, page 2, line 197, column (i);
- Working Capital – $39,540,136 as shown on Statement F, line 6, column (h); and
- Other Rate Base Items – ($166,419,214) as shown on Schedule M-2, line 56, column (h) and Schedule M-3, line 23, column (h).

VI. COST OF CAPITAL

Q. WHAT IS THE PROPOSED CAPITAL STRUCTURE AND RATE OF RETURN INCLUDED IN THE COSS?

A. The proposed capital structure as presented on Statement G, page 1 and included in the COSS calculation is 53.21% equity and 46.79% debt, as discussed in the Direct Testimony of Mr. Thomas D. Stevens. Based on the proposed return on equity of 10.5%, as discussed in the Direct Testimony of Mr. McKenzie, and the cost of long-term debt of 5.50%, as discussed in the Direct Testimony of Mr. Stevens, the resulting WACC requested by Black Hills Power is 8.16%, as shown below in Table LJM-5.

Table LJM-5 – Requested WACC

	Capital Structure	Cost of Debt/Equity	Weighted Cost
Long-Term Debt	46.79%	5.50%	2.57%
Common Equity	53.21%	10.50%	5.59%
Rate of Return	**100.00%**		**8.16%**

Q. PLEASE SUMMARIZE STATEMENT G, PAGE 2.

A. Statement G, page 2 presents the weighted average cost of debt capital for each class and series of long-term debt outstanding for the balance sheet ending September 30, 2025, as required by ARSD 20:10:13.

Q. PLEASE DESCRIBE STATEMENT G, PAGE 3.

A. Statement G, page 3 fulfills the requirement set forth in ARSD 20:10:13:74 which requires Black Hills Power to show the weighted average cost of preferred stock capital for each class and series of preferred stock outstanding for the balance sheet ending September 30, 2025. Black Hills Power had no preferred stock during the Test Period.

Q. WHAT IS THE PURPOSE OF STATEMENT G, PAGE 4?

A. Statement G, page 4 shows the sale of common stock during the five-year period preceding end of the September 30, 2025, Test Period and fulfills the requirement set forth in ARSD 20:10:13. Black Hills Power had no common stock for the five-year period preceding the end of the Test Period.

Q. PLEASE EXPLAIN SCHEDULE G-1.

A. Schedule G-1 details any stock dividends, stock splits, or changes in par or stated value during the five-year period preceding the end of the September 30, 2025, Test Period. It fulfills the requirement set forth in ARSD 20:10:13:76. Black Hills Power had no stock dividends, stock splits, or changes in par or stated value during the requested time period.

Q. PLEASE EXPLAIN THE PURPOSE OF SCHEDULE G-2.

A. Schedule G-2 fulfills the requirement set forth in ARSD 20:10:13 and details information on common stock for the five calendar years preceding the end of the September 30, 2025, Test Period as well as the 12 months of the Test Period.

Q. PLEASE DESCRIBE SCHEDULE G-3.

A. Schedule G-3 is required under ARSD 20:10:13:78 and provides details on any bonds or preferred stock that were reacquired by the utility in the 18 months prior to filing. Black

Hills Power did not reacquire any bonds or preferred stock during the required time period.

Q. PLEASE SUMMARIZE SCHEDULE G-4.

A. Per ARSD 20:10:13:79, Schedule G-4 shows the earnings per share of common stock which the claimed rate of return would yield and the basis upon which it is determined.

VII. OPERATING EXPENSES

Q. WHAT ARE OPERATING EXPENSES?

A. Operating expenses are costs associated with the operation, maintenance, and administration of Black Hills Power's utility business on a day-to-day basis to provide service to customers. In the development of the revenue requirement, operating costs are passed on to customers dollar-for-dollar. In other words, Black Hills Power does not earn a return on these expenses but receives a pass-through cost recovery.

Q. PLEASE EXPLAIN HOW THE STATEMENTS AND SCHEDULES CONTAINED IN THE COSS SUPPORT THE EXPENSE AMOUNTS PRESENTED IN THIS CASE.

A. Statement B shows the income statement for the 12 months ending September 30, 2025. Statement H details the per book O&M expenses provided on Statement B by FERC account and provides a summary of adjustments and adjusted totals. Depreciation and amortization expense is detailed on Statement J, which includes the pro forma adjustments and calculates adjusted depreciation and amortization expense based on plant balances for the *Pro Forma* Period ending September 30, 2026. Taxes Other Than Income are detailed on Statement L, which shows the pro forma adjustments and calculates adjusted taxes other than income total amounts. Income tax calculations are shown on Statement K, which details the income tax expense, permanent and temporary differences, and total deferred income tax expense. All the adjusted total amounts are included in the calculation of the additional revenue required on Statement M.

A. Operation & Maintenance Adjustments

Q. PLEASE LIST THE ADJUSTMENTS MADE TO THE PER BOOK O&M EXPENSES.

A. See Table LJM-6 below for the listing of the O&M adjustments:

Table LJM-6 – O&M Adjustments

O&M Adjustments	
Schedule H-1	Adjustments to Operating and Maintenance Expense (Labor and Non-Labor)
Schedule H-2	Purchase Power and Fuel Expense Adjustment
Schedule H-3	Listed Expense Accounts
Schedule H-4	Intercompany Allocated Charges From BHSC Expense Adjustment
Schedule H-5	Adjustment for Annualization of Direct Employee Expenses
Schedule H-6	Out of Period/Non-Recurring Adjustments
Schedule H-7	Removal of Advertising Expense
Schedule H-8	Removal of Dues and Contributions Expense
Schedule H-9	Bad Debt Adjustment
Schedule H-10	Pension and Retiree Healthcare Expense Adjustment
Schedule H-11	Rate Case Expense Adjustment
Schedule H-12	Fleet Depreciation O&M Adjustment
Schedule H-13	Regulatory Commission Expense Adjustment
Schedule H-14	FERC Fees Expense Adjustment
Schedule H-15	Steam Generation O&M Expense Adjustment
Schedule H-16	Wind Generation O&M Expense Adjustment
Schedule H-17	Other Generation O&M Expense Adjustment
Schedule H-18	Generation Major Maintenance Expense Adjustment
Schedule H-19	Gillette Energy Complex Shared Facilities Adjustment
Schedule H-20	Gillette Energy Complex Common Allocations Adjustment
Schedule H-21	Removal of Spare Turbine Expenses
Schedule H-22	Generation Dispatch & Power Marketing (GDPM) Expense Adjustment
Schedule H-23	Vegetation Management Expense Adjustment
Schedule H-24	Demand Side Management Expense Adjustment
Schedule H-25	Economic Development Expense Adjustment
Schedule H-26	Third Party Line Locator Expense Adjustment

Schedule H-27	Customer Education Expense Adjustment
Schedule H-28	Removal of CUS and DC Tie O&M Expenses

Q. PLEASE DESCRIBE SCHEDULE H-1 ADJUSTMENTS TO OPERATING AND MAINTENANCE EXPENSES?

A. Schedule H-1 summarizes the Test Period O&M expenses as well as the pro forma adjustments and the adjusted amounts. The amounts are categorized by functional class and by labor and non-labor amounts as required in ARSC 20:10:13.

Q. PLEASE EXPLAIN THE PURCHASED POWER AND FUEL EXPENSE ADJUSTMENT ON SCHEDULE H-2.

A. Schedule H-2 identifies the energy resources to be used to serve customer loads through purchase power agreements, market purchases, natural gas purchases, and transmission expenses which are recovered through the Electric Cost Adjustment ("ECA"). This results in a reduction to the pro forma expenses of ($108,673,765). The revenues associated with these costs are also removed in Schedule I-2. This schedule also includes information about energy purchases which fulfills the requirements set forth in ARSD 20:10:13:82.

Q. PLEASE DESCRIBE SCHEDULE H-3 LISTED EXPENSE ACCOUNTS.

A. Schedule H-3 includes details for designated accounts for the 12 months of the Test Period and for claimed adjustments as required under ARSD 20:10:13.

Q. PLEASE EXPLAIN THE ADJUSTMENTS RELATING TO INTERCOMPANY CHARGES FROM BHSC ON SCHEDULE H-4.

A. Schedule H-4 shows BHSC allocated charges under the BHSC Cost Allocation Manual ("CAM") for the Test Period and associated pro forma adjustments. These adjustments reflect updated BHSC costs and allocations of expenses throughout the Test Period and adjust for known and measurable changes. Black Hills Power receives costs through both direct and indirect allocations under the terms of the CAM. The following adjustments are included within Schedule H-4:

- An out-of-period adjustment removes insurance costs that were inadvertently attributed to Black Hills Power instead of the appropriate affiliate. This is a reduction of ($94,944).
- Labor related adjustments are summarized below:
  - Increased headcount due to hiring for vacant positions. This results in an increase of $3,496,431 that is included in the total labor adjustment.
  - Annualization of labor expense after the 2026 merit increases, based upon October 1, 2025, pay rates to reflect average merit increases of 3.5% that will occur in February 2026. Mr. Kris Pontious explains the merit increase and overall compensation philosophy in his Direct Testimony. Black Hills Power's share of the resultant operating costs for annual merit increases to BHSC staff compensation is $840,066.
  - Adjusting the Annual Incentive Pay ("AIP") and Short-Term Incentive Plan ("STIP") payout to 100% of target. Although incentives paid each year can be variable, adjusting the 2025 incentive paid in 2026 to 100% of target is representative of future costs. This results in an increase of $363,175 that is included in the total labor adjustment.
  - Removal of labor costs relating to Generation Dispatch & Power Marketing, which is shown on Schedule H-22. This results in a decrease of ($246,104).

The net of the labor adjustments is an increase of $4,453,569.

- Insurance premiums are adjusted to reflect the new contract rates for operations insurance, property insurance and general business insurance. Black Hills Power will receive premium renewals in July 2026 and will update the COSS to reflect the new premiums at an appropriate time in the proceeding. This adjustment increases expenses by $2,454,349, based upon current invoices. As described in the Direct Testimony of Mr. Jerrad S. Hammer, Black Hills Power is proposing to defer insurance costs above or below the base amounts in a deferred account.
- Pooled medical benefit costs are adjusted to reflect the 2026 level of expense which increases expenses by $581,936 and is reflective of ongoing premium increases.
- Updated CAM allocation factors were applied to the Test Period expenses. The Test Period costs indirectly allocated to Black Hills Power were based on the allocation factors as of September 30, 2023, for October through December 2024 costs and as of September 30, 2024, for January through September 2025 costs. As further discussed by Mr. Jason S. Keil, BHC performs an annual review and update of allocation factors as of September 30 each year to go into effect on January 1 of the following year. Based on BHC's practice of updating the allocation factors, new factors and resulting allocation percentages were calculated as of September 30, 2026, to be used beginning January 1, 2027. The updated allocation rates were applied to the total pro forma pool of indirect costs which resulted in an increase of costs to

Black Hills Power. This application was completed so that the CAM calculations applied on the date that new rates for Black Hills Power effectively match the shared service expenses in the underlying revenue requirements. The net effect of the changes increased the shared service costs chargeable to Black Hills Power by $1,714,360.

The sum of the adjustments as shown on Schedule H-4, line 147, column (i) is $9,109,270.

Q. WHAT ADJUSTMENT DID BLACK HILLS POWER MAKE FOR THE ANNUALIZATION OF DIRECT EMPLOYEES ON SCHEDULE H-5?

A. The adjustment of $2,800,585[4] on Schedule H-5, line 149, column (d) represents the adjustment to annualize the wages of direct Black Hills Power employees using payroll data as of September 30, 2025, which is representative of employee headcount in the *Pro Forma* Period. As of that date, there were 200 full time employees and 8 open positions, for a total of 208 employees at the end of the *Pro Forma* Period. The pro forma adjusted amounts incorporate an average merit increases of 3.5% which will be implemented in February 2026 for non-union employees, contracted step increases for bargaining union employees, AIP costs representing 100% of targeted payout, benefits, overtime, call-out, and standby pay. The payroll tax adjustment related to wages and salaries is included in Statement L.

[4] The adjustment for the annualization of direct employees excludes the adjustment of $102,442 in account 501 which is recovered through the ECA and is included in the adjustment on Statement P, page 1, line 2.

Q. PLEASE EXPLAIN ANY OUT OF PERIOD OR NON-RECURRING ADJUSTMENTS SHOWN ON SCHEDULE H-6.

A. Schedule H-6 adjusts the per book data for any out of period or atypical expenses made during the Test Period. This results in a reduction of ($298,906) as shown on Schedule H-6, line 9, column (d).

Q. PLEASE DESCRIBE THE ADJUSTMENT THAT BLACK HILLS POWER MADE TO ADVERTISING EXPENSE ON SCHEDULE H-7.

A. Schedule H-7 eliminates all costs associated with brand and image advertisements and sponsorship of community organizations. The advertising expenses included in the COSS are related to hiring, promoting electrical utility safety (i.e. Call 811 campaigns), and educating consumers on the utility's income-based programs, special rates, pilot programs, energy conservation, significant weather events, and energy efficiency. This adjustment removes ($463,179) as shown on Schedule H-7, line 10, column (d).

Q. PLEASE EXPLAIN THE DUES AND CONTRIBUTIONS REMOVED ON SCHEDULE H-8.

A. Schedule H-8 removes the costs of dues and contributions associated with economic development associations and other similar contributions not recoverable from customers. The adjustment removes ($10,055) as shown on Schedule H-8, line 12, column (d).

Q. PLEASE DESCRIBE BLACK HILLS POWER'S ADJUSTMENT TO BAD DEBT EXPENSE ON SCHEDULE H-9.

A. Bad debt expense is calculated as a percentage of overall revenue. The adjustment reflects the impact of higher bad debt expense because of the higher revenues resulting from this rate review and adjusts the bad debt expense to increase at the same rate proportional to revenues. Black Hills Power calculated an average effective uncollectible rate of 0.2239 %. This is accomplished by calculating the three-year average net write-offs for years ending September 30, 2023, 2024, and 2025. The average net write-offs are then divided by the average total billed revenue over that same time frame. To determine the adjustment, the average effective uncollectible rate was multiplied by the adjusted Revenue Requirement shown on Statement M, line 2, column (h) plus the revenues recovered outside of base rates. This calculated net write-off amount was then compared to the per-book bad debt expense amount in FERC Account 904. The result is an adjustment which increases expenses in the amount of $90,169 as shown in Schedule H-9, line 23.

Q. PLEASE EXPLAIN THE ADJUSTMENTS TO PENSION AND RETIREE HEALTHCARE EXPENSES ON SCHEDULE H-10.

A. Schedule H-10 adjusts the Test Period expenses for pension and retiree healthcare costs to the actuarially forecasted expenses ending September 30, 2026, as discussed in the Direct Testimony of Mr. Stevens. An adjustment was made to reduce Retiree Healthcare expense in the amount of ($39,277), as shown on Schedule H-10, line 4, column (d). Pension expense adjustments result in a decrease to operating expense in the amount of ($35,817), as shown on Schedule H-10, line 9, column (d). The net of these adjustments is a decrease to operating expense in the amount of ($75,093), as shown on Schedule H-10, line 11, column (d).

Q. WHAT ADJUSTMENT DID BLACK HILLS POWER MAKE FOR RATE CASE EXPENSES ON SCHEDULE H-11?

A. Black Hills Power is requesting to recover its actual rate case expenses incurred from this proceeding and related expenses incurred in conjunction with the previously conducted Integrated Resource Plan ("IRP") type analyses. Black Hills Power estimates it will incur $800,000 of Commission fees, consulting, noticing, and other external expenses related to this proceeding. Additionally, Black Hills Power is requesting recovery of $975,906 for IRP type analyses expenses incurred in 2018, 2021, and 2024. These costs are discussed in more detail in Mr. Hammer's testimony.

Q. HOW DOES BLACK HILLS POWER PROPOSE TO RECOVER THESE EXPENSES?

A. Black Hills Power proposes to recover these expenses over a five-year amortization period. Using the proposed amortization period and the current estimate of rate case expenses results in an adjustment of $355,181 as shown in Schedule H-11, line 31. Black Hills Power will update its estimate of current rate case expenses at an appropriate time in the procedural schedule.

Q. HOW DOES BLACK HILLS POWER ACCOUNT FOR A CHANGE IN FLEET DEPRECIATION RATES ON SCHEDULE H-12?

A. Depreciation expense associated with fleet investment is not recorded in the depreciation accounts but rather is recorded in a clearing account allocated through the fleet loading process. This process allocates fleet costs, including depreciation expense, based upon the actual use of the vehicles. Utilizing the proposed depreciation rates from this proceeding, depreciation expense was adjusted to annualize the expense and takes into consideration that only a portion of the actual expense is reflected in per-book O&M expenses. The remaining depreciation expense is coded to either capital projects or to non-utility expenses based on the use of the vehicles. The adjustment for fleet depreciation expense is allocated to accounts in the same ratio as the fleet loadings. This method reflects the annualized depreciation expense as though it had been recorded through the fleet loadings process. The O&M adjustment for fleet depreciation is an increase of $523,392 as shown in Schedule H-12, line 147, column (d).

Q. PLEASE DESCRIBE THE REGULATORY COMMISSION EXPENSE ADJUSTMENT ON SCHEDULE H-13.

A. Schedule H-13 details the increase in O&M expense related to the South Dakota Commission fees incurred. The incremental increase in revenue is first allocated between South Dakota and Wyoming. Then the incremental increase in allocated South Dakota revenue is multiplied by the Mill Levy Rate of 0.1500%, as ordered in May 2025, to arrive at an incremental adjustment of $72,723, as shown on Schedule H-13, line 10. The incremental revenue increase for Wyoming is multiplied by the current apportionment percentage of 0.3654%, as invoiced in August 2025, to calculate an adjustment of $17,242, as shown on Schedule H-13, line 20. The total regulatory commission expense adjustment as shown on Schedule H-13, line 24 is $89,965. However, only the South Dakota Adjusted Gross Receipts expense was included in the South Dakota JCOSS.

Q. PLEASE EXPLAIN WHY BLACK HILLS POWER REMOVED FERC FEES ON SCHEDULE H-14?

A. FERC fees are removed from the per book expenses since they are recovered through FERC ratemaking. This results in a reduction of ($726,933) as shown on Schedule H-14, line 3.

Q. PLEASE DESCRIBE THE STEAM GENERATION O&M EXPENSE ADJUSTMENT ON SCHEDULE H-15.

A. Schedule H-15 includes an adjustment to expenses relating to Black Hills Power's steam generating facilities – Neil Simpson II, Wygen III, and Wyodak – to reflect changes to pro forma normal operating expenses. It does not include the accrual for major maintenance expenses. The adjustment is reflective of Black Hills Power's 52% ownership share of Wygen II and 20% ownership share of Wyodak. The total pro forma adjustment is a reduction of ($738,631) as shown on Schedule H-17, line 67, column (e).

Q. WHAT ADJUSTMENT DID BLACK HILLS POWER MAKE TO THE WIND GENERATION O&M EXPENSE ON SCHEDULE H-16?

A. This is an adjustment to normalize operating expenses for Corriedale excluding any adjustments for major maintenance expenses. This adjustment is reflective of Black Hills Power's 62% ownership share of Corriedale. The total pro forma adjustment is $293,307 as shown on Schedule H-18, line 6, column (d).

Q. PLEASE EXPLAIN THE OTHER GENERATION O&M EXPENSE ADJUSTMENT ON SCHEDULE H-17.

A. Schedule H-17 includes an adjustment to expenses relating to Black Hills Power's other generating facilities, including Ben French Units, Cheyenne Prairie, Lange I CT, and Neil

Simpson CT, to reflect changes to pro forma normal operating expenses. It does not include the accrual for major maintenance expenses. The adjustment is reflective of Black Hills Power's 58% ownership share of Cheyenne Prairie. The total pro forma adjustment is a reduction of ($969,961) as shown on Schedule H-17, line 74, column (e).

Q. PLEASE DESCRIBE THE GENERATION MAJOR MAINTENANCE EXPENSE ADJUSTMENT ON SCHEDULE H-18.

A. Schedule H-18 details the adjustments to the major maintenance expense to align it with the average major maintenance expense for each of Black Hills Power's generating facilities. Major maintenance expenses are first reduced by ($2,345,130) to remove extraordinary costs as shown on line 5. Then the major maintenance accrual is increased by $4,458,003 as shown on line 11 to account for planned major maintenance which is held in the major maintenance regulatory asset. The total pro forma adjustment shown on Schedule H-20, line 17, column (d) is $2,112,874.

Q. WHAT ADJUSTMENT DID BLACK HILLS POWER MAKE FOR THE GILLETTE ENERGY COMPLEX - SHARED FACILITIES ON SCHEDULE H-19?

A. The adjustment on Schedule H-19 reflects the adjustment to expenses for Black Hills Power's share of the allocated costs for the use of the shared facilities at the Gillette Energy Complex. The pool net capacity and allocator applicable to Black Hills Power are detailed on lines 29-36. The adjustment to the rent expense for Black Hills Power for the *Pro Forma* Period is $288,060 as shown on Schedule H-19, line 3, column (f).

Q. WHAT ADJUSTMENT DID BLACK HILLS POWER MAKE FOR THE GILLETTE ENERGY COMPLEX – COMMON ALLOCATIONS ON SCHEDULE H-20?

A. The total pro forma adjustment on Schedule H-20, line 125, column (i) is a reduction of ($93,782) and consists of the five adjustments detailed below.

Schedule H-20, column (d) is the expense allocation adjustment for the Gillette Energy Complex common steam facilities. The common steam facilities expenses are allocated based on each owner's generating capacity at the complex. Black Hills Power is responsible for the capacity associated with Neil Simpson II and its 52% ownership share of Wygen III. Expenses are adjusted to reflect changes that will occur in the *Pro Forma* Period and result in a decrease to operating expenses of ($41,000) as shown on line 125.

Schedule H-20, column (e) is the expense allocation adjustment for the common gas facilities for the same categories as listed above, which is also based on the capacity for Neil Simpson CT, and results in an increase of $28,251 in operating expenses as shown on line 125.

Schedule H-20, column (f) adjusts the common A&G costs related to the Gillette Energy Complex which are allocated based on each owner's generating capacity and results in a decrease of ($32,465) in operating expenses as shown on line 125.

Schedule H-20, column (g) details the adjustment related to the north allocation of the Gillette Energy Complex for the same categories as listed above, which are also based on capacity and result in a decrease of ($73,967) in operating expenses as shown on line 125. The north allocation at the Gillette Energy Complex allocates common costs to

Black Hills Power based on its 52% ownership share of Wygen III which is jointly owned with the City of Gillette and Montana Dakota Utilities and Wygen II which is owned by Cheyenne Light, Fuel, and Power.

Schedule H-20, column (h) details the adjustment related to the south allocation of the Gillette Energy Complex for the same categories as listed above, which are also based on capacity and result in an increase of $25,399 in operating expenses as shown on line 125. The south allocation at the Gillette Energy Complex allocates common costs to the Black Hills Power owned Neil Simpson II and Black Hills Wyoming, Inc. owned Wygen I.

The total adjustment relating to the Gillette Energy Complex Common Allocations is a reduction of ($93,782) to operating expenses as shown on line 125, column (i).

Q. PLEASE EXPLAIN THE REMOVAL OF SPARE TURBINE EXPENSES ON SCHEDULE H-21.

A. Schedule H-21 is an adjustment to remove expenses relating to the spare turbine assets which Black Hills Power is proposing to recover outside of base rates as explained by Mr. Keil in his testimony. This recovery would align with the corresponding spare turbine rent adjustment on Schedule I-10. Expenses of ($1,785,952) are removed on Schedule H-21, line 3, column (d).

Q. PLEASE SUMMARIZE THE ADJUSTMENT ON SCHEDULE H-22 FOR GENERATION DISPATCH & POWER MARKETING ("GDPM").

A. Total generation and dispatch scheduling costs for the Test Period are compared to the costs for the *Pro Forma* Period which adjusts the total costs for the GDPM department for increases in labor costs. Since 50% of the labor costs related to power marketing are included in the Power Marketing Operating Income ("PMOI") calculation for the Fuel and Purchased Power Adjustment ("FPPA")[5], they are removed from the pro forma adjustment.

GDPM costs are allocated to Black Hills Power and its affiliates based on the weighted average capacity of the generating resources dispatched by GDPM. In addition to the adjustment for pro forma costs, Schedule H-22 also adjusts the allocated costs for changes in dispatched resources during the *Pro Forma* Period. This results in a total increase of $81,701 in operating expenses as shown on Schedule H-22, line 105, column (d).

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR VEGETATION MANAGEMENT EXPENSE ON SCHEDULE H-23.

A. Schedule H-23 shows the adjustment to the per book vegetation management expense to adjust for a known and measurable third-party contract increase which will occur beginning in 2026. This results in an adjustment of $216,781, as shown on Schedule H-23, line 6, column (d).

Q. PLEASE EXPLAIN THE DEMAND SIDE MANAGEMENT EXPENSE ADJUSTMENT ON SCHEDULE H-24.

A. Schedule H-24 adjusts the per book demand side management program to a total of $500,000. This results in an increase of $347,650, as shown on Schedule H-24, line 3, column (d). This energy efficiency program is discussed in more detail in the Mr. Keil's testimony.

[5] South Dakota Tariff Section No. 3C, Third Revised Sheet No. 13, Page 2 of 4.

Q. WHAT ADJUSTMENT DID BLACK HILLS POWER MAKE FOR ECONOMIC DEVELOPMENT EXPENSES ON SCHEDULE H-25?

A. In Docket No. EL14-026, the Commission approved for economic development expenses up to $100,000 to be shared equally by shareholders ($50,000) and customers ($50,000). Black Hills Power is requesting to increase the total customer portion of economic development to $100,000. This results in an increase of $4,127 in operating expenses as shown on Schedule H-25, line 5, column (d). This adjustment is discussed further in the direct testimony of Mr. Keil.

Q. PLEASE EXPLAIN THE THIRD-PARTY LINE LOCATOR EXPENSE ADJUSTMENT ON SCHEDULE H-26.

A. Schedule H-26 adjusts the per book Test Period expenses relating to third party line locates for an increase in contractor costs. This will increase the operating expense by $394,097 as shown on Schedule H-26, line 3, column (d).

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR CUSTOMER EDUCATION EXPENSE ON SCHEDULE H-27.

A. Schedule H-27 includes an increase of $125,000 to account 908 as shown on line 3, column (d) which relates to the implementation of a customer education program which is discussed further in the direct testimony of Mr. Keil.

Q. WHY DID BLACK HILLS POWER REMOVE EXPENSES RELATED TO THE CUS AND DC TIE ON SCHEDULE H-28?

A. A portion of O&M expenses allocated to the CUS transmission formula rate and the DC Tie stated rate are removed from the overall O&M costs because they are recovered through the FERC ratemaking process. Removing FERC recovered items from base rates ensures that customers pay only for retail services and avoids double recovery by Black Hills Power. A total reduction of ($11,449,815) in operating expenses is shown on Schedule H-28, line 147, column (j).

VIII. DEPRECIATION EXPENSE

Q. WAS A DEPRECIATION STUDY COMPLETED AS PART OF THIS RATE REVIEW?

A. Yes, a depreciation study was completed for Black Hills Power as part of this rate review. That study is presented as Exhibit JJS-2 by Mr. John J. Spanos from Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") along with his direct testimony in this proceeding and represents the depreciation rates calculated using plant and accumulated depreciation balances as of June 30, 2025. Black Hills Power also utilizes BHSC's depreciation study as of October 31, 2018 (Exhibit LJM-2), in this proceeding as the basis for calculating depreciation expense for allocated BHSC plant.

Q. IS BLACK HILLS POWER PROPOSING ANY CHANGES IN ITS DEPRECIATION ACCOUNTING IN THIS PROCEEDING?

A. Yes. Gannett Fleming recommends re-aligning the accumulated depreciation reserve balances for utility accounts utilizing Vintage Year Accounting under Accounting Release Number 15 ("AR 15"). This realignment of accumulated depreciation reserve balances will reflect the appropriate Accumulated Depreciation balances going forward for depreciation groups that were calculated in the study prepared by Mr. Spanos. The realignment creates a debit balance of unrecovered reserve, to be amortized separately from the depreciation study. Black Hills Power proposes to amortize its unrecovered reserve balance over five (5) years. This annual amortization amount is $677,096 and is shown on Statement J, line 7.

BHSC utilizes the same process for its unrecovered reserve balance created as a result of the 2018 depreciation study. Those unrecovered reserve balances are currently being amortized over ten (10) years which will be complete in February 2030. The allocated portion of this amortization expense is $584,852 annually and is shown on Statement J, line 16.

Q. PLEASE EXPLAIN VINTAGE YEAR ACCOUNTING UNDER AR 15?

A. Accounting Release Number 15 is a vintage year accounting method approved by FERC, *Vintage Year Accounting for General Plant Accounts*, dated January 1, 1997. Vintage year accounting for group depreciation allows a company to simplify its depreciation method for high-volume, low-cost assets. This depreciation accounting method does not require a company to track these types of assets individually but rather allows for the assets to be systematically retired after their depreciable life. These assets are limited to assets commonly referred to as General Plant excluding land, buildings, and vehicles and transportation equipment.

In his testimony, Mr. Spanos recommends realigning the accumulated depreciation reserve balances to reflect the appropriate Accumulated Depreciation balances going forward for depreciation groups that were calculated in the study. This realignment creates a debit balance of unrecovered reserve, to be amortized separately from the depreciation study.

Q. WHAT IS THE TOTAL DEPRECIATION EXPENSE ADJUSTMENT THAT BLACK HILLS POWER IS PROPOSING?

A. Black Hills Power is proposing a total depreciation expense adjustment of $13,369,161 as shown on Statement J, line 19, column (e). This adjustment allows Black Hills Power to reach the annualized amount that Black Hills Power expects to incur going forward and is based on *Pro Forma* Period plant balances that utilized the proposed depreciation rates.

Q. PLEASE DESCRIBE HOW DEPRECIATION AND AMORTIZATION EXPENSE WAS CALCULATED IN THE COSS?

A. As shown on Schedule J-1, depreciation and amortization expense for assets directly owned by Black Hills Power was calculated by multiplying the year-end adjusted plant balances[6], less any non-depreciable items, by each account's proposed depreciation rate as presented in Exhibit JJS-2 - 2025 Black Hills Power Depreciation Study. This study provides the on-going annual depreciation and amortization expense for the *Pro Forma* Period based on the plant in service at the end of the *Pro Forma* Period. Depreciation and amortization expense for assets owned by BHSC was calculated by multiplying the allocated portion of each allocation basis by the corresponding composite rate of each method of allocation.

[6] The year-end adjusted plant balances include September 30, 2025, Account 101 (Schedule D-3 page 1) and 106 (Schedule D-3 page 2) balances plus pro forma additions (Schedule D-10) less pro forma retirements (Schedule D-11) and CUS and DC Tie related assets (Schedules T-1 and T-2).

Q. WHY WAS A COMPOSITE RATE CALCULATED FOR THE BHSC ASSETS INSTEAD OF USING THE DEPRECIATION RATES FROM THE BHSC DEPRECIATION STUDY?

A. The composite rate was calculated to accurately determine the depreciation expense that would be allocated to Black Hills Power. For instance, computer software account 391 is allocated to Black Hills Power by multiple allocation factors. Software used to track system outages is used by all electric utilities and uses a blended ratio to allocate those assets to Black Hills Power. Additionally, software used to produce customer bills for both electric and gas customers is allocated based upon the customer count of all regulated utilities. Therefore, to calculate the appropriate amount of depreciation expense for each allocation method, Black Hills Power used the details of the Test Period ending balance and depreciation expense as the basis of its composite rate for BHSC assets.

IX. <u>INCOME TAX EXPENSE</u>

Q. ARE THERE ADJUSTMENTS TO THE INCOME TAX CALCULATIONS ON STATEMENT K?

A. Yes. The federal income tax on schedule K is calculated based on pre-tax net operating income, plus permanent differences times the statutory tax rate less the deferred tax adjustments. Pre-tax net operating income is calculated by taking the adjusted operating income before tax amount from Statement M, page 1, line 12, less the synchronized interest expense calculated on Lines 83-86 on schedule K. The deferred tax adjustments include AFUDC regulatory asset amortization, tax credits, EDIT Amortization, and flow-through of tax repairs which are shown on lines 70-78 of schedule K. The adjustments in column (e) include known and measurable adjustments to the Per Book Test Period balances as of September 30, 2025, to the *Pro Forma* Period ending September 30, 2026. For example, the book and tax plant-related temporary difference on line 39 of schedule K, and the deferred tax adjustments on lines 70-78 are adjusted to include the additions and retirements in the *Pro Forma* Period. The other adjustments in column (e) are to remove items excluded from rate making like the permanent book and tax differences for fines and penalties, club dues, lobbying, entertainment, cash surrender value of life insurance and captive insurance. Book and tax temporary differences that are excluded from rate making are also removed in column (e) as well. Columns (g) and (h) remove the CUS and DC Tie from the tax expense calculation. The sum of these calculations results is an adjusted income tax expense in the amount of ($12,152,550), as shown on Statement K, line 81, Column (f). Tax expense is negative because of the customer benefits of tax credits, EDIT amortization, and the flow through of tax repairs. When combined with the tax expense related to the additional revenue required on Statement M, page 1 on line 14, column (g) of $11,544,250, the total tax expense before gross-up is $94,014.

Q. PLEASE SUMMARIZE SCHEDULE K-1.

A. Schedule K-1, as required by ARSD Rule 20:10:13:89, provides a reconciliation of the book net income with the taxable net income for calendar years 2020-2024.

Q. PLEASE EXPLAIN SCHEDULE K-2.

A. ARSD 20:10:13:90 requires Black Hills Power to show the computation of the tax depreciation since it may differ from book depreciation.

Q. PLEASE EXPLAIN THE PURPOSE OF SCHEDULE K-3.

A. Since Black Hills Power is one of the companies included in a consolidated federal income tax return, the purpose of Schedule K-3 is to show the net taxable income of each company including adjustments as required by ARSD 20:10:13:91.

Q. PLEASE SUMMARIZE SCHEDULE K-4.

A. Schedule K-4, as required by ARSD 20:10:13:92, provides the working papers for an allowance for current income tax greater than tax calculated at a consolidated rate. Black Hills Power shows the calculation of income tax for the COSS on Statement K.

Q. WHAT IS THE PURPOSE OF SCHEDULE K-5?

A. Schedule K-5 provides detailed information for claimed allowances relating to state income taxes and is a required schedule for ARSD 20:10:13:93.

X. TAXES OTHER THAN INCOME

Q. WHAT ARE TAXES OTHER THAN INCOME?

A. Taxes Other Than Income ("TOTI") are amounts paid to Federal, State, and local governments for revenues not associated with income. These taxes are: FICA, federal and state unemployment taxes, Sales/Use tax, property taxes, franchise taxes, and other payroll taxes.

Q. ARE THE AMOUNTS RECORDED IN THE TEST PERIOD REPRESENTATIVE OF THE TEST PERIOD?

A. Sales/Use Taxes and Other payroll taxes are representative of the Test Period, but FICA, unemployment taxes, and property taxes are not representative of the Test Period.

Q. PLEASE EXPLAIN THE FICA TAX ADJUSTMENT.

A. The proposed adjustment to labor expenses impacts the amount of FICA tax that Black Hills Power will be required to pay. The adjustment captures this increase by multiplying the wage adjustment from Schedule H-5 by the FICA rate, resulting in a pro forma adjustment of $187,943, as shown on Schedule L-1, line 4.

In addition, Black Hills Power adjusted the BHSC Allocated Labor on Schedule H-4. Due to this increase in labor, Black Hills Power also needed to include a FICA adjustment for BHSC labor. The adjustment captures this increase by multiplying the wage adjustments from Schedule H-4 by the FICA rate, resulting in a pro forma adjustment of $268,555, as shown on Schedule L-1, line 26.

Q. PLEASE EXPLAIN THE ADJUSTMENTS FOR UNEMPLOYMENT TAXES.

A. Like the FICA tax adjustment, the federal and state unemployment tax will be impacted by the labor expense adjustments on Schedule H-5. Black Hills Power includes an adjustment that multiplies the additional headcount in the Test Period by FUTA cost per employee, resulting in pro forma adjustments of $336 for FUTA as shown on Schedule L-1, line 9. The SUTA employment tax adjustment is based on the taxable growth amount multiplied by the additional headcount in the Test Year to arrive at taxable earnings, which is multiplied by the SUTA rate for as shown on Schedule L-1, line 16 and results in an adjustment of $144.

Q. WHY ARE TEST PERIOD PROPERTY TAXES NOT REPRESENTATIVE OF THE *PRO FORMA* PERIOD?

A. There are two reasons why Test Period property taxes are not representative of the *Pro Forma* Period. First, the Test Period expense recorded includes out of period adjustments related to the timing that occurs each year for the property tax expense estimated and that were actually incurred during the Test Period. Second, the Test Period Property tax expense does not represent the pro forma plant additions that will be placed in service when rates from this proceeding become effective.

Q. PLEASE EXPLAIN THE PROPERTY TAX OUT OF PERIOD ADJUSTMENTS?

A. Property tax bills showing current year mill levy rates are received between April and June for the previous tax year; therefore, each calendar year's expense is estimated from the appraisal until the final total tax amount is known when the tax bills are received. This process skews the annual expense recorded for both the prior year's true up and the true up to be made in the following year. Removing the out of period adjustment increases property tax expense by $226,923 as shown on Statement L, line 30.

Q. PLEASE EXPLAIN THE PROPERTY TAX ADJUSTMENT RELATING TO PLANT ADDITIONS ON SCHEDULE L-1?

A. The Test Period property tax expense is based on the ending plant balances as of September 30, 2025. Black Hills Power adjusted the Test Period plant balances to reflect the September 30, 2026, plant balances and must adjust the property tax expense in order to maintain symmetry between the plant balances and the property tax expense.

Q. HOW WAS THE PROPERTY TAX EXPENSE ADJUSTMENT CALCULATED FOR THE PLANT ADDITIONS?

A. Black Hills Power calculated a ratio of property tax expense to plant balances. The resulting percentage ("Property to Gross Plant Factor") is calculated by multiplying the 2025 estimated Mill Levy rate against the 2025 assessed value to estimate the 2025 taxes. This tax amount is then divided by the total plant in service for the same time period.

Using this calculation is a reasonable estimate of incremental property tax expense expected from each dollar of Capital Additions and results in 0.4351% of the gross plant additions to be the incremental property tax expense for the *Pro Forma* Period. The plant balance for Black Hills Power at the end of the proposed *Pro Forma* Period is multiplied by the Property to Gross Plant Factor which results in the pro forma year property tax expense. The difference between the Test Period and *Pro Forma* Period property tax expense results in an adjustment of $380,133. This calculation is shown on Schedule L-1, lines 19 through 21.

XI. REVENUES

Q. HOW DO REVENUES IMPACT THE COST OF SERVICE?

A. Revenues do not impact the calculation of the cost of service. Revenues are used as the measure of whether a company is receiving the required revenues calculated in the study. The difference between the revenues received and the revenue requirement is the Revenue Deficiency (if the revenues received are less than the revenue requirement) or the Excess Revenues (if the revenues received are more than the revenue requirement) and is shown on Schedule M-1 of the COSS.

Q. HOW WERE THE *PRO FORMA* PERIOD REVENUES DEVELOPED FOR PURPOSES OF THE COSS?

A. Statement I page 1 of the COSS summarizes the per book revenues and the pro forma adjustments to provide the amounts used to calculate the revenue deficiency on Schedule M-1. Black Hills Power incorporated the Revenues for the *Pro Forma* Period as calculated and explained by Mr. Fritel in his direct testimony.

Statement I, page 2 provides the per book and adjusted energy sales and billing revenue for only South Dakota customers by classification. Statement I, page 3 provides the per book and pro forma energy sales and billing revenue for only South Dakota customers by classification.

Q. PLEASE LIST THE ADJUSTMENTS MADE TO THE PER BOOK REVENUES.

A. See Table LJM-7 below for a listing of the Revenue Adjustments:

Table LJM-7: Revenue Adjustments

Revenue Adjustments	
Schedule I-1	Unbilled & Other Revenue Adjustment
Schedule I-2	ECA Revenue Adjustment
Schedule I-3	Renewable Ready Revenue Adjustment
Schedule I-4	Contract Revenue Adjustment
Schedule I-5	Demand Revenue Adjustment
Schedule I-6	CUS and DC Tie Revenue Adjustment
Schedule I-7	Billing Determinants Synchronization Adjustment
Schedule I-8	Weather Normalization Adjustment
Schedule I-9	Incremental Growth Adjustment
Schedule I-10	Spare Turbine Revenue Adjustment
Schedule I-11	Black Hills Power Shared Facilities Revenue Adjustment
Schedule I-12	Gillette Energy Complex Revenue Adjustment
Schedule I-13	Renewable Ready Revenue Credit

Q. PLEASE EXPLAIN THE UNBILLED AND OTHER REVENUE ADJUSTMENT ON SCHEDULE I-1.

A. Schedule I-1 removes unbilled electric and other revenues. Unbilled revenues represent revenue that is recorded during the per book Test Period that is associated with activity outside of that period. For this reason, the unbilled electric base rate revenues in the amounts of $72,423 are removed from the per book revenues, as shown on Schedule I-1, line 47, column (c). In addition, the COSS includes an adjustment for an atypical loss on material in the amount of ($44,535) as shown on Schedule I-1, line 47, column (d). The total adjustment of ($27,889) is shown on Schedule I-1, line 47, column (e).

Q. WHAT IS THE ENERGY COST ADJUSTMENT ("ECA") REVENUE ADJUSTMENT ON SCHEDULE I-2?

A. This adjustment removes ($46,358,923) for ECA revenues, ($43,990,354) for base fuel and transmission costs included in retail revenue accounts, and ($27,178,421) for Power Marketing Revenues since they are all recovered outside of base rates. The total adjustment removes ($117,527,698) as shown on Schedule I-2, line 47, column (d) through column (e).

Q. PLEASE DESCRIBE THE RENEWABLE READY REVENUE ADJUSTMENT ON SCHEDULE I-3.

A. Renewable Ready Test Period revenues of $3,131,196 are removed from base revenues and are replaced with the Renewable Ready revenue credit updated for the *Pro Forma* Period on Schedule I-13.

Q. WHAT IS THE CONTRACT REVENUE ADJUSTMENT ON SCHEDULE I-4?

A. This adjustment removes the contract revenue associated with the Neil Simpson CT II generating facility, which is owned by the City of Gillette, but it is operated by Black Hills Power. The adjustment of ($561,820) is shown on Schedule I-4, line 47, column (d).

Q. PLEASE EXPLAIN HOW THE DEMAND REVENUE ADJUSTMENT WAS CALCULATED ON SCHEDULE I-5.

A. The demand revenue adjustment normalizes revenue between the Test Period and the *Pro Forma* Period due to unexpected outages in the Test Period. The adjustment of $606,620 is shown on Schedule I-5, line 47, column (e).

Q. WHY WAS REVENUE RELATING TO THE CUS AND DC TIE REMOVED ON SCHEDULE I-6?

A. Revenue relating to the CUS and DC Tie are removed since it is generated through the FERC ratemaking process. CUS revenue in the Test Period was $36,784,514 as shown on Schedule I-6, line 47, column (c). DC Tie revenue in the Test Period was $3,292,800 as shown in Schedule I-6, line 47, column (d). The total adjustment of ($40,077,314) is shown on Schedule I-6, line 47, column (e).

Q. PLEASE EXPLAIN THE BILLING DETERMINANT SYNCHRONIZATION ADJUSTMENT ON SCHEDULE I-7.

A. The billing determinant synchronization adjustment is required to synchronize the revenues calculated using the billing determinants and the revenues from the accounting system for the 12-month period ending September 30, 2025, in the amount of $118,386, as shown on Schedule I-5, line 47, column (d). Mr. Fritel further explains this adjustment in his direct testimony.

Q. PLEASE DESCRIBE THE WEATHER NORMALIZATION ADJUSTMENT ON SCHEDULE I-8.

A. To adjust the revenues to reflect normal weather, an adjustment is made to reduce revenues by ($512,306), as shown on Schedule I-8, line 47, column (c). This adjustment and its calculation is discussed further by Mr. Fritel.

Q. WHAT IS THE INCREMENTAL GROWTH ADJUSTMENT ON SCHEDULE I-9?

A. The incremental revenue growth adjustment for customer growth is based upon the forecasted number of customers as of September 30, 2026. The adjustment results in a revenue increase of $697,457, as shown in Schedule I-9, line 47, column (c). Mr. Fritel discusses how this adjustment is calculated in his direct testimony.

Q. PLEASE EXPLAIN THE SPARE TURBINE REVENUE ADJUSTMENT ON SCHEDULE I-10.

A. Black Hills Power owns shared spare turbines that can be utilized by affiliate companies when not in use in its own generating facilities. An adjustment of ($2,825,874) is shown on Schedule I-10, line 47, column (d) because Black Hills Power is requesting that the revenue be excluded from base rates. Mr. Keil discusses in his direct testimony how the revenue and its associated expenses on Schedule H-21 are proposed to be recovered through the Spare Turbine Adjustment Rider (STAR).

Q. PLEASE EXPLAIN THE BLACK HILLS POWER SHARED FACILITIES REVENUE ADJUSTMENT ON SCHEDULE I-11.

A. Black Hills Power owns BHC's Horizon Point Corporate Headquarters in Rapid City, South Dakota, and receives rent revenue from BHSC for its use. Mr. Keil discusses the ownership of Horizon Point and the calculation of its rent revenue in his direct testimony.

An adjustment of ($40,300) is shown on Schedule I-11, line 33, column (d) which represents the decrease in rental income for the *Pro Forma* Period.

Q. PLEASE DESCRIBE THE GILLETTE ENERGY COMPLEX REVENUE ADJUSTMENT ON SCHEDULE I-12.

A. Black Hills Power receives rent from the shared assets at the Gillette Energy Complex which is described in the direct testimony of Mr. Lux. An adjustment of $739,745 is shown on Schedule I-12, line 42, column (d) to account for additional revenue expected from affiliate companies and co-owners of generating facilities at the complex.

Q. WHAT IS THE RENEWABLE READY REVENUE CREDIT ON SCHEDULE I-13?

A. A revenue credit is calculated to replace the revenues removed on Schedule I-3, utilizing a revenue requirement calculation with updated rate base, expenses, depreciation rates, capital structures, and debt and equity costs from this Application, on the Corriedale Renewable Ready assets to ensure there is no customer rate impact for the rate base included in the revenue requirement computation. As set forth in Docket No. EL18-060, the Renewable Ready Revenue Credit is set at the guaranteed minimum of $2,320,000 as shown on Schedule I-13, line 30, column (f).

XII. STATEMENT P

Q. PLEASE DESCRIBE STATEMENT P.

A. Statement P is required in ARSD 20:10:13:61 to show the derivation for the cost adjustment factor as stated therein.

Statement P, page 1 shows the calculation of the derivation of the base unit cost for the fuel and purchase power adjustment. Black Hills Power is adjusting the Power

Cost Base Rate per kWh to $0.03324 based on current costs.[7] Since property taxes above or below specified base amount are included in the Fuel and Purchased Power Adjustment, Black Hills Power is also requesting to reset the base amount to $6,261,174 as calculated in the COSS.

Statement P, page 2 shows the calculation of the derivation of the base unit cost of transmission. Black Hills Power is adjusting the Base Unit Cost for Transmission to $0.01315 based on current costs.[8]

XIII. STATEMENT R COAL PRICING

Q. PLEASE EXPLAIN THE COAL SUPPLY ARRANGEMENT FOR BLACK HILLS POWER'S COAL FIRED POWER PLANTS.

A. Black Hills Power has a Coal Supply Agreement with Wyodak Resources to provide coal to Black Hills Power's coal-fired power plants. The pricing for the Coal Supply Agreement is based on what Black Hills Power refers to as 'Statement R' pricing because it has historically corresponded to the Statement in the rate case application that details the coal price calculation for coal purchased from Black Hills Power's affiliate. Under this methodology, Black Hills Power's coal costs are determined by calculating the amount that allows Wyodak Resources to recover its cost of service related to the coal sales to Black Hills Power, plus a return on investment. That return is the average interest rate for new, long-term A-rated utility bonds issued during the calendar year for which the calculation is being made, plus four hundred basis points. This is a utility type rate of return methodology. This methodology has been presented and accepted by this

[7] Existing Power Cost Base Rate per kWh was approved in Docket EL09-018.
[8] Existing Power Cost Base Rate per kWh was approved in Docket EL09-018.

Commission previously in multiple filings for Black Hills Power. In addition, this pricing methodology has been accepted by third parties with ownership interests at the Gillette Energy Complex such as the City of Gillette and Montana Dakota Utilities Co.

Q. DO BLACK HILLS POWER'S CUSTOMERS BENEFIT FROM THE EXISTENCE OF THE COAL SUPPLY AGREEMENT?

A. Yes. The coal supply arrangement is beneficial to Black Hills Power's customers for several reasons. All remaining coal-fired power plants are mine-to-mouth facilities which helps eliminate almost all transportation costs. In addition, the Coal Supply Agreement is a long-term supply agreement, providing coal for the life of the facilities.

XIV. <u>STATEMENT T TRANSMISSION ADJUSTMENTS</u>

Q. PLEASE EXPLAIN THE PURPOSE OF STATEMENT T.

A. Statement T removes from the COSS the rate base components and the expenses related to both the DC Tie and the CUS, as these costs are recovered separately through the FERC ratemaking process.

Q. PLEASE SUMMARIZE SCHEDULE T-1.

A. Schedule T-1 determines and removes the portion of rate base components and expenses attributable to the DC Tie that should be excluded from the COSS. This calculation is performed in accordance with the FERC approved cost-of-service methodology used to establish rates for DC Tie customers.

Q. PLEASE DESCRIBE SCHEDULE T-2.

A. Schedule T-2 identifies and removes from the COSS the rate base components and expenses attributable to the CUS. This calculation is performed in accordance with the

FERC approved cost-of-service methodology used to establish the rates charged to transmission customers.

XV. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The COSS presented in my testimony provides a comprehensive and well-supported assessment of Black Hills Power's revenue requirement for the South Dakota jurisdiction. By starting with the Company's per-book financials for the Test Period and applying known and measurable adjustments through the *Pro Forma* Period, the study ensures that the resulting COSS reflects the costs necessary to provide safe, reliable, and efficient electric service to customers when new rates become effective.

The adjustments described throughout my testimony, spanning rate base, operating expenses, depreciation, taxes, and revenues, were developed using industry-accepted regulatory principles and data-driven methodologies. The resulting South Dakota revenue requirement supports a jurisdictional increase of $50,553,697, which is necessary for Black Hills Power to recover its prudently incurred costs and to maintain a reasonable opportunity to earn the authorized return.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

VERIFICATION

This Direct Testimony and Exhibits of Lori J. Mack is true and accurate to the best of my knowledge, information, and belief.

/s/ *Lori J. Mack*
Lori J. Mack