Direct Testimony and Exhibits
Amanda M. Thames

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 Approval of its Phase-In Rate Plan Tariff Revisions

Docket No. EL26-_____

August 4, 2026

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EXHIBITS

TABLE OF ABBREVIATIONS AND ACRONYMS

1898	1898 Co.
BA	Balancing Authority
B&V	Black and Veatch
BHC	Black Hills Corporation
BHSC	Black Hills Service Company, LLC
Black Hills Power	Black Hills Power, Inc. d/b/a Black Hills Energy
Cheyenne Light	Cheyenne Light, Fuel, and Power Company
ELCC	Effective Load Carrying Capability
IRP	Integrated Resource Planning
kWh	Kilowatt hour
LOLE	Loss of Load Expectation
L&R	Load and Resource Balance
NERC	North American Electric Reliability Corp
NW-NE	Northwest - Northeast
PRM	Planning Reserve Margin
PVRR	Present Value of Revenue Requirements
RICE	Reciprocating Internal Combustion Engine
SPP	Southwest Power Pool
WECC	Western Electricity Coordinating Council

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Amanda M. Thames. 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 subsidiary of Black Hills Corporation ("BHC"), as Manager of Resource Planning.

Q. PLEASE DESCRIBE YOUR EDUCATION AND BUSINESS BACKGROUND.

A. I am a graduate of the University of North Dakota in Grand Forks, North Dakota, with a Bachelor of Science Degree in Industrial Technology. I began my career with Black Hills Corporation in 2012 in the Resource Planning Department as a Resource Planning Analyst. I have 14 years of experience in the electric utility industry, focused on resource planning, with progressively increasing responsibilities. In this role, I provided support to Black Hills Corporation's electric utility subsidiaries by providing analytical assistance and strategic business support specific to the adequacy of electric energy and capacity and the costs of that energy and capacity to serve our customers' needs in the jurisdictions of South Dakota, Wyoming, Montana, and Colorado. I have held my current position as Resource Planning Manager since March 2021.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION.

A. I am responsible for managing the long-range resource planning analysis, which includes capacity expansion modeling, production cost modeling, and scenario analysis. These analyses are utilized as the basis for the Company's Integrated Resource Planning

("IRP") efforts. I also oversee modeling results for all BHSC regulated electric utilities, including Cheyenne Light. In this role, I oversee production cost modeling for internal processes like budgeting and internal analysis, which also involves overseeing the various resource planning and procurement processes across BHSC's regulated entities. I am also responsible for Western Electricity Coordination Council ("WECC") reporting and North American Electric Reliability Corporation ("NERC") standards compliance.

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. My testimony explains the need for and selection of the Lange II Project to meet Black Hills Power's capacity deficit, the analytical steps and reserve margin determination supporting the project.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibits:

Confidential Exhibits AMT-1	Busbar Cost Study
Exhibit AMT-2	Planning Reserve Margin and Effective Load Carrying Study
Exhibit AMT-3	Overview of Load Forecasting Models
Exhibit AMT-4	Load and Resource Balance Study
Confidential Exhibit AMT-5	Hitachi Energy IRP Modeling Summary

III. THE LANGE II PROJECT

Q. PLEASE PROVIDE A DESCRIPTION OF THE LANGE II PROJECT.

A. The Lange II Project is a 97.4 MW net capacity (99.6 MW nameplate capacity) generating facility that will consist of six 16.6 MW dual-fuel (natural gas and diesel) Reciprocating Internal Combustion Engine ("RICE") generating units, and related facilities, which will address a capacity deficit for Black Hills Power. The units will be constructed within the city of Rapid City, Pennington County, South Dakota on land owned by Black Hills Power and adjacent to Black Hills Power's existing Lange combustion turbine. Natural gas will be supplied to the Lange II Project through the existing natural gas pipeline currently serving the existing Lange combustion turbine, and diesel fuel will be purchased from the market and stored in liquid fuel tanks at the Lange II Project site. The Lange II Project will electrically interconnect into the Black Hills Power transmission system at the existing Lange substation. The Lange II Project has an estimated cost of $320.4 million. A more detailed description of the project can be found in the Direct Testimony of Mr. Mark L. Lux (Exhibit 5 to the Application).

Q. PLEASE DESCRIBE THE NEED THAT LED TO THE DEVELOPMENT OF THE LANGE II PROJECT.

A. The Lange II Project was identified as the least cost resource to address a capacity deficit on the Black Hills Power system. This deficit is the result of the retirement of the aging Ben French generating units[1] and a change in the Planning Reserve Margin ("PRM") for Black Hills Power, discussed further below.

[1] The Ben French units are located in Rapid City, South Dakota and consist of four dual-fuel simple cycle CTs (100 MW total), operating since the late 70's, and five diesel units (10 MW total), operating since the mid-60's.

Q. PLEASE DESCRIBE THE BLACK HILLS POWER GENERATING UNITS THAT ARE SCHEDULED FOR RETIREMENT.

A. Black Hills Power has nine diesel and dual fuel (natural gas and diesel) units located in Rapid City, South Dakota that are retirement age collectively referred to as the Ben French units. This includes five 2 MW diesel units (Ben French Diesels 1 – 5) commissioned in 1965, and four 25 MW nameplate capacity dual-fuel simple cycle combustion turbines (Ben French SCCTs 1 – 4 or "Ben French Turbines") commissioned in 1977-1979. Retirement of these units represents a combined 82 MW summer capacity reduction[2] of the Black Hills Power generation fleet and results in the loss of two black-start[3] units designated for the Black Hills Power system.

Q. WHEN ARE THE BEN FRENCH UNITS SCHEDULED FOR RETIREMENT?

A. The Ben French Turbines are nearing end of life and are planned to be retired in 2027. A more detailed discussion of the Ben French units and their planned retirement can be found in the Direct Testimony of Mark L. Lux.

Q. WHAT IS A PLANNING RESERVE MARGIN?

A. A Planning Reserve Margin ("PRM") is the percentage of capacity above the system peak demand needed to ensure a utility has a reliable energy supply. This ensures that the demand and energy needs of customers can be met by taking into account generating resource characteristics and outage rates, load forecast uncertainty, or other unforeseen events. The analysis used an industry standard 1-day-in-10-year Loss of Load Expectation ("LOLE") reliability metric or limiting the period of potential energy

[2] Summer capacity is lower than nameplate capacity due to ambient conditions.
[3] A black-start unit is a generating unit that is capable of starting up and producing electricity without relying on power from the main grid and used as the initial source of power to bring a system back online.

shortfall to be 0.1 days (2.4 hours) per year. This reliability metric is used to determine how much generating capacity margin is statistically needed to limit the number of hours where there would be an energy shortfall to 24 hours in ten years which could be caused by unforeseen events. This is a commonly used energy supply risk management tool to support supply reliability.

Q. PLEASE EXPLAIN THE PRM UTILIZED BY BLACK HILLS POWER.

A. In the analysis that identified the need for the Lange II Project, Black Hills Power utilized a 30% PRM. Historically, Black Hills Power has utilized a 15% PRM, as that was generally consistent with the historical PRM range in the electric industry. With PRM standards generally evolving throughout the electric industry, Black Hills Power engaged 1898 & Co. ("1898") to study the appropriate PRM for the combined Black Hills Power and Cheyenne Light, Fuel and Power Company ("Cheyenne Light") resource mix and combined load characteristics. The results of that study determined that a 30% PRM meets the LOLE metric and results in prudent planning for Black Hills Power in order to ensure safe and reliable service for customers. See Exhibit AMT-2 – Planning Reserve Margin and Load Carrying Study.

Q. WHY WAS THE PRM CALCULATED FOR THE COMBINED BLACK HILLS POWER AND CHEYENNE LIGHT SYSTEMS?

A. Black Hills Power and Cheyenne Light have the ability to procure planning reserves from one another on a short-term (31 days or less) basis through a Planning Reserve Agreement. The ability to meet short-term requirements in this way allows the PRM to be calculated for a combined Black Hills Power and Cheyenne Light system, which results in a lower combined PRM compared to standalone utility PRMs due primarily to the increased overall size of the system being evaluated.

Q. PLEASE DESCRIBE THE FACTORS CONSIDERED BY 1898 IN THE STUDY REFERENCED.

A. 1898 considered the capabilities of the combined system under varying customer demand, generation unit outages, and renewable generation production profiles. Perfect generation[4] was added to the portfolio to calibrate to the LOLE reliability metric. Next, solar, wind, and storage were removed, then perfect generation was added to recalibrate the portfolio. The amount of perfect generation needed to replace solar, wind and storage was used to calculate the PRM. Additionally, six resource scenarios were evaluated in addition to the base case to reflect varying levels of solar, wind, and storage resources. Each of these cases resulted in an approximately 30% PRM.

Q. PLEASE EXPLAIN WHY AN INCREASE IN THE PRM IS APPROPRIATE AT THIS TIME.

A. The electric utility industry has refined the determination of appropriate reserve margins in recent years, incorporating more detailed analysis of utilities on an individual and regional basis. Historically, all utilities, no matter the size of the utility or the generation resources available, often utilized a 15% PRM. With a more utility-by-utility analysis, PRMs have now become more utility specific which has resulted in broader ranges of PRMs to more accurately account for each utility's load, geographical location, and generation availability and composition. Since all these factors can influence the PRM for

[4] "Perfect generation" describes a hypothetical resource that is available at full capacity all hours of the year. While no resource is truly perfect, this hypothetical resource provides a useful benchmark against which to measure the capacity value of real-world resources.

a utility, it is more appropriate to use a utility-specific PRM than the general PRM used in the past.

Q. PLEASE EXPLAIN WHY THE SIZE OF THE UTILITY AND GENERATING UNITS IMPACT THE PRM.

A. The larger the percentage of total generating capacity that comes from a single generating unit increases the system impact of an outage of a large generator. This, in turn, increases the PRM percentage necessary to ensure reliable service.

Q. ARE INCREASING PRMs COMMON IN THE INDUSTRY?

A. Black Hills Power is not alone in seeing increased PRM requirements. In fact, more load serving entities are trending towards a higher PRM requirement. One example is Southwest Power Pool's ("SPP") increasing annual and seasonal planning reserve margins for their member utilities, shown in the table below.

Table AMT-1: Annual and Seasonal Planning Reserve Margins

Effective Year	Annual (%)	Summer (%)	Winter (%)
2030[5]		17	38
2029[6]		17	38
2026/2027[7]		16	36
2023[8]	15		
2017[9]	12		

WECC uses the same 1-day-in-10-year, or 99.98 percent reliability threshold, as their standard. This is a utility best practice when it comes to system reliability. Like SPP's trending PRM increase over time, WECC has found similar results, displayed in

[5] 26-04-03 SPP Board Member Recommendations
[6] 25-02-04 board members committee minutes.pdf
[7] 24-08-06 board members committee minutes.pdf
[8] bod_mc minutes 2022 07 26.pdf
[9] bod_mc minutes 20160426_full.pdf

the tables below. These tables provide the values for both the WECC and the Northwest – Northeast ("NW-NE") subregion, which includes Black Hills Power.

Table AMT-2: 2021 Western Assessment of Resource Adequacy Report[10]

Region	Total Reliability PRM (%)		Peak PRM (%)
	2022	2031	2022
WECC	16.9		13.6
NW-NE	23.9	22.7	13.9

Table AMT-3: 2024 Western Assessment of Resource Adequacy Report[11]

Region	Total Reliability PRM (%)		Peak PRM (%)	
	2028	2034	2028	2034
WECC	27.6	31.5	18.8	22.1
NW-NE	32.5	35.9	14.2	15.5

WECC found that using a peak PRM[12] instead of a total reliability PRM[13] would result in several thousand hours with projected energy shortfalls. Looking specifically at the NW-NE subregion, WECC found that using a 14% peak PRM would put almost all hours of the year at risk.[14]

The SPP and WECC PRM results indicate that Black Hills Power's increased PRM not only aligns with increasing PRMs industry wide but is also of reasonable magnitude to support system reliability.

[10] https://www.wecc.org/sites/default/files/documents/program/2024/WARA%202021.pdf
[11] 2024 WECC PRM Analysis.pdf
[12] PRM needed to ensure the peak hour is 99.98 percent reliable.
[13] PRM needed to ensure all hours of the year are 99.98 percent reliable.
[14] 2024 PRM Analysis.pdf

Q. DOES THE RETIREMENT OF THE BEN FRENCH UNITS AND THE INCREASED PRM DRIVE THE CAPACITY NEED?

A. Yes. The retirement of the Ben French diesel and dual-fuel units, combined with an increased PRM, is driving the need for capacity.

IV. SUPPORTIVE ANALYSIS FOR THE LANGE II PROJECT

Q. PLEASE DESCRIBE THE ANALYSIS BLACK HILLS POWER CONDUCTED THAT SUPPORTS THE LANGE II PROJECT.

A. Black Hills Power initiated several studies to meet the capacity needs of its customers on a least cost basis. Specifically, Black Hills Power conducted the Busbar Cost Study, a PRM and Effective Load Carrying Capability ("ELCC") study, a review of the load forecast, a Load and Resource Balance ("L&R") study, and capacity expansion and production cost analysis. See Confidential Exhibit AMT-1 - Busbar Cost Study, Exhibit AMT -2 - Planning Reserve Margin and Effective Load Carry Study, Exhibit AMT -3 - Overview of Load Forecasting Models, and Exhibit AMT-4 -Load and Resource Balance Study. These studies resulted in the selection of the Lange II Project as the least cost solution for customers.

Q. PLEASE DESCRIBE THE LOAD FORECASTING MODELS UTILIZED IN THE ANALYSIS THAT RESULTED IN THE LANGE II PROJECT.

A. The analysis that led to the Lange II Project began with a long-term energy and demand forecast for Black Hills Power conducted by Christiansen Associates Energy Consulting, LLC. See Exhibit AMT -3 - Overview of Load Forecasting Models This analysis was conducted in order to determine the expected loads for the utility in order to then identify any need for additional resources. Generation resources take time to procure, so a long-term view of energy needs of the utility is a routine analysis conducted by Black Hills Power and supports requested additions of generation resources.

Q. PLEASE DESCRIBE THE LOAD FORECAST MODEL OF BLACK HILLS POWER.

A. The load forecast model of Black Hills Power employs an econometric, weather-normalized forecasting methodology to forecast retail peak demand and energy. A variety of different types of datasets, including historical load, economic, and weather data are used to develop regression models for the demand and energy forecasts. Large customer loads and transmission and distribution losses are then included to create the final system load forecasts. The final system load forecast for Black Hills Power resulted in a 0.5% annual demand growth rate and a 0.2% annual energy growth rate.

Q. PLEASE DESCRIBE THE NEXT STEP IN THE ANALYSIS FOLLOWING THE LOAD FORECAST MODELING.

A. The next step in the analysis that led to the Lange II Project selection was to take the load forecast and conduct a load and resource balance study.

Q. PLEASE DESCRIBE THE LOAD AND RESOURCE BALANCE STUDY.

A. The Load and Resource Balance Study looked at the Black Hills Power forecasted peak demand from 2025 through 2043 in relation to the current available resources and planned retirement of resources. See Exhibit AMT - 4 – Load and Resource Balance Study. Available resources include owned resources and contracted resources, while total load includes forecasted retail load, sales contracts, and 30% PRM. The analysis identifies the excess or deficit capacity of the system for the analyzed period of time.

Q. PLEASE DESCRIBE THE RESULTS OF THE LOAD AND RESOURCE BALANCE STUDY.

A. The Load and Resource Balance Study identified a deficit on the Black Hills Power system beginning in 2025 and continuing through the analyzed time period, which indicates the need for additional resources.

As load changes, owned or contracted resources retire, or sales contracts expire, the resulting capacity balance (excess or deficit) will fluctuate. While these fluctuations can be seen in the load and resource report, the capacity deficit remains in each year, illustrating a long-term need for additional capacity resources.

Q. PLEASE DESCRIBE THE NEXT STEP IN THE ANALYSIS FOLLOWING THE LOAD AND RESOURCE BALANCE STUDY.

A. Once the Load and Resource Balance Study was completed and a long-term capacity need was identified, Black Hills Power utilized the Busbar Cost Study conducted by Black & Veatch ("B&V") to identify appropriate capacity resource options to address the identified deficit. See Confidential Exhibit AMT -1 – Busbar Cost Study. A busbar study analyzes the cost and performance characteristics of various generation resources and serves as an input to the capacity expansion analysis that ultimately identifies the capacity resource solution or portfolio for customers.

Q. PLEASE DESCRIBE THE BUSBAR COST STUDY.

A. The Busbar Cost Study identified the cost and performance characteristics of approximately 40 technologies for Black Hills Power. Table 1-1 of Confidential Exhibit AMT -1 identifies the 40 technologies included in the B&V Busbar Cost Study. B&V developed a busbar model that included the costs for proposed resources – capital, fuel, and operation and maintenance costs – on a levelized cents per kilowatt-hour (kWh) basis for a period of 25 years, except for battery storage technology, which was evaluated for a 20-year period.

Q. PLEASE IDENTIFY THE ASSUMPTIONS USED IN THE BUSBAR COST STUDY.

A. The Busbar Cost Study utilized numerous assumptions in the analysis of costs associated with the potential Black Hills Power generation resource solutions. These include inflation and escalation rates, weighted average cost of capital, present value discount rate, levelized fixed charge rate, fuel pricing, and owner's cost. See Confidential Exhibit AMT -1 - Section 2. These assumptions are necessary to properly evaluate a comparable per kWh cost of energy from the different types of resources.

Q. PLEASE DESCRIBE THE TYPE OF TECHNOLOGIES OR RESOURCES CONSIDERED IN THE BUSBAR COST STUDY.

A. The generic technologies evaluated included baseload, peaking, and renewable technologies, encompassing natural gas, wind, solar, biofuel, geothermal, pumped hydro, battery storage, long duration energy storage, carbon capture, small-scale nuclear, hydrogen, and fuel switching of existing units. See Confidential Exhibit AMT -1 - Section 4.

Q. PLEASE DESCRIBE THE CAPACITY FACTOR THAT WAS USED IN THE BUSBAR ANALYSIS FOR THE CANDIDATE UNITS.

A. The Busbar Cost Study utilized a resource capacity factor range of 40% to 90%, in increments of 10% for baseload units, and a range of 5% to 35%, in increments of 10%, for peaking units. Renewable facilities utilized a capacity factor based on historical data and Black Hills Power projections as well as capacity factor deviations of 3 percentage points higher and lower than the initial capacity factor. Storage was assumed to operate at an average frequency of one charge and discharge cycle per day, with additional sensitivities based on energy storage type. Specifically, typical 4-hour duration battery energy storage system had a range of 0.5 to 2 cycles per day. Long duration energy storage assumed one cycle per day, one cycle every three days, and one cycle each week.

Q. PLEASE DESCRIBE HOW THE RESULTS OF THE BUSBAR COST STUDY ARE UTILIZED.

A. The results of the Busbar Cost Study were used to create a busbar cost curve that includes all candidate resources for each category of resource (baseload, peaking, solar, wind, and battery storage) and charts each candidate resource on a cost basis. See Confidential Exhibit AMT -1, Section 4.2.

Q. PLEASE EXPLAIN HOW B&V UTILIZES THE BUSBAR COST CURVE.

A. B&V utilizes the busbar cost curve analysis to recommend a list of screened generation resources within all resource categories (baseload, peaking, solar, wind, and battery storage). Black Hills Power then reviews the recommendations as set forth by B&V and incorporates the busbar resource information into a capacity expansion model that considers multiple factors in addition to cost.

Q. PLEASE EXPLAIN THE NEXT STEP FOLLOWING THE BUSBAR COST STUDY.

A. Black Hills Power took the candidate resources identified by the Busbar Cost Study and analyzed those in the capacity expansion model in order to determine the generation portfolio to address the identified resource deficiency from the Load and Resource Balance Study. See Exhibit AMT -4 – Load and Resource Balance Study.

Q. PLEASE DESCRIBE A CAPACITY EXPANSION MODEL.

A. A capacity expansion model simulates generation capacity investments necessary to reliably and cost effectively meet customer needs utilizing assumptions such as energy and demand forecasts, PRM, fuel and market energy pricing, policies and regulations, and resource cost and performance. The model analyzes numerous future scenarios and identifies the candidate resources from the Busbar Cost Study to select a preferred resource portfolio to address the resource need.

Q. PLEASE DESCRIBE A PRODUCTION COST MODEL.

A. A production cost model simulates the hourly operation of the resources available to a utility and is used to forecast system cost and evaluate risk exposure. A production cost model includes an hourly dispatch model, based upon an hourly load forecast and the system resources available to serve that load, and captures the associated total cost of energy to serve the forecasted load.

Q. PLEASE DESCRIBE THE CAPACITY EXPANSION AND PRODUCTION COST MODELING STEPS AND ASSUMPTIONS.

A. Black Hills Power engaged Hitachi Energy to conduct capacity expansion and production cost modeling to identify appropriate capacity resource options to address the identified capacity deficit and resulting scenario analysis. After the capacity expansion modeling selects the optimal portfolio of resources needed to address the capacity need, the full resource portfolio, including existing resources and resources selected through capacity expansion modeling, are simulated within the production cost model. The production cost model dispatches the portfolio on the more granular hourly level to achieve a more accurate resource dispatch and total cost of energy. See Confidential Exhibit AMT -5 – Hitachi Energy Modeling Summary.

Q. PLEASE SUMMARIZE THE SCENARIOS AND SENSITIVITIES ANALYZED IN THE CAPACITY EXPANSION AND PRODUCTION COST MODELS.

A. The analysis looked at the following scenarios and sensitivities:

Table AMT-4: Modeled Scenarios

Scenario	Assumptions
Base Plan	Assuming existing resources and forecasted load
Low Gas	Assuming low gas costs
High Gas	Assuming high gas costs
Low Load	Assuming a lower than forecasted load
High Load	Assuming a higher than forecasted load
Expanded Energy Market	Assuming impacts of joining an expanded energy market
EPA Greenhouse Gas	Assuming impacts of EPA Greenhouse Gas standards
Data Center	Assuming impacts of a potential large data center load in addition to base forecasted load

The capacity expansion and production cost models used varying assumptions in each of the scenarios to address uncertainty. The static assumptions used across each scenario and sensitivity include financial assumptions, PRM and ELCC, and operational characteristics for existing and candidate resources. The assumptions that are varied among the scenarios are load forecasts, and fuel and market price forecasts, summarized in the table below. The assumptions that are modified from the Base scenario are noted in blue text in Table AMT-5. The assumptions for fuel and market price forecasts, financial assumptions, and scenario definitions are summarized in Confidential Exhibit AMT -5 – Hitachi Energy Modeling Summary.

Table AMT -5: Modeled Scenarios with Sensitivities

Scenario	Base	Low Gas	High Gas	Low Load	High Load	Expanded Energy Market	EPA GHG	Data Center
Load Growth	Median	Median	Median	Low	High	Median	Median	Median + Step
Electric Price	Median	Low	High	Median	Median	Median	Median	Median
Gas Price	Median	Low	High	Median	Median	Median	Median	Median
Resource Selection	Economic	Economic	Economic	Economic	Economic	Base Portfolio	Economic	Economic + Forced in Base

Q. PLEASE DESCRIBE THE RESULTS OF THE CAPACITY EXPANSION AND PRODUCTION COST MODELING.

A. In the scenarios considered, the preferred portfolio selected was the Base Plan scenario which included the addition of five RICE units in 2026 and an additional RICE unit in 2027. As discussed in more detail in the Direct Testimony of Mark L. Lux, for economic efficiencies, the resources selected in 2026 and 2027 were combined into the Lange II Project which includes all six dual-fuel RICE units.

Q. PLEASE DESCRIBE HOW THE PREFERRED PORTFOLIO COMPARES TO THE OTHER SCENARIO PORTFOLIOS CONSIDERED.

A. All eight scenario results include the addition of six RICE units. Six of the scenarios resulted in all six RICE units added by 2027. The Low Load and High Gas scenarios each added five RICE units in 2026 and a sixth RICE unit by 2030. This demonstrates the proposed addition of six RICE units is the preferred least cost resource under a variety of load and fuel cost scenarios.

Q. PLEASE DESCRIBE HOW THE COST OF THE PREFERRED PORTFOLIO COMPARES TO THE OTHER SCENARIO PORTFOLIOS CONSIDERED.

A. The Present Value of Revenue Requirements ("PVRR") of the Base Plan portfolio is $1,214 million dollars. Comparatively, many of the other portfolios have similar PVRRs resulting from similar resource builds, including the Low and High Gas, and Low and High Load scenarios. As seen in the following table, these portfolios are very near the Base Plan value, proving the Base Plan's economic effectiveness:

<u>Table AMT-6: Scenario Economic Results</u>

Scenario	PVRR (Million $)
Base Plan	$1,214
Low Gas	$1,203
High Gas	$1,227
Low Load	$1,221
High Load	$1,234
Expanded Energy Market	$1,149
EPA Greenhouse Gas	$1,319
Data Center	$2,315

Q. PLEASE DESCRIBE HOW THE RICE UNITS COMPARE TO THE OTHER TECHNOLOGIES CONSIDERED.

A. The RICE units, in addition to meeting the utility's capacity needs, will provide operating efficiency. RICE units offer quick start capabilities, are efficient when operating at low or high outputs, and provide much needed flexibility to maintain reliability. As seen in the results of the additional scenarios considered, RICE units perform well under a variety of conditions, including environmental constraints and responding to intermittent resources.

Q. PLEASE DESCRIBE THE INCREASED DISPATCH FLEXIBILITY THE LANGE II PROJECT WILL PROVIDE.

A. The Lange II RICE units can reduce and increase their output quickly to efficiently respond to load and generation changes and take advantage of real-time market price changes. Additionally, each RICE unit can reduce to approximately 6 MW which is a significantly lower minimum generating level than a coal or natural gas generating unit. This dispatch flexibility is discussed in more detail in the Direct Testimony of Mark L. Lux.

Q. DO YOU BELIEVE THE ADDITION OF THE SIX RICE UNITS IS THE LEAST COST SOLUTION FOR CUSTOMERS?

A. Yes. In addition to the Lange II Project being the least cost solution for customers, as discussed in more detail by Mr. Lux, these types of units provide additional benefits to the efficient operation of the Black Hills Power system and provide the opportunity for customer benefits because of the increased dispatchability. The analysis discussed herein was conducted using a range of natural gas pricing, environmental, and load uncertainty scenarios. Throughout each of these varied scenarios, the consistent economic selection of six RICE units demonstrates not only cost-effectiveness but also proves the risk mitigation these units provide in uncertain conditions. Additionally, these units also reduce risk through replacing the resource capacity lost due to the retirement of obsolete generation critical to reliability and support an increased planning reserve margin which mitigates supply risk.

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Lange II Project represents a necessary and prudent investment that, as demonstrated through numerous evaluations and comprehensive studies, provides the least-cost resource option for Black Hills Power customers while ensuring long-term reliability.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

VERIFICATION

This Direct Testimony and Exhibits of Amanda M. Thames is true and accurate to the best of my knowledge, information, and belief.

/s/ Amanda M. Thames
Amanda M. Thames