UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
Form 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2023
Or

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _______________ to _______________

Commission File Number 001-31303

BLACK HILLS CORPORATION

Incorporated in South Dakota IRS Identification Number 46-0458824

7001 Mount Rushmore Road
Rapid City, South Dakota 57702
Registrant's telephone number (605) 721-1700

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol	Name of each exchange on which registered
Common stock of $1.00 par value	BKH	New York Stock Exchange

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the Registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C.7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the voting common equity held by non-affiliates of the registrant on the last business day of the registrant's most recently completed second fiscal quarter, June 30, 2023, was $4,016,297,084

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

Class	Outstanding at January 31, 2024
Common stock, $1.00 par value	68,196,551 shares

Documents Incorporated by Reference
Portions of the registrant's Definitive Proxy Statement being prepared for the solicitation of proxies in connection with the 2024 Annual Meeting of Stockholders to be held on April 23, 2024, are incorporated by reference in Part III of this Form 10-K.

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GLOSSARY OF TERMS AND ABBREVIATIONS

The following terms and abbreviations appear in the text of this report and have the definitions described below:

AC	Alternating Current
AFUDC	Allowance for Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income (Loss)
APSC	Arkansas Public Service Commission
Arkansas Gas	Black Hills Energy Arkansas, Inc., an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Arkansas (doing business as Black Hills Energy).
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update as issued by the FASB
ATM	At-the-market equity offering program
Availability	The availability factor of a power plant is the percentage of the time that it is available to provide energy.
BHC	Black Hills Corporation; the Company
BHSC	Black Hills Service Company, LLC, a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
Black Hills Colorado IPP	Black Hills Colorado IPP, LLC, a 50.1% owned subsidiary of Black Hills Electric Generation
Black Hills Electric Generation	Black Hills Electric Generation, LLC, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings, providing wholesale electric capacity and energy primarily to our affiliate utilities.
Black Hills Energy	The name used to conduct the business of our Utilities
Black Hills Energy Renewable Resources (BHERR)	Black Hills Energy Renewable Resources, LLC, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Energy Services	Black Hills Energy Services Company, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas commodity supply for the Choice Gas Programs (doing business as Black Hills Energy).
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy). Also known as South Dakota Electric.
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
Blockchain Interruptible Service (BCIS) Tariff	A WPSC-approved tariff applicable to prospective new Wyoming Electric blockchain customers. The tariff allows customers to negotiate rates and terms and conditions for interruptible electric utility service of 10 MW or greater that would be interconnected with Wyoming Electric's system. Agreements under the BCIS tariff must be filed with the WPSC prior to the first customer billing, be at least 2 years in duration and include specific pricing for all electricity purchased (with pricing terms subject to renegotiation every three years). BCIS customers shall not participate in the PCA to the extent of service received under the tariff.
Btu	British thermal unit
Busch Ranch I	The 29 MW wind farm near Pueblo, Colorado, jointly owned by Colorado Electric and Black Hills Electric Generation. Colorado Electric and Black Hills Electric Generation each have a 50% ownership interest in the wind farm. Black Hills Electric Generation provides its share of energy from the wind farm to Colorado Electric through a PPA, which expires in October 2037.
Busch Ranch II	The 59.4 MW wind farm near Pueblo, Colorado owned by Black Hills Electric Generation to provide wind energy to Colorado Electric through a PPA expiring in November 2044.

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CACJA Adjustment	Clean Air Clean Jobs Act Adjustment is an adjustment mechanism that allows Colorado Electric to collect from customers the capital costs related to Pueblo Airport Generation CT #6.
CFTC	United States Commodity Futures Trading Commission
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation, providing electric service in the Cheyenne, Wyoming area (doing business as Black Hills Energy). Also known as Wyoming Electric.
Cheyenne Prairie	Cheyenne Prairie Generating Station located in Cheyenne, Wyoming serves the utility customers of South Dakota Electric and Wyoming Electric. The facility includes one simple-cycle, 40 MW combustion turbine that is wholly-owned by Wyoming Electric and one combined-cycle, 100 MW unit that is jointly-owned by Wyoming Electric (42 MW) and South Dakota Electric (58 MW).
Choice Gas Program	Regulator-approved programs in Wyoming and Nebraska that allow certain utility customers to select their natural gas commodity supplier, providing the unbundling of the commodity service from the distribution delivery service.
City of Gillette	Gillette, Wyoming
Clean Energy Plan	2030 Ready Plan that establishes a roadmap and preferred resource portfolio for Colorado Electric to cost-effectively achieve the State of Colorado's requirement calling upon electric utilities to reduce GHG emissions by a minimum of 80% from 2005 levels by 2030. Based on initial modeling, the preferred resource portfolio proposes the addition of approximately 400 MW of clean energy resources (100 MW of wind, 200-250 MW of solar and 50 MW of battery storage) to Colorado Electric's system. The final mix of resources will be determined by the results of a competitive solicitation that was issued in July 2023. Colorado legislation allows electric utilities to own up to 50% of the renewable generation assets added to comply with the Clean Energy Plan.
CO_2	Carbon dioxide
Chief Operating Decision Maker (CODM)	Chief Executive Officer
Colorado Electric	Black Hills Colorado Electric, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Parent Holdings, providing electric service to customers in Colorado (doing business as Black Hills Energy).
Colorado Gas	Black Hills Colorado Gas, Inc., an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Colorado (doing business as Black Hills Energy).
Common Use System	The Common Use System is a jointly operated transmission system we participate in with Basin Electric Power Cooperative and Powder River Energy Corporation. The Common Use System provides transmission service over these utilities' combined 230-kilovolt (kV) and limited 69-kV transmission facilities within areas of southwestern South Dakota and northeastern Wyoming.
Consolidated Indebtedness to Capitalization Ratio	Any Indebtedness outstanding at such time, divided by capital at such time. Capital being consolidated net-worth (excluding non-controlling interest) plus consolidated indebtedness (including letters of credit and certain guarantees issued) as defined within the current Revolving Credit Facility.
Cooling Degree Day	A cooling degree day is equivalent to each degree that the average of the high and low temperature for a day is above 65 degrees. The warmer the climate, the greater the number of cooling degree days. Cooling degree days are used in the utility industry to measure the relative warmth of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations.
Corriedale	The 52.5 MW wind farm near Cheyenne, Wyoming, jointly owned by South Dakota Electric (32.5 MW) and Wyoming Electric (20 MW), serving as the dedicated wind energy supply to the Renewable Ready program, which is a voluntary renewable energy subscription program for large commercial, industrial and governmental customers in South Dakota and Wyoming.
CP Program	Commercial Paper Program
CPCN	Certificate of Public Convenience and Necessity
CPUC	Colorado Public Utilities Commission
CSAPR	The United States Environmental Protection Agency's Cross-State Air Pollution Rule

CT	Combustion Turbine
Cushion Gas	The portion of natural gas necessary to force saleable gas from a storage field into the transmission system and for system balancing, representing a permanent investment necessary to use storage facilities and maintain reliability.
Cybersecurity incident	An unauthorized occurrence, or a series of related unauthorized occurrences, on or conducted through a registrant’s information systems that jeopardizes the confidentiality, integrity, or availability of a registrant’s information systems or any information residing therein.
Cybersecurity threat	Any potential unauthorized occurrence on or conducted through a registrant’s information systems that may result in adverse effects on the confidentiality, integrity or availability of a registrant’s information systems or any information residing therein.
DC	Direct Current
Dividend Payout Ratio	Annual dividends paid on common stock divided by net income from continuing operations available for common stock
DRSPP	Dividend Reinvestment and Stock Purchase Plan
DSM	Demand Side Management
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu).
EBITDA	Earnings before interest, taxes, depreciation and amortization, a non-GAAP measure.
ECA	Energy Cost Adjustment is an adjustment that allows us to pass the prudently-incurred cost of fuel and purchased energy through to customers.
Economy Energy	Purchased energy that costs less than that produced with the utilities’ owned generation.
EECR	Energy Efficiency Cost Recovery is an adjustment mechanism that allows us to recover from customers the costs associated with providing energy efficiency programs.
EIA	Environmental Improvement Adjustment is an annual adjustment mechanism that allows us to recover from customers eligible investments in, and expense related to, new environmental measures.
EGU	Electric generating unit
Energy Assistance Benefit Charge	Energy Assistance Benefit Charge is a Colorado statutory-created surcharge to provide additional funding for bill assistance and weatherization for income-qualified customers. We collect these funds and remit them to a Colorado non-profit organization that assists low-income residents with utility bills, repairs, and energy efficiency upgrades.
Energy Transition	The global energy sector’s shift from fossil-based systems of energy production and consumption, including oil, natural gas and coal to renewable energy sources like wind and solar, as well as battery storage solutions.
EPA	United States Environmental Protection Agency
ESG	Environmental, Social and Governance
EV	Electric Vehicle
EWG	Exempt Wholesale Generator
FASB	Financial Accounting Standards Board
FERC	United States Department of Energy's Federal Energy Regulatory Commission
Fitch	Fitch Ratings Inc.
GAAP	Accounting principles generally accepted in the United States of America
Gas Price Risk Management Rider	Gas Price Risk Management Rider is a mechanism that is similar to GCA but designed to also provide a price floor and price ceiling.
GCA	Gas Cost Adjustment is an adjustment that allows us to pass the prudently-incurred cost of gas and certain services through to customers.
GHG	Greenhouse gases
Gillette Energy Complex	The Gillette Energy Complex located in Gillette, Wyoming includes 793 MW of coal-fired generating facilities (Neil Simpson II, Wygen I, Wygen II, Wygen III, Wyodak Plant) which are supplied by WRDC and a 40 MW gas-fired generation facility (Neil Simpson CT). We operate and own majority interests in five of the six facilities and own 20% of Wyodak Plant.

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Global Settlement	Settlement with a utility's commission where the revenue requirement is agreed upon, but the specific adjustments used by each party to arrive at the amount are not specified in public rate orders.
GWh	Gigawatt Hours
Heating Degree Day	A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the utility industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations.
HomeServe	We offer HomeServe products to our natural gas residential customers interested in purchasing additional home repair service plans.
Information systems	Electronic information resources, owned or used by the registrant, including physical or virtual infrastructure controlled by such information resources, or components thereof, organized for the collection, processing, maintenance, use, sharing, dissemination, or disposition of the registrant's information to maintain or support the registrant's operations.
Integrated Generation	Non-regulated power generation and mining businesses (Black Hills Electric Generation and WRDC) that are vertically integrated within our Electric Utilities segment.
Iowa Gas	Black Hills Iowa Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Iowa (doing business as Black Hills Energy).
IPP	Independent Power Producer
IRA	Inflation Reduction Act of 2022
IRC	Internal Revenue Code
IRP	Integrated Resource Plan
IRS	United States Internal Revenue Service
ITC	Investment Tax Credit
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Kansas (doing business as Black Hills Energy).
kV	Kilovolt
LIBOR	London Interbank Offered Rate
Mcf	Thousand cubic feet
Mcfd	Thousand cubic feet per day
MDU	Montana-Dakota Utilities Co., a subsidiary of MDU Resources Group, Inc.
MEAN	Municipal Energy Agency of Nebraska
MMBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MSHA	United States Department of Labor's Mine Safety and Health Administration
MW	Megawatts
MWh	Megawatt-hours
N/A	Not Applicable
NAAQS	National Ambient Air Quality Standards
NAV	Net Asset Value
Nebraska Gas	Black Hills Nebraska Gas, LLC, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Nebraska (doing business as Black Hills Energy).
Neil Simpson II	A mine-mouth, coal-fired power plant owned and operated by South Dakota Electric with a total capacity of 90 MW located at our Gillette Energy Complex.
NERC	North American Electric Reliability Corporation
NO_X	Nitrogen oxide

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NOL	Net Operating Loss
Northern Iowa Windpower	Northern Iowa Windpower, LLC, a 87.1 MW wind farm located near Joice, Iowa, previously owned by Black Hills Electric Generation. In March 2023, Black Hills Electric Generation completed the sale of Northern Iowa Windpower assets to a third-party.
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
OSHA	United States Department of Labor’s Occupational Safety & Health Administration
OSM	United States Department of the Interior’s Office of Surface Mining
PacifiCorp	PacifiCorp, a wholly owned subsidiary of MidAmerican Energy Holdings Company, itself an affiliate of Berkshire Hathaway.
PCA	Power Cost Adjustment is an annual adjustment mechanism that allows us to pass a portion of prudently-incurred delivered power costs, including fuel, purchased capacity and energy, and transmission costs, through to customers.
PCCA	Power Capacity Cost Adjustment is an annual adjustment that allows us to pass the prudently-incurred purchased capacity costs, incremental to costs included in base rates, through to customers.
Peak View	The 60.8 MW wind farm owned by Colorado Electric.
PHMSA	United States Department of Transportation's Pipeline and Hazardous Materials Safety Administration
PPA	Power Purchase Agreement
PSA	Power Sales Agreement
PTC	Production Tax Credit
Pueblo Airport Generation	Pueblo Airport Generating Station located in Pueblo, Colorado includes 440 MW of combined cycle gas-fired power generation plants jointly owned by Colorado Electric (240 MW) and Black Hills Colorado IPP (200 MW). Black Hills Colorado IPP owns and operates this facility. The plants commenced operation on January 1, 2012.
PUHCA 2005	Public Utility Holding Company Act of 2005
Ready	The Company’s branding platform which emphasizes that we will 1) prioritize our customers; 2) act as a thoughtful, responsible leader; 3) listen first and lead with a focus on relationships; and 4) be creative in our approach to solutions.
Ready Wyoming	A 260-mile, multi-phase transmission expansion project in Wyoming. This transmission project is expected to serve the growing needs of customers by enhancing resiliency of Wyoming Electric’s overall electric system and expanding access to power markets and renewable resources. The project is expected to help Wyoming Electric maintain top-quartile reliability and enable economic development in the Cheyenne, Wyoming region.
RESA	Renewable Energy Standard Adjustment is an incremental retail rate limited to 2% for Colorado Electric customers that provides funding for renewable energy projects and programs to comply with Colorado’s Renewable Energy Standard.
Revolving Credit Facility	Our $750 million credit facility used to fund working capital needs, letters of credit and other corporate purposes, which was amended on May 9, 2023 and will terminate on July 19, 2026. This facility includes an accordion feature that allows us to increase total commitments up to $1.0 billion with the consent of the administrative agent, the issuing agents and each bank increasing or providing a new commitment.
RMNG	Rocky Mountain Natural Gas LLC, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas transmission and wholesale services in western Colorado (doing business as Black Hills Energy).
RNG	Renewable natural gas
RTO	Regional Transmission Organization
SDPUC	South Dakota Public Utilities Commission
SEC	United States Securities and Exchange Commission
Service Guard Comfort Plan	Appliance protection plan that provides home appliance repair services through on-going monthly service agreements to residential utility customers.
SO_2	Sulfur dioxide
SOFR	Secured Overnight Financing Rate

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S&P	S&P Global Ratings, a division of S&P Global Inc.
South Dakota Electric	Black Hills Power, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation, providing electric service to customers in Montana, South Dakota and Wyoming (doing business as Black Hills Energy).
SPP	Southwest Power Pool, a regional transmission organization (RTO) that oversees the bulk electric grid and wholesale power market in the central United States.
SSIR	System Safety and Integrity Rider is a mechanism that allows us to recover the costs associated with certain pipeline safety and integrity investments, including the replacement of higher risk pipe, the improvement of the data management system, and the mitigation of other safety issues identified on our natural gas system.
System Peak Demand	Represents the highest point of retail customer usage for a single hour.
TCA	Transmission Cost Adjustment is an annual adjustment mechanism that allows us to recover from customers eligible transmission investments prior to the next rate review.
TCAM	Transmission Cost Adjustment Mechanism is a WPSC-approved tariff based on a formulaic approach that determines the recovery of Wyoming Electric's transmission costs.
TCJA	Tax Cuts and Jobs Act enacted on December 22, 2017, which reduced the U.S. federal corporate tax rate from 35% to 21%. As such, we remeasured our deferred income taxes at the 21% federal tax rate as of December 31, 2017.
Tech Services	Non-regulated product lines delivered by our Utilities that 1) provide electrical system construction services to large industrial customers of our electric utilities, and 2) serve gas transportation customers throughout its service territory by constructing and maintaining customer-owned gas infrastructure facilities, typically through one-time contracts.
TEPR	Transportation Electrification Program Rider is a CPUC-approved mechanism associated with Colorado Electric's EV program.
TFA	Transmission Facility Adjustment is an annual adjustment mechanism that allows us to recover charges for qualifying new and modified transmission facilities from customers.
Transmission Tie	South Dakota Electric owns 35% of a AC-DC-AC transmission tie that interconnects the Western and Eastern transmission grids, which are independently-operated transmission grids serving the western and eastern United States, respectively. Basin Electric Power Cooperative owns the remaining ownership percentage. This transmission tie allows us to buy and sell energy in the Eastern grid without having to isolate and physically reconnect load or generation between the two transmission grids, thus enhancing the reliability of our system. It accommodates scheduling transactions in both directions simultaneously, provides additional opportunities to sell excess generation or to make economic purchases to serve our native load and contract obligations, and enables us to take advantage of power price differentials between the two grids. The total transfer capacity of the tie is 400 MW, including 200 MW from West to East and 200 MW from East to West.
TSA	United States Department of Homeland Security's Transportation Security Administration
Utilities	Black Hills' Electric and Gas Utilities
VEBA	Voluntary Employee Benefit Association
VIE	Variable Interest Entity
WEIS	Western Energy Imbalance Service
Wind Capacity Factor	Measures the amount of electricity a wind turbine produces in a given time period relative to its maximum potential
Winter Storm Uri	February 2021 winter weather event that caused extreme cold temperatures in the central United States and led to unprecedented fluctuations in customer demand and market pricing for natural gas and energy.
Working Capacity	Total gas storage capacity minus cushion gas
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a coal mine which is a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings, providing coal supply primarily to five on-site, mine-mouth generating facilities at our Gillette Energy Complex (doing business as Black Hills Energy).
Wygen I	A mine-mouth, coal-fired generating facility with a total capacity of 90 MW located at our Gillette Energy Complex. Black Hills Wyoming owns 76.5% of the facility and Municipal Energy Agency of Nebraska (MEAN) owns the remaining 23.5%.

Wygen II	A mine-mouth, coal-fired power plant owned by Wyoming Electric with a total capacity of 95 MW located at our Gillette Energy Complex.
Wygen III	A mine-mouth, coal-fired power plant operated by South Dakota Electric with a total capacity of 116 MW located at our Gillette Energy Complex. South Dakota Electric owns 52% of the power plant, MDU owns 25% and the City of Gillette owns the remaining 23%.
Wyodak Plant	The 402.3 MW mine-mouth, coal-fired generating facility located at our Gillette Energy Complex, jointly owned by PacifiCorp (80%) and South Dakota Electric (20%). WRDC supplies all of the fuel for the facility.
Wyoming Electric	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation, providing electric service to customers in the Cheyenne, Wyoming area (doing business as Black Hills Energy).
Wyoming Gas	Black Hills Wyoming Gas, LLC, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Wyoming (doing business as Black Hills Energy).
Wyoming Integrity Rider	The Wyoming Integrity Rider (WIR) is a WPSC-approved tariff that allows Wyoming Gas to recover costs from customers associated with ongoing infrastructure replacement, gas meter and yard line replacement projects driven by federal regulation.

WEBSITE ACCESS TO REPORTS

The reports we file with the SEC are available free of charge at our website www.blackhillscorp.com as soon as reasonably practicable after they are filed. In addition, the charters of our Audit, Governance and Compensation Committees are located on our website along with our Code of Business Conduct, Code of Ethics for our Chief Executive Officer and Senior Finance Officers, Corporate Governance Guidelines of the Board of Directors and Policy for Director Independence. The information contained on our website is not part of this document.

FORWARD-LOOKING INFORMATION

This Form 10-K contains forward-looking statements as defined by the SEC. Forward-looking statements are all statements other than statements of historical fact, including, without limitation, those statements that are identified by the words “anticipates,” “estimates,” “expects,” “intends,” “plans,” “predicts” and similar expressions and include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions and other statements that are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature, including statements contained within Item 7 - Management’s Discussion & Analysis of Financial Condition and Results of Operations.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. The Company’s expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including, without limitation, management’s examination of historical operating trends, data contained in the Company’s records and other data available from third parties. Nonetheless, the Company’s expectations, beliefs or projections may not be achieved or accomplished.

Any forward-looking statement contained in this document speaks only as of the date on which the statement is made and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, such as adverse macroeconomic conditions, global pandemics or severe weather events, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company’s business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements in this Annual Report on Form 10-K, including statements contained within Item 1A - Risk Factors.

PART I

ITEM 1. BUSINESS

History and Organization

Black Hills Corporation, a South Dakota corporation (together with its subsidiaries, referred to herein as the "Company," "we," "us" or "our"), is a customer-focused, growth-oriented utility company headquartered in Rapid City, South Dakota (incorporated in South Dakota in 1941).

We operate our business in the United States, reporting our operating results through our Electric Utilities and Gas Utilities segments. Certain unallocated corporate expenses that support our operating segments are presented as Corporate and Other.

Our Electric Utilities segment generates, transmits and distributes electricity to approximately 222,000 electric utility customers in Colorado, Montana, South Dakota and Wyoming. Our Electric Utilities own 1,394 MW of generation and 9,106 miles of electric transmission and distribution lines.

Our Gas Utilities segment serves approximately 1,116,000 natural gas utility customers in Arkansas, Colorado, Iowa, Kansas, Nebraska, and Wyoming. Our Gas Utilities own and operate 4,663 miles of intrastate gas transmission pipelines and 42,514 miles of gas distribution mains and service lines, seven natural gas storage sites, more than 50,000 horsepower of compression and 516 miles of gathering lines.

Electric Utilities

We conduct electric utility operations through our Colorado, South Dakota and Wyoming subsidiaries. Our Electric Utilities generate, transmit and distribute electricity to our retail customers. Our electric generating facilities and power purchase agreements provide for the supply of electricity principally to our retail customers. We also sell excess power to other utilities and marketing companies, including our affiliates. Additionally, we provide non-regulated services to our retail customers under the Service Guard Comfort Plan and Tech Services.

We also own and operate non-regulated power generation and mining assets that are vertically integrated into and primarily support our Electric Utilities. All of these operations are located at our electric generating complexes and are physically integrated into our Electric Utilities' operations.

	As of December 31,		
Retail Customers	**2023**	**2022**	**2021**
Residential	190,776	188,921	186,852
Commercial	30,491	30,404	30,326
Industrial	84	82	81
Other	989	1,024	1,010
Total Electric Retail Customers at End of Year	222,340	220,431	218,269

	As of December 31,		
Retail Customers	**2023**	**2022**	**2021**
Colorado Electric	100,907	100,573	99,709
South Dakota Electric	76,479	75,169	74,509
Wyoming Electric	44,954	44,689	44,051
Total Electric Retail Customers at End of Year	222,340	220,431	218,269

Capacity and Demand. System Peak Demand for the Electric Utilities' retail customers for each of the last three years are listed below:

	System Peak Demand (in MW)					
	2023 [(a)]		2022		2021	
	Summer	Winter	Summer	Winter	Summer	Winter
Colorado Electric	411	297	410	334	407	279
South Dakota Electric	378	289	403	355	397	299
Wyoming Electric	312	301	294	281	274	246

(a) In 2023, Wyoming Electric set new summer and winter peak loads. See recent peak discussion in the Recent Developments section of Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 in this Annual Report on Form 10-K for additional information.

As of December 31, 2023, our Electric Utilities' ownership interests in electric generating plants were as follows:

Unit	Fuel Type	Location	Ownership Interest % [(d)]	Owned Nameplate Capacity (MW)	In Service Date
Colorado Electric:					
Busch Ranch I [(a)]	Wind	Pueblo, Colorado	50%	14.5	2012
Peak View [(b) (c)]	Wind	Pueblo, Colorado	100%	60.8	2016
Pueblo Airport Generation #1-2	Natural Gas	Pueblo, Colorado	100%	200.0	2011
Pueblo Airport Generation CT #6	Natural Gas	Pueblo, Colorado	100%	40.0	2016
AIP Diesel	Diesel Oil	Pueblo, Colorado	100%	10.0	2001
Diesel #1 and #3-5	Diesel Oil	Pueblo, Colorado	100%	8.0	1964
Diesel #1-5	Diesel Oil	Rocky Ford, Colorado	100%	10.0	1964
South Dakota Electric:					
Cheyenne Prairie	Natural Gas	Cheyenne, Wyoming	58%	58.0	2014
Corriedale [(c)]	Wind	Cheyenne, Wyoming	62%	32.5	2020
Wygen III	Coal	Gillette, Wyoming	52%	60.3	2010
Neil Simpson II	Coal	Gillette, Wyoming	100%	90.0	1995
Wyodak Plant	Coal	Gillette, Wyoming	20%	80.5	1978
Neil Simpson CT	Natural Gas	Gillette, Wyoming	100%	40.0	2000
Lange CT	Natural Gas	Rapid City, South Dakota	100%	40.0	2002
Ben French Diesel #1-5	Diesel Oil	Rapid City, South Dakota	100%	10.0	1965
Ben French CTs #1-4	Natural Gas/Diesel Oil	Rapid City, South Dakota	100%	100.0	1977-1979
Wyoming Electric:					
Cheyenne Prairie	Natural Gas	Cheyenne, Wyoming	42%	42.0	2014
Cheyenne Prairie CT	Natural Gas	Cheyenne, Wyoming	100%	40.0	2014
Corriedale [(c)]	Wind	Cheyenne, Wyoming	38%	20.0	2020
Wygen II	Coal	Gillette, Wyoming	100%	95.0	2008
Integrated Generation:					
Wygen I	Coal	Gillette, Wyoming	76.5%	68.9	2003
Pueblo Airport Generation #4-5	Natural Gas	Pueblo, Colorado	50.1% [(e)]	200.0	2012
Busch Ranch I [(a)]	Wind	Pueblo, Colorado	50%	14.5	2012
Busch Ranch II [(c)]	Wind	Pueblo, Colorado	100%	59.4	2019
Total MW Capacity				1,394.4	

(a) In 2013, Busch Ranch I was awarded a one-time cash grant in lieu of ITCs under the Section 1603 program created under the American Recovery and Reinvestment Act.
(b) The PTCs for Peak View flow back to customers through a rider mechanism as a reduction to Colorado Electric's margins.
(c) This facility qualifies for PTCs at $28/MWh under IRC 45 during the 10-year period beginning on the date the facility was originally placed in service.
(d) Jointly owned facilities are discussed in Note 6 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.
(e) In 2016, Black Hills Electric Generation sold a 49.9% non-controlling interest in Black Hills Colorado IPP to a third party. See Note 12 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

Our Electric Utilities' power supply by resource as a percent of the total power supply for our energy needs for the years ended December 31 was as follows:

Power Supply	2023	2022	2021
Coal	35.0 %	35.1 %	34.2 %
Natural Gas	26.4 %	18.8 %	24.4 %
Wind [(a)]	8.9 %	11.4 %	11.3 %
Total Generated [(b)]	70.3 %	65.3 %	69.9 %
Coal, Natural Gas, Diesel Oil and Other Market Purchases	24.1 %	29.6 %	25.1 %
Wind and Solar Purchases	5.6 %	5.1 %	5.0 %
Total Purchased	29.7 %	34.7 %	30.1 %
Total	100.0 %	100.0 %	100.0 %

(a) Wind generation decreased due to the sale of Northern Iowa Windpower assets in March 2023.
(b) The diesel oil-fueled generating units are generally used as supplemental peaking units. Power generated from these units, as a percentage of total power supply, was 0.0% for each of the years presented.

Our Electric Utilities' weighted average cost of fuel utilized to generate electricity and the average price paid for purchased power (excluding contracted capacity) per MWh for the years ended December 31 were as follows:

Fuel and Purchased Power (dollars per MWh)	2023	2022	2021
Coal	$ 13.40	$ 12.76	$ 11.55
Natural Gas	20.20	37.09	33.65
Total Generated Weighted Average Fuel Cost	14.27	17.57	17.40
Coal, Natural Gas, Diesel Oil and Other Market Purchases	55.61	66.35	64.85
Wind and Solar Purchases	34.99	33.78	34.69
Total Purchased Power Weighted Average Cost	51.68	61.56	59.84
Total Weighted Average Fuel and Purchased Power Cost	$ 25.39	$ 32.82	$ 30.17

Purchased Power. We have executed various PPAs to support our Electric Utilities' capacity and energy needs beyond our regulated power plants' generation, which include long-term related party agreements with our non-regulated power generation businesses. See additional information in Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Coal Mining. We own and operate a single coal mine through our WRDC subsidiary which is reported within our Electric Utilities segment. We surface mine, process and sell low-sulfur sub-bituminous coal at our mine located immediately adjacent to our Gillette Energy Complex in the Powder River Basin in northeastern Wyoming, where our five coal-fired power plants are located. We produced approximately 3.7 million tons of coal in 2023.

The mine provides low-sulfur coal directly to these five power plants via a conveyor belt system, minimizing transportation costs. The fuel can be delivered to our adjacent power plants at very cost competitive prices (i.e., $1.14 per MMBtu for year ended December 31, 2023) when compared to alternatives. Nearly all of the mine's production is sold to our on-site generation facilities under long-term supply contracts.

As of December 31, 2023, we estimated our recoverable reserves to be approximately 179 million tons, based on a life-of-mine engineering study utilizing currently available drilling data and geological information prepared by internal engineering analyses. The recoverable reserve life is equal to approximately 48 years at the current production levels.

Transmission and Distribution. Through our Electric Utilities, we own electric transmission and distribution systems composed of high voltage lines (greater than 69 kV) and low voltage lines (69 kV or less). We also jointly operate an electric transmission system, referred to as the Common Use System, with Basin Electric Power Cooperative and Powder River Energy Corporation. Each participant in the Common Use System individually owns assets that are operated together for a single system. The Common Use System also provides transmission service to our Transmission Tie. South Dakota Electric owns 35% of the Transmission Tie. The Transmission Tie is further discussed in Note 6 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

At December 31, 2023, our Electric Utilities owned the electric transmission and distribution lines shown below:

Utility	State	Transmission [(a)] (in Line Miles)	Distribution (in Line Miles)
Colorado Electric	Colorado	599	3,213
South Dakota Electric [(b)]	South Dakota, Wyoming	1,232	2,616
Wyoming Electric	Wyoming	86	1,360
		1,917	7,189

(a) Electric transmission line miles include voltages of 69 kV and above.
(b) South Dakota Electric transmission line miles include 43 miles within the Common Use System.

Material transmission services agreements are included in our disclosures in Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Seasonal Variations of Business. Our Electric Utilities are seasonal businesses and weather patterns may impact their operating results. Demand for electricity is sensitive to seasonal cooling, heating and industrial load requirements, as well as market price. In particular, cooling demand is often greater in the summer and heating demand is often greater in the winter.

Competition. We generally have limited competition for the retail generation and distribution of electricity in our service areas. Various legislative or regulatory restructuring and competitive initiatives have been discussed in several of the states in which our utilities operate. These initiatives would be aimed at increasing competition or providing for distributed generation. To date, these initiatives have not had a material impact on our utilities. In Colorado, our electric utility is subject to rules which may require competitive bidding for generation supply. Because of these rules, we face competition from other utilities and non-affiliated IPPs for the right to supply electric energy and capacity for Colorado Electric when resource plans require additional resources. Additionally, electrification initiatives in our service territories could increase demand for electricity and increase customer growth.

The independent power industry consists of many strong and capable competitors, some of which may have more extensive operations or greater financial resources than we possess. With respect to the merchant power sector, FERC has taken steps to increase access to the national transmission grid by utility and non-utility purchasers and sellers of electricity to foster competition within the wholesale electricity markets. Our non-regulated power generation businesses could face greater competition if utilities are permitted to robustly invest in power generation assets. Conversely, state regulations requiring utilities to competitively bid generation resources may provide opportunity for IPPs in some regions. To date, these initiatives have not had a material impact on our non-regulated power generation businesses.

Our mining business strategy is to sell nearly all of our production to on-site generation facilities under long-term supply contracts. Historically, any off-site sales have been to consumers within close proximity to WRDC. Coal competes with other energy sources, such as natural gas, nuclear, wind, solar and hydropower. Costs and other factors relating to these alternative fuels, such as safety, environmental and availability considerations affect the overall demand for coal as a fuel.

Operating Statistics. See a summary of key operating statistics in the Electric Utilities segment operating results within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K.

Gas Utilities

We conduct natural gas utility operations through our Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming subsidiaries. Our Gas Utilities transport and distribute natural gas through our distribution network to our retail customers. Additionally, we sell contractual pipeline capacity and gas commodities to other utilities and marketing companies, including our affiliates, on an as-available basis.

We also provide non-regulated services to our regulated customers. Black Hills Energy Services provides natural gas supply to approximately 53,000 retail distribution customers under the Choice Gas Program in Nebraska and Wyoming. Additionally, we provide services under the Service Guard Comfort Plan, Tech Services and HomeServe.

	As of December 31,		
Retail Customers	**2023**	**2022**	**2021**
Residential	871,930	864,038	853,908
Commercial	84,917	85,203	84,234
Industrial	2,179	2,189	2,158
Transportation	157,367	155,685	153,929
Total Natural Gas Retail Customers at End of Year	1,116,393	1,107,115	1,094,229

	As of December 31,		
Retail Customers	**2023**	**2022**	**2021**
Arkansas Gas	186,216	183,270	180,216
Colorado Gas	211,155	208,060	202,747
Iowa Gas	163,281	162,801	161,905
Kansas Gas	119,407	118,599	117,862
Nebraska Gas	302,167	301,007	298,832
Wyoming Gas	134,167	133,378	132,667
Total Natural Gas Retail Customers at End of Year	1,116,393	1,107,115	1,094,229

We procure natural gas for our distribution customers from a diverse mix of producers, processors and marketers and generally use hedging, physical fixed-price purchases and market-based price purchases to achieve dollar-cost averaging within our natural gas portfolio. The majority of our procured natural gas is transported in interstate pipelines under firm transportation service agreements.

In addition to company-owned regulated underground natural gas storage assets in Arkansas, Colorado and Wyoming, we also contract with third-party transportation providers for natural gas storage service to provide gas supply during the winter heating season and to meet peak day customer demand for natural gas.

The following table summarizes certain information regarding our company-owned regulated underground gas storage facilities as of December 31, 2023:

	Working Capacity (Mcf)	Cushion Gas (Mcf)	Total Capacity (Mcf)	Maximum Daily Withdrawal Capability (Mcfd)
Arkansas Gas	8,442,700	13,149,040	21,591,740	196,000
Colorado Gas	2,360,895	6,165,315	8,526,210	30,000
Wyoming Gas	5,733,900	17,545,600	23,279,500	36,000
Total	16,537,495	36,859,955	53,397,450	262,000

The following table summarizes certain information regarding our system infrastructure as of December 31, 2023:

	Intrastate Gas Transmission Pipelines (in line miles)	Gas Distribution Mains (in line miles)	Gas Distribution Service Lines (in line miles)
Arkansas Gas	875	5,197	1,380
Colorado Gas	694	7,188	1,861
Iowa Gas	173	2,890	2,765
Kansas Gas	339	3,026	1,400
Nebraska Gas	1,315	8,611	2,845
Wyoming Gas	1,267	3,625	1,726
Total	4,663	30,537	11,977

Seasonal Variations of Business. Our Gas Utilities are seasonal businesses and weather patterns may impact their operating results. Demand for natural gas is sensitive to seasonal heating and industrial load requirements, as well as market price. In particular, demand is often greater in the winter months for heating. Natural gas is used primarily for residential and commercial heating, and demand for this product can depend heavily upon weather throughout our service territories. As a result, a significant amount of natural gas revenue is normally recognized in the heating season consisting of the first and fourth quarters. Demand for natural gas can also be impacted by summer temperatures and precipitation, which can affect demand for irrigation.

Competition. We generally have limited competition for the retail distribution of natural gas in our service areas. Various restructuring and competitive initiatives have been discussed in several of the states in which our utilities operate. These initiatives are aimed at increasing competition. Additionally, electrification initiatives in our service territories could negatively impact demand for natural gas and decrease future growth. To date, these initiatives have not had a material impact on our utilities. Although we face competition from independent marketers for the sale of natural gas to our industrial and commercial customers, in instances where independent marketers displace us as the seller of natural gas, we still collect fees for transporting the gas through our distribution network.

Operating statistics. See a summary of key operating statistics in the Gas Utilities segment operating results within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K.

Utility Regulation Characteristics

Our Utilities are subject to regulation by a number of federal, state and other organizations, including, but not limited to, the following:

- State public utility commissions, which have jurisdiction over services and facilities, rates and charges, accounting, valuation of property, depreciation rates and various other matters;
- the FERC, which oversees the acquisition and disposition of generation, transmission and other facilities, transmission of electricity and natural gas in interstate commerce, proposals to build and operate interstate natural gas pipelines and storage facilities, and wholesale purchases and sales of electric energy, among other things;
- the NERC, which, through its regional entities, establishes and enforces mandatory reliability standards, subject to approval by the FERC, to ensure the reliability of the U.S. electric transmission and generation system and to prevent major system blackouts;
- the EPA, which has the responsibility to maintain and enforce national standards under a variety of environmental laws, in some cases delegating authority to state agencies. The EPA also works with industries and all levels of government, including federal and state governments, in a wide variety of voluntary pollution prevention programs and energy conservation efforts;
- the TSA, which regulates certain activities related to the safety and security of natural gas pipelines. In May and July 2021 the TSA issued security directives that included several new cybersecurity requirements for critical pipeline owners and operators; and
- the PHMSA, which is responsible for administering the federal regulatory program to help ensure the safe transportation of natural gas, petroleum and other hazardous materials by pipelines, including pipelines associated with natural gas storage, and develops regulations and other approaches to risk management to help ensure safety in design, construction, testing, operation, maintenance and emergency response of pipeline facilities.

Rates and Regulation

Our Utilities are subject to the jurisdiction of the public utility commissions in the states where they operate and the FERC for certain assets and transactions. These commissions oversee services and facilities, rates and charges, accounting, valuation of property, depreciation rates and various other matters. Rate decisions are influenced by many factors, including the cost of providing service, capital expenditures, the prudence of costs we incur, views concerning appropriate rates of return, general economic conditions and the political environment. Certain commissions also have jurisdiction over the issuance of debt or securities and the creation of liens on property located in their states to secure bonds or other securities.

The regulatory provisions for recovering the costs of service vary by jurisdiction. Our Utilities have cost recovery mechanisms that allow us to pass the prudently-incurred cost of natural gas, fuel and purchased power to customers. These mechanisms allow the utility operating in that state to collect or refund the difference between the cost of commodities and certain services embedded in our base rates and the actual cost of the commodities and certain services without filing a general rate review. In addition, some jurisdictions allow us to recover certain costs or earn a return on capital investments placed in service between base rate reviews through approved rider tariffs, such as energy efficiency plan costs and system safety and integrity investments. These tariffs allow the utility a return on the investment.

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Electric Utilities

The following table provides regulatory information for each of our Electric Utilities:

Subsidiary	Jurisdiction	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Authorized Capital Structure Debt/Equity	Authorized Rate Base (in millions)	Effective Date	Additional Regulatory Mechanisms	Percentage of Power Marketing Profit Shared with Customers
Colorado Electric	CO	9.37%	7.43%	48%/52%	$653.7 [(a)]	1/2017	ECA, TCA, PCCA, EECR/DSM, RESA, TEPR, Energy Assistance Benefit Charge	90%
	CO	9.37%	6.02%	67%/33%	$57.9	1/2017	CACJA Adjustment Rider	N/A
	FERC	9.80%	6.45%	53%/47%	(a)	9/2022	FERC Transmission Tariff	N/A
South Dakota Electric	WY	9.90%	8.13%	47%/53%	$46.8	10/2014	ECA	65%
	SD	Global Settlement	7.76%	Global Settlement	$543.9	10/2014	ECA, TFA, EIA	70%
	FERC	10.80%	8.76%	43%/57%	$197.7 [(b)]	2/2009	FERC Transmission Tariff	N/A
Wyoming Electric [(c)]	WY	9.75%	7.48%	48%/52%	$551.2 [(a)]	3/2023	PCA, EECR/DSM, Rate Base Recovery on Acquisition Adjustment, TCAM	N/A
	FERC	9.90%	8.77%	44%/56%	(a)	1/2019	FERC Transmission Tariff	N/A

(a) For both Wyoming Electric and Colorado Electric retail customers, transmission investments are recovered through retail rates rather than FERC Transmission Tariffs. Transmission investments are recovered from wholesale transmission customers under the FERC Formula Transmission rate. The rate base associated with FERC assets is not displayed separate from that collected through the state recovery mechanisms, to avoid double counting. The rate base amounts for Colorado Electric and Wyoming Electric include rate base recovered through base rates and the authorized regulatory mechanisms.

(b) Includes $180.6 million in 2023 rate base for the 2023 Projected Common Use System formula rate that is updated annually and $17.1 million in rate base for the Transmission Tie that is based on the approved stated rate from 2005.

(c) For additional information regarding recent rate review updates, see Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

The following table summarizes the mechanisms we have in place for each of our Electric Utilities:

	Cost Recovery Mechanisms						
Electric Utility Jurisdiction	Environmental Cost	EECR/DSM	Transmission Expense	Fuel Cost	Transmission Capital	Purchased Power	RESA
Colorado Electric [(a)]		☑	☑	☑	☑	☑	☑
Colorado Electric (FERC) [(a)]					☑		
South Dakota Electric (SD) [(b)]			☑	☑		☑	
South Dakota Electric (WY) [(c)]		☑	☑	☑		☑	
South Dakota Electric (FERC)					☑		
Wyoming Electric [(a)]		☑	☑	☑	☑	☑	
Wyoming Electric (FERC) [(a)]					☑		

(a) For both Wyoming Electric and Colorado Electric retail customers, transmission investments are recovered through retail rates rather than FERC Transmission Tariffs. Transmission investments are recovered from wholesale transmission customers under the FERC Formula Transmission rate.

(b) South Dakota Electric's EIA and TFA tariffs were suspended for a six-year moratorium period effective July 1, 2017. On January 7, 2020, South Dakota Electric received approval from the SDPUC to extend the 6-year moratorium period by an additional 3 years whereby these recovery mechanisms will not be effective prior to July 1, 2026.

(c) South Dakota Electric has WPSC authorization to accumulate certain energy efficiency costs in a regulatory asset with determination of recovery to be made in the next rate review.

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Gas Utilities

The following table provides regulatory information for each of our Gas Utilities:

Subsidiary	Jurisdiction	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Authorized Capital Structure Debt/Equity	Authorized Rate Base (in millions)	Effective Date	Additional Regulatory Mechanisms
Arkansas Gas [(a)]	AR	9.60%	6.20% [(b)]	55%/45%	$674.6 [(c)]	10/2022	GCA, Safety and Integrity Rider, EECR, Weather Normalization Adjustment, Billing Determinant Adjustment
Colorado Gas [(a)]	CO	9.20%	6.56%	50%/50%	$303.2	1/2022	GCA, SSIR, DSM, Gas Price Risk Management Rider, Energy Assistance Benefit Charge
RMNG [(a)]	CO	9.50%-9.70%	6.93%	48%-50%/ 50%-52%	$209.3	7/2023	Liquids/Off-system/Market Center Services Revenue Sharing
Iowa Gas	IA	9.60%	6.75%	50%/50%	$300.9	1/2022	GCA, EECR, System Safety and Maintenance Adjustment Rider, Gas Supply Optimization revenue sharing
Kansas Gas	KS	Global Settlement	Global Settlement	Global Settlement	Global Settlement	1/2022	GCA, Weather Normalization Tariff, Gas System Reliability Surcharge, Ad Valorem Tax Surcharge, Cost of Bad Debt Collected through GCA, Pension Levelized Adjustment, Tax Adjustment Rider, Gas Supply Optimization revenue sharing
Nebraska Gas [(d)]	NE	9.50%	6.71%	50%/50%	$504.2 [(e)]	3/2021	GCA, Cost of Bad Debt Collected through GCA, Infrastructure System Replacement Cost Recovery Surcharge, Choice Gas Program, SSIR, Bad Debt expense recovered through Choice Supplier Fee, Line Locate Surcharge, HEAT Program
Wyoming Gas [(a)(d)]	WY	9.85%	7.33%	49%/51%	$450.8	1/2024	GCA, EECR, Rate Base Recovery on Acquisition Adjustment, Wyoming Integrity Rider, Choice Gas Program

(a) Colorado Gas regulatory information presented above does not reflect the recent settlement agreement which is subject to CPUC approval. For additional information regarding recent rate review updates, see Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.
(b) Arkansas Gas return on rate base is adjusted to remove certain liabilities from rate review capital structure for comparison with other subsidiaries.
(c) Arkansas Gas rate base is adjusted to include certain liabilities for comparison with other subsidiaries.
(d) The Choice Gas Program mechanisms are applicable to only a portion of Nebraska Gas and Wyoming Gas customers.
(e) Excludes amounts to serve non-jurisdictional and agriculture customers.

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The following table summarizes the mechanisms we have in place for each of our Gas Utilities:

Gas Utility Jurisdiction	Cost Recovery Mechanisms						
	EECR/DSM	Integrity Additions	Bad Debt	Weather Normal	Pension Recovery	Gas Cost [(a)]	Revenue Decoupling
Arkansas Gas	☑	☑		☑		☑	☑
Colorado Gas	☑	☑				☑	
RMNG							
Iowa Gas	☑	☑				☑	
Kansas Gas		☑	☑	☑	☑	☑	
Nebraska Gas		☑	☑			☑	
Wyoming Gas	☑	☑				☑	

(a) All of our Gas Utilities, except where the Choice Gas Program is the only option, have GCAs that allow us to pass the prudently-incurred cost of gas and certain services through to the customer between rate reviews.

Recent Tariff Filings

See Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for information regarding current regulatory activity.

FERC

The Federal Power Act gives FERC exclusive rate-making jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Pursuant to the Federal Power Act, all public utilities subject to FERC's jurisdiction must maintain tariffs and rate schedules on file with FERC that govern the rates, and terms and conditions for the provision of FERC-jurisdictional wholesale power and transmission services. Public utilities are also subject to accounting, record-keeping and reporting requirements administered by FERC. FERC also places certain limitations on transactions between public utilities and their affiliates. Our electric utility subsidiaries provide FERC-jurisdictional services subject to FERC's oversight.

Our Electric Utilities entities are authorized by FERC to make wholesale sales of electric capacity and energy at market-based rates under tariffs on file with FERC. As a condition of their market-based rate authority, Electric Quarterly Reports are filed with FERC. Our Electric Utilities own and operate FERC-jurisdictional interstate transmission facilities and provide open access transmission service under tariffs on file with FERC. Our Electric Utilities are subject to routine audit by FERC with respect to their compliance with FERC's regulations.

PUHCA 2005 provides FERC authority with respect to the books and records of a utility holding company. As a utility holding company whose assets consist primarily of investments in our subsidiaries, including subsidiaries that are public utilities and also a centralized service company subsidiary, BHSC, we are subject to FERC's authority under PUHCA 2005.

PUHCA 2005 reiterated the definition and benefits of EWG status. Under PUHCA 2005, an EWG is an entity or generator engaged, directly or indirectly through one or more affiliates, exclusively in the business of owning, operating or both owning and operating all or part of one or more eligible facilities and selling electric energy at wholesale. Though EWGs are public utilities within the definition set forth in the Federal Power Act and are subject to FERC regulation of rates and charges, they are exempt from other FERC requirements. Through its subsidiaries, Black Hills Corporation is affiliated with two EWGs, Wygen I and Pueblo Airport Generation (facilities #4-5). Both of these EWGs have been granted market-based rate authority.

NERC

The Energy Policy Act of 2005 included provisions to create an Electric Reliability Organization, which is required to promulgate mandatory reliability standards governing the operation of the bulk power system in the U.S. FERC certified NERC as the Electric Reliability Organization and also issued an initial order approving many reliability standards that went into effect in 2007. Entities that violate standards can be subject to fines and can also be assessed non-monetary penalties, depending upon the nature and severity of the violation.

Pipeline Security

In May and July 2021, the TSA issued security directives in response to a ransomware attack on the Colonial Pipeline that occurred earlier in 2021 that included several new cybersecurity requirements for critical pipeline owners and operators. Among these requirements is the implementation of specific mitigation measures to protect against ransomware attacks and other known threats to information and operational technology systems; development and implementation of a cybersecurity contingency and recovery plan; and performance of a cybersecurity architecture design review. Compliance with these measures has not had a material impact on our operations. We continue to evaluate the potential effect of these directives on our operations and facilities and will continue to monitor for any clarifications or amendments to these directives.

Gas Pipeline and Storage Integrity and Safety

We are subject to regulation by PHMSA, which requires the following for certain gas distribution and transmission pipelines and underground storage facilities: inspection and maintenance plans; integrity management programs, including the determination of pipeline integrity risks and periodic assessments on certain pipeline segments; an operator qualification program, which includes certain trainings; a public awareness program that provides certain information; and a control room management plan. If we fail to comply with applicable statutes and the PHMSA Office of Pipeline Safety's rules and related regulations and orders, we could be subject to significant penalties and fines.

Environmental Matters

We have clean energy goals to reduce GHG emissions that are based on prudent and proven solutions while minimizing cost impacts to and ensuring safety of our customers. See more information in Key Elements of our Business Strategy within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K.

We are subject to significant state and federal environmental regulations that encourage the use of clean energy technologies and regulate emissions of GHGs. We have undertaken initiatives to meet current requirements and to prepare for anticipated future regulations, reduce GHG emissions, and respond to state renewable and energy efficiency goals. Compliance with future environmental regulations could result in substantial cost.

In July of 2019, the EPA adopted the Affordable Clean Energy rule, which requires states to develop plans by 2022 for GHG reductions from coal-fired power plants. On May 23, 2023, the EPA proposed to repeal the Affordable Clean Energy rule and at the same time issued a replacement rule to establish emissions limits for GHG emissions from existing coal-fired and oil/gas-fired electric power generating boilers. The EPA also proposed GHG emission limits for existing stationary combustion turbines. The proposed emissions limitations are based upon the application of carbon capture controls or the use of hydrogen fuel beginning in 2030. The EPA is expected to issue a final rule in the first half of 2024. We will continue to monitor any related guidelines and rulemakings issued by the EPA or state regulatory authorities.

In February 2022, the EPA proposed the Good Neighbor Rule Provisions, which are part of the CSAPR framework and is intended to address ozone transport for the 2015 ozone NAAQS. The proposed rule included the state of Wyoming and imposed a NOx emissions trading program on fossil fueled electricity generating plants within the state. The EPA's consideration of revised NOx emissions inventories and revised ozone modeling resulted in Wyoming's exclusion from the final Good Neighbor Rule published on June 5, 2023. In a subsequent action published on August 14, 2023, the EPA approved Wyoming's State Implementation Plan submission addressing interstate transport for the 2015 8-hour ozone NAAQS, and Wyoming sources will not be subject to the CSAPR.

Environmental risk changes constantly with the implementation of new or modified regulations, changing stakeholder interests and needs, and through the introduction of innovative work practices and technologies. We continually assess risk and develop mitigation strategies to manage and ensure compliance across the enterprise successfully and responsibly. For additional information on environmental matters, see Item 1A and Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

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Human Capital Resources

Overview

We are committed to retaining, attracting and cultivating a talented, engaged and thriving team. By making our people and culture a strategic priority, our employees are engaged and empowered to contribute to the success of our business.

Our Team	As of December 31, 2023	As of December 31, 2022
Total employees	2,874	2,982
Women in executive leadership positions [(a)]	29%	33%
Gender diversity (women as a % of total employees)	24%	25%
Represented by a union	25%	25%
Military veterans	10%	11%
Ethnic diversity (non-white employees as a % of total)	15%	14%

	For the year ended December 31, 2023	For the year ended December 31, 2022
Number of external hires	293	487
External hires gender diversity (as a % of total external hires)	27%	30%
External hires ethnic diversity (as a % of total external hires)	24%	23%
Turnover rate [(b)]	12%	13%
Retirement rate	3%	3%

(a) Executive leadership positions are defined as positions with Vice President, Senior Vice President or Chief in their title.
(b) Includes voluntary and involuntary separations but excludes internships.

Total Employees

	Number of Employees As of December 31, 2023
Electric Utilities	425
Gas Utilities	1,198
Corporate and Other	1,251
Total	2,874

At December 31, 2023, approximately 18% of our total employees and 20% of our Electric and Gas Utilities employees were eligible for retirement (age 55 with at least 5 years of service).

Collective Bargaining Agreements

At December 31, 2023, certain employees of our Electric Utilities and Gas Utilities were covered by the collective bargaining agreements as shown in the table below. We have not experienced any labor stoppages in decades.

Utility	Number of Employees	Union Affiliation	Expiration Date of Collective Bargaining Agreement
Colorado Electric	108	IBEW Local 667	April 15, 2027
South Dakota Electric	122	IBEW Local 1250	March 31, 2027
Wyoming Electric	29	IBEW Local 111	June 30, 2024
Total Electric Utilities	**259**		
Iowa Gas	129	IBEW Local 204	January 31, 2026
Kansas Gas	15	Communications Workers of America, AFL-CIO Local 6407	December 31, 2024
Nebraska Gas	92	IBEW Local 244	March 13, 2025
Nebraska Gas	134	CWA Local 7476	October 30, 2026
Wyoming Gas	16	IBEW Local 111	June 30, 2024
Wyoming Gas	80	CWA Local 7476	October 30, 2026
Total Gas Utilities	**466**		
Total	**725**		

Diversity, Equity & Inclusion

We believe the benefits of diversity, equity and inclusion can be powerful, and we are committed to building a workforce whose diversity is representative of the communities we serve. Our recruiting strategies support our efforts to attract qualified individuals with targeted efforts to reach underrepresented talent. Our internship program and our partnerships and participation in outreach programs with local schools and colleges attract students to careers in the energy industry. Our commitment to equitable and inclusive hiring practices, including diverse candidate slates and interview panels and pay equity reviews, further supports our vision of retaining, attracting and cultivating an engaged and thriving team driven by improving life with energy. We continuously evaluate our recruitment strategies to determine their effectiveness to attract and build a talented, diverse workforce. Workforce diversity trends, which include new hires, promotions and turnover, are monitored at regular intervals throughout the year.

Development and Retention

Developing and retaining talent is critical to our continued success. Our development and retention efforts include internal and external skills training, career development programs, and competitive compensation. Our compensation programs are designed to be strategically aligned, externally competitive, internally equitable, personally motivating, cost effective and legally compliant. We monitor employee engagement through bi-annual engagement surveys and quarterly pulse surveys. Every leader is responsible for creating and implementing an action plan based on their team's engagement survey results. Our career development programs include management onboarding, leadership development programs, mentoring programs, individual development assessments, stretch opportunities, talent sharing and more. Internal training opportunities include corporate-wide and specialized training opportunities for different job functions. Our Field Career Path Program (FCPP) promotes career growth for our frontline customer-facing employees through established standards of knowledge, skills, abilities and performance.

Employee Safety and Wellness

Safety is one of our company values, a top priority in all we do and deeply embedded in our culture. Meetings of three or more employees begin with a safety share, a practice which contributes to keeping safety top of mind. Since 2009, we have reduced workplace injuries by more than 64% and continue to see long-term, sustained improvements in our safety practices and performance.

	For the year ended December 31, 2023
Total Case Incident Rate (incidents per 200,000 hours worked)	1.51
Preventable Motor Vehicle Incident Rate (vehicle accidents per 1 million miles driven)	1.65
Proactive Safety Activities per Employee	4
% of injuries reported within 1 day	93.3%

ITEM 1A. RISK FACTORS

The nature of our business subjects us to a number of uncertainties and risks. Risks that may adversely affect our business operations, financial condition, results of operations or cash flows are described below. These risk factors, along with other risk factors that we discuss in our periodic reports filed with the SEC should be considered for a better understanding of our Company.

STRATEGIC RISK

Our continued success is dependent on execution of our business plan and growth strategy, including our capital investment program.

Our continued success depends, in significant part, on our ability to execute our strategic business plans. Our strategy is centered on four critical priorities: *Growth*—to grow strategically and achieve strong financial performance, *Operational Excellence*—delivering safe, reliable and cost-effective energy to meet our customers' needs, *Transformation*—be a simple and connected company positioned for growth, and *People & Culture*—retain and attract a talented, engaged and thriving team. Our current plans and strategy may be negatively impacted by disruptive forces and innovations in the marketplace, workforce capabilities, changing political, business or regulatory conditions and technology advancements.

In addition, we have significant capital investment programs planned for the next five years that are key to our strategic business plans. The successful execution of our capital investment program depends on, or could be affected by, a variety of factors that include, but are not limited to: access to capital to fund projects, weather conditions, effective management of projects, availability of qualified construction personnel including contractors, changes in commodity and other prices, impacts of supply chain disruptions on availability and cost of materials, governmental approvals and permitting, regulatory cost recovery and return on investment.

An inability to successfully and timely adapt to changing conditions and execute our strategic plans could materially affect our financial operating results including earnings, cash flow and liquidity.

REGULATORY, LEGISLATIVE AND LEGAL RISKS

We may be subject to unfavorable or untimely federal and state regulatory outcomes.

Our regulated Utilities are subject to cost-of-service/rate-of-return regulation and earnings oversight from federal and eight state utility commissions. This regulatory treatment does not provide any assurance as to achievement of desired earnings levels. Our customer rates are regulated based on an analysis of our costs and investments, as reviewed and approved in regulatory proceedings. While rate regulation is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that our various regulatory authorities will judge all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will result in full or timely recovery of our costs with a reasonable return on invested capital. In addition, adverse rate decisions, including rate moratoriums, rate refunds, limits on rate increases, lower allowed returns on investments or rate reductions, could be influenced by competitive, economic, political, legislative, public perception and regulatory pressures and adversely impact earnings, cash flow and liquidity.

Each of our Utilities are permitted to recover certain costs (such as increased fuel and purchased power costs, including costs from certain severe weather events, or integrity capital investments) outside of a base rate review in order to stabilize customer rates and reduce regulatory lag. If regulators decide to discontinue these tariff-based recovery mechanisms, it could negatively impact earnings, cash flow and liquidity.

Costs could significantly increase to achieve or maintain compliance with existing or future environmental laws, regulations or requirements including those associated with climate change.

Our business segments are subject to numerous environmental laws and regulations affecting many aspects of present and future operations, including air emissions (i.e., SO_2, NO_x, volatile organic compounds, particulate matter and GHG), water quality, wastewater discharges, solid waste and hazardous waste.

These laws and regulations may result in increased capital, operating and other costs. These laws and regulations generally require the business segments to obtain and comply with a wide variety of environmental licenses, permits, inspections and other government approvals. Compliance with environmental laws and regulations may require significant expenditures, including expenditures for cleanup costs and damages arising from contaminated properties. Failure or inability to comply with evolving environmental regulations may result in the imposition of fines, penalties and injunctive measures affecting operating assets.

Our business segments may not be successful in recovering increased capital and operating costs incurred to comply with new environmental regulations through existing regulatory rate structures and contracts with customers. More stringent environmental laws or regulations could result in additional costs of operation for existing facilities or impede the development of new facilities.

There is significant uncertainty regarding if and when new climate legislation, regulations or administrative policies will be adopted to reduce or limit GHG and the impact any such regulations would have on us. New or more stringent regulations or other energy efficiency requirements could require us to incur significant additional costs relating to, among other things, the installation of additional emission control equipment, the acceleration of capital expenditures, the purchase of additional emissions allowances or offsets, the acquisition or development of additional energy supply from renewable resources, the closure or capacity reductions of coal-fired power generation facilities or conversion to alternative fuels, and potential increased production from our combined cycle natural gas-fired generating units. Additional rules and regulations associated with fossil fuels and GHG emissions could result in the impairment or retirement of some of our existing or future transmission, distribution, generation and natural gas storage facilities or our coal mine. Further, these rules could create the need to purchase or build clean-energy fuel sources to fulfill obligations to our customers. These actions could also result in increased operating costs which could adversely impact customers and our financial operating results including earnings, cash flow and liquidity. We cannot definitively estimate the effect of GHG legislation or regulation on our earnings, cash flow and liquidity.

Legislative and regulatory requirements may result in compliance penalties.

Business activities in the energy sector are heavily regulated, primarily by agencies of the federal government. Many agencies employ mandatory civil penalty structures for regulatory violations. The FERC, NERC, PHMSA, CFTC, EPA, OSHA, SEC, TSA and MSHA may impose significant civil and criminal penalties to enforce compliance requirements relative to our business, which could have a material adverse effect on our financial operating results including earnings, cash flow and liquidity.

Municipal governments may seek to limit or deny our franchise privileges.

Municipal governments within our utility service territories possess the power of condemnation and could establish a municipal utility within a portion of our current service territories by limiting or denying franchise privileges for our operations and exercising powers of condemnation over all or part of our utility assets within municipal boundaries. We regularly engage in negotiations on renewals of franchise agreements with our municipal governments. We have from time to time faced challenges or ballot initiatives on franchise renewals. To date, we have been successful in resolving or defending most of these challenges. Although condemnation is a process that is subject to constitutional protections requiring just and fair compensation, as with any judicial procedure, the outcome is uncertain. If a municipality sought to pursue this course of action, we cannot assure that we would secure adequate recovery of our investment in assets subject to condemnation. We also cannot quantify the impact that such action would have on the remainder of our business operations.

Changes in Federal tax law may significantly impact our business.

We are subject to taxation by the various taxing authorities at the federal, state and local levels where we operate. Sweeping legislation or regulation could be enacted by any of these governmental authorities which may affect our tax burden. Changes may include numerous provisions that affect businesses, including changes to corporate tax rates, business-related exclusions, and deductions and credits. The outcome of regulatory proceedings regarding the extent to which a change in corporate tax rate will affect our utility customers and the time period over which that change will occur could significantly impact future earnings and cash flows. Separately, a challenge by a taxing authority, changes in taxing authorities' administrative interpretations, decisions, policies and positions, our ability to utilize tax benefits such as carryforwards or tax credits, or a deviation from other tax-related assumptions may cause actual financial results to deviate from previous estimates.

OPERATING RISKS

Failure to attract and retain an appropriately qualified workforce could have a negative impact on our operations and long-term business strategy.

Recent trends, such as a competitive and tight labor market and an aging workforce may lead to higher costs and increased risk of negative outcomes for safety, compliance, customer service, and operations. Our ability to transition and replace our retirement-eligible utility employees is a risk; at December 31, 2023, approximately 18% of our employees were eligible for retirement. Our ability to avoid or minimize work stoppages and labor disputes is also a risk with approximately 25% of our employees represented by unions. Failure to hire and retain qualified employees, including the ability to transfer significant internal historical knowledge and expertise to new employees, may adversely affect our ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce and maintain satisfactory collective bargaining agreements, safety, service reliability, customer satisfaction and our results of operations could be adversely affected. As part of our strategic business plans, we will need to attract and retain personnel who are qualified to implement our strategy and may need to retrain or re-skill certain employees to support our long-term objectives.

Supply chain challenges could negatively impact our operations.

We rely on various suppliers in our supply chain for the materials necessary to execute on our capital investment program that is key to our strategic business plans and to respond to a significant unplanned event such as a natural disaster. Our largest customers also rely on our supply chain and delays in critical materials could impact their ability to operate and grow as planned. Our supply chain, material costs, and capital investment program may be negatively impacted by:

- Unanticipated price increases due to recent macroeconomic factors, such as inflation, including wage inflation, or rising demand for raw materials associated with the Energy Transition; and
- Supply restrictions beyond our control or the control of our suppliers such as disruption of the freight system (e.g. labor union strikes), increased environmental threats from weather-related disasters, rising demand for raw materials associated with the Energy Transition and/or geopolitical unrest (e.g. Russia-Ukraine and Middle East conflicts).

An inability to successfully manage challenges in our supply chain network could materially affect our ability to execute our business plan and growth strategy and our financial operating results including earnings, cash flow and liquidity.

Our financial performance depends on the successful operation of electric generating facilities, electric and natural gas transmission and distribution systems, natural gas storage facilities and a coal mine.

The risks associated with managing these operations include:

- Operating hazards. Operating hazards such as leaks, mechanical problems and accidents, including fires or explosions, could impact employee and public safety, reliability and customer confidence;
- Inherent dangers. Electricity and natural gas can be dangerous to employees and the general public. Failures of or contact with power lines, natural gas pipelines or service facilities and equipment may result in fires, explosions, property damage and personal injuries, including death. While we maintain liability and property insurance coverage, such policies are subject to certain limits and deductibles. The occurrence of any of these events may not be fully covered by our insurance;
- Weather, natural conditions and disasters including impacts from climate change (discussed below);
- Acts of sabotage, terrorism or other malicious physical attacks. Damage to our facilities due to deliberate acts could lead to outages or other adverse effects;
- Equipment and processes. Breakdown or failure of equipment or processes, unavailability or increased cost of equipment, and performance below expected levels of output or efficiency could negatively impact our results of operations;
- Disrupted transmission and distribution. We depend on transmission and distribution facilities, including those operated by unaffiliated parties, to deliver the electricity and natural gas that we sell to our retail and wholesale customers. If transmission is interrupted physically, mechanically or with cyber means, our ability to sell or deliver utility services and satisfy our contractual obligations may be hindered;
- Natural gas supply for generation and distribution. Our regulated Utilities and non-regulated entities purchase natural gas from a number of suppliers for our generating facilities and for distribution to our customers. Our results of operations could be negatively impacted by the lack of availability and cost of natural gas, and disruptions in the delivery of natural gas due to various factors, including but not limited to, transportation delays, labor relations, weather, sabotage, cyber-attacks and environmental regulations;
- Replacement power. The cost of supplying or securing replacement power during scheduled and unscheduled outages of generation facilities could negatively impact our results of operations;
- Governmental permits. The inability to obtain required governmental permits and approvals along with the cost of complying with or satisfying conditions imposed upon such approvals could negatively impact our ability to operate and our results of operations;
- Operational limitations. Operational limitations imposed by environmental and other regulatory requirements and contractual agreements, including those that restrict the timing of generation plant scheduled outages, could negatively impact our results of operations;
- Increased costs. Increased capital and operating costs to comply with increasingly stringent laws and regulations, unexpected engineering, environmental and geological problems, and unanticipated cost overruns could negatively impact our results of operations;
- Supply chain challenges (discussed above);
- Workforce capabilities and labor relations (discussed above); and

- Public opposition. Opposition by members of public or special-interest groups could negatively impact our ability to operate our businesses.

Any of these risks described above could damage our reputation and public confidence. These risks could also cause us to incur significant costs or be unable to deliver energy and/or operate below expected capacity levels, which in turn could reduce revenues or cause us to incur higher operating and maintenance costs and penalties. While we maintain insurance, obtain warranties from vendors and obligate contractors to meet certain performance levels, the proceeds of such insurance and our rights under contracts, warranties or performance guarantees may not be timely or adequate to cover lost revenues, increased expenses, liability or liquidated damage payments.

The nature of our business subjects us to climate-related risk, stemming from both physical risk and transition risk of climate change, over varying time horizons.

Physical risks of climate change refer to risks to our facilities or operations that may result from changes in the physical climate, such as changes to temperature and weather patterns. Our utility businesses are seasonal businesses and weather conditions and patterns can have a material impact on our operating results. To the extent weather conditions are affected by climate change, fluctuations in commodity prices and customers' energy usage could be magnified. Climate change may lead to increased intensity and frequency of storms, resulting in increased likelihood of fire, wind and extreme temperature events. Severe weather events, such as snow and ice storms (e.g., Winter Storm Uri), fire, and strong winds could negatively impact our operations, including our ability to provide energy safely, reliably and profitably and our ability to complete construction, expansion or refurbishment of facilities as planned. Climate change may intensify these events or increase the frequency of their occurrence. Over time, we may need to make additional investments to protect our facilities from physical risks of climate change.

Transition risks of climate change include changes to the energy systems as a result of new technologies, changing customer demand and/or expectations and voluntary GHG reduction goals, as well as local, state or federal regulatory requirements (discussed above). Policies such as a carbon or methane tax could increase costs associated with fossil fuel usage, resulting in higher operating costs including costs of energy generation, construction, and transportation. Risks of the transition to a low-carbon economy could result in shrinking customer demand for fossil fuel-based energy sources. This could come from increased use of behind the meter technology, such as residential solar and storage. Risk of investor pressure over climate risk and/or ESG standards, activist campaigns against coal producers, employee preferences to work for companies with certain sustainability goals and consumers preference for renewable energy could impact our reputation, ability to attract and retain an appropriately trained workforce, and overall access to capital and/or adequate insurance policies.

Cybersecurity incidents, terrorism, or other malicious acts targeting our key technology systems could disrupt our operations or lead to a loss or misuse of confidential and proprietary information.

To effectively operate our business, we rely upon a sophisticated electronic control system, information and operation technology systems and network infrastructure to generate, distribute and deliver energy, and collect and retain sensitive information including personal information about our customers and employees. Cybersecurity incidents, terrorism or other malicious acts targeting electronic control systems could result in a full or partial disruption of our electric and/or natural gas operations. Attacks targeting other key technology systems, including our third-party vendors' information systems, could further add to a full or partial disruption of our operations. The utility industry has been the target of several cyberattacks on operational systems and has seen an increased volume and sophistication of cybersecurity incidents from international activist organizations, other nation state actors and individuals. To date, we have not experienced a cybersecurity incident that has had a material impact on our business or results of operations. Any disruption of our electric and/or natural gas operations could result in a loss of service to customers and associated revenues, as well as significant expense to repair damages and remedy security breaches. In addition, any theft, loss and/or fraudulent use of customer, shareowner, employee or proprietary data could subject us to significant litigation, liability and costs, as well as adversely impact our reputation with customers and regulators, among others. We maintain cyber risk insurance to mitigate a portion, but not all, of these risks and losses.

As discussed in Utility Regulation Characteristics above, in 2021 the TSA issued security directives that included several new cybersecurity requirements for critical pipeline owners and operators. Such directives or other requirements may require expenditure of significant additional resources to respond to cybersecurity incidents, to continue to modify or enhance protective measures, or to assess, investigate and remediate any critical infrastructure security vulnerabilities. Any failure to comply with such government regulations or failure in our cybersecurity protective measures may result in enforcement actions that may have a material adverse effect on our business, results of operations and financial condition. In addition, there is no certainty that costs incurred related to securing against threats will be recovered through rates.

As discussed in Item 1C in this Annual Report on Form 10-K, we have instituted security measures and safeguards to protect our operational systems and information technology assets against cybersecurity threats, including certain safeguards required by NERC. Despite our implementation of security measures and safeguards, all of our technology systems may still be vulnerable to disability, failures or unauthorized access.

Our operations are subject to various conditions that can result in fluctuations in customer usage, including customer growth and general economic conditions in our service territories, weather conditions, and responses to price increases and technological improvements.

Our results of operations and cash flows are affected by the demand for electricity and natural gas, which can vary greatly based upon:

- Fluctuations in customer growth and general economic conditions in our service territories. Customer growth and energy use can be negatively impacted by population declines as well as adverse economic factors in our service territories, including recession, inflation, workforce reductions, stagnant wage growth, changing levels of support from state and local government for economic development, business closings, and reductions in the level of business investment. Our Utilities are impacted by economic cycles and the competitiveness of the commercial and industrial customers we serve. Any economic downturn, inflation, disruption of financial markets, or reduced incentives by state government for economic development could adversely affect the financial condition of our customers and demand for their products or services. These risks could directly influence the demand for electricity and natural gas as well as the need for additional power generation and generating facilities. We could also be exposed to greater risks of accounts receivable write-offs if customers are unable to pay their bills.
- Weather conditions. Our Utilities are seasonal businesses and weather conditions and patterns can have a material impact on our operating performance. Demand for electricity is typically greater in the summer and winter months associated with cooling and heating, respectively. Demand for natural gas depends heavily upon winter-weather patterns throughout our service territory and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our Utilities have historically generated lower revenues, income and cash flows when weather conditions are cooler than normal in the summer and warmer than normal in the winter. Demand for natural gas is also impacted by summer weather patterns that are cooler than normal and provide higher than normal precipitation; both of which can reduce natural gas demand for irrigation. Unusually mild summers and winters, therefore, could have an adverse effect on our financial operating results, including earnings, cash flow and liquidity.
- Our customers' focus on energy conservation. Customer growth and usage may be impacted by the voluntary reduction in consumption of electricity and natural gas by our customers in response to increases in prices and energy efficiency programs, electrification initiatives that could negatively impact the demand for natural gas, economic conditions (i.e., inflation, recession) impacting customers’ disposable income and the use of distributed generation resources or other emerging technologies. Continued technological improvements may make customer and third-party distributed generation and energy storage systems, including fuel cells, micro-turbines, wind turbines, solar cells and batteries, more cost effective and feasible for our customers. If more customers utilize their own generation, demand for energy from us could decline. Such developments could affect the price and/or delivery of energy, require further improvements to our distribution systems to address changing load demands and could make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives.

Each of these factors described above could materially affect demand for electricity and natural gas which would impact our financial operating results including earnings, cash flow and liquidity.

If macroeconomic or other conditions adversely affect operations or require us to make changes to our strategic business plan, we may be forced to record a non-cash goodwill impairment charge.

We had approximately $1.3 billion of goodwill on our consolidated balance sheets as of December 31, 2023. If we make changes in our strategic business plan and growth strategy, or if macroeconomic or other conditions adversely affect operations in any of our businesses, we may be required to record a non-cash impairment charge. Goodwill is tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. If the testing performed indicates that impairment has occurred, we are required to record an impairment charge for the difference between the carrying value of the goodwill and the implied fair value of the goodwill in the period the determination is made. The testing of goodwill for impairment requires us to make significant estimates about our future performance and cash flows, as well as other assumptions. These estimates can be affected by numerous factors, including: future business operating performance, changes in macroeconomic conditions including recession, inflation and interest rates, changes in our regulatory environment, industry-specific market conditions, changes in business operations, changes in competition or changes in technologies. Any changes in key assumptions, or actual performance compared with key assumptions, about our business and its future prospects could affect the fair value of either or both of our operating segments, which may result in an impairment charge. See additional information in “Critical Accounting Estimates” under Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operations and Note 1 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

FINANCIAL RISKS

A sub-investment grade credit rating could impact our ability to access capital markets.

Our senior unsecured debt rating is Baa2 (Stable outlook) by Moody's; BBB+ (Stable outlook) by S&P; and BBB+ (Negative outlook) by Fitch. Reduction of our investment grade credit ratings could impair our ability to refinance or repay our existing debt and complete new financings on reasonable terms. A credit rating downgrade, particularly to sub-investment grade, could also result in counterparties requiring us to post additional collateral under existing or new contracts. In addition, a ratings downgrade would increase our interest expense under some of our existing debt obligations, including borrowings under our credit facilities, potentially significantly increasing our cost of capital and other associated operating costs which may not be recoverable through existing regulatory rate structures and contracts with customers.

We may be unable to obtain financing on reasonable terms needed to refinance debt, fund planned capital expenditures or otherwise execute our operating strategy.

Our ability to execute our operating strategy is highly dependent upon our access to capital. Historically, we have addressed our liquidity needs (including funds required to make scheduled principal and interest payments, refinance debt, pay dividends and fund working capital and planned capital expenditures) with operating cash flow, borrowings under credit facilities, proceeds of debt and equity offerings and proceeds from asset sales. Our ability to access capital markets and the costs and terms of available financing depend on many factors, including changes in our credit ratings, general macroeconomic conditions which may drive changes in interest rates and cause volatility in our stock price, changes in the federal or state regulatory environment affecting energy companies and volatility in commodity prices.

In addition, because we are a holding company and our utility assets are owned by our subsidiaries, if we are unable to adequately access the credit markets, we could be required to take additional measures designed to ensure that our utility subsidiaries are adequately capitalized to provide safe and reliable service. Possible additional measures would be evaluated in the context of then-prevailing market conditions, prudent financial management and any applicable regulatory requirements.

Costs associated with our healthcare plans and other benefits could increase significantly.

The costs of providing healthcare benefits to our employees and retirees have increased substantially in recent years. We believe that our employee benefit costs, including costs related to healthcare plans for our employees and former employees, will continue to rise. Significant regulatory developments have required, and likely will continue to require, changes to our current employee benefit plans and supporting administrative processes. Our electric and natural gas utility rates are regulated on a state-by-state basis by the relevant state regulatory authorities based on an analysis of our costs, as reviewed and approved in a regulatory proceeding. Within our utility rates, we have generally recovered the cost of providing employee benefits. As benefit costs continue to rise, however, there is no assurance that the utility commissions will allow recovery of these increased costs. The rising employee benefit costs, or inadequate recovery of such costs, may adversely affect our financial operating results including earnings, cash flow, and liquidity.

We may be unable to obtain insurance coverage, and the coverage we currently have may not apply or may be insufficient to cover a significant loss.

Our ability to obtain insurance, as well as the cost of such insurance, could be impacted by developments affecting the insurance industry and the financial condition of insurers. Additionally, insurance providers could deny coverage or decline to extend coverage under the same or similar terms that are presently available to us. A loss for which we are not adequately insured could materially affect our financial results. The coverage we currently have in place may not apply to a particular loss, or it may not be sufficient to cover all liabilities to which we may be subject, including liability and losses associated with wildfires, natural gas and storage field explosions, cyber-security breaches, environmental hazards and natural disasters.

We have a holding company corporate structure with multiple subsidiaries. Corporate dividends and debt payments are dependent upon cash distributions to the holding company from the subsidiaries.

As a holding company, our investments in our subsidiaries are our primary assets. Our operating cash flow and ability to service our indebtedness depend on the operating cash flow of our subsidiaries and the payment of funds by them to us in the form of dividends or advances. Our subsidiaries are separate legal entities that have no obligation to make any funds available for that purpose, whether by dividends or otherwise. In addition, each subsidiary's ability to pay dividends to us depends on any applicable contractual or regulatory restrictions that may include requirements to maintain minimum levels of cash, working capital, equity or debt service funds.

There is no assurance as to the amount, if any, of future dividends to the holding company because these subsidiaries depend on future earnings, capital requirements and financial conditions to fund such dividends. See “Liquidity and Capital Resources” within Management’s Discussion and Analysis of Financial Condition and Results of Operations in Item 7 and Note 8 of the Notes to Consolidated Financial Statements of this Annual Report on Form 10-K for further information regarding these restrictions and their impact on our liquidity.

Market performance or changes in key valuation assumptions could require us to make significant unplanned contributions to our pension plan and other postretirement benefit plans.

Assumptions related to interest rates, expected return on investments, mortality and other key actuarial assumptions have a significant impact on our funding requirements and the expense recognized related to our pension and other postretirement benefit plans. An adverse change to key assumptions associated with our defined benefit retirement plans may require significant unplanned contributions to the plans which could adversely affect our financial operating results including earnings, cash flow and liquidity. See Note 13 of the Notes to Consolidated Financial Statements of this Annual Report on Form 10-K for further information

Our use of derivative financial instruments as hedges against commodity prices and financial market risks could result in material financial losses.

We use various financial and physical derivatives, including futures, forwards, options and swaps, to manage commodity price and interest rate risks. The timing of the recognition of gains or losses on these economic hedges in accordance with GAAP may not consistently match up with the gains or losses on the commodities being hedged. For Black Hills Energy Services under the Choice Gas Program, and in certain instances within our regulated Utilities where unrealized and realized gains and losses from derivative instruments are not approved for regulatory accounting treatment, fluctuating commodity prices may cause fluctuations in reported financial results due to mark-to-market accounting treatment.

To the extent that we hedge our commodity price and interest rate exposures, we forgo the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor. In addition, even though they are closely monitored by management, our hedging activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the hedge arrangement, the hedge is economically imperfect, commodity prices or interest rates move unfavorably related to our physical or financial positions, or hedging policies and procedures are not followed.

Additionally, our exchange-traded futures contracts are subject to futures margin posting requirements. To the extent we are unable to meet these requirements, this could have a significant impact on our business by reducing our ability to execute derivative transactions to reduce commodity price uncertainty and to protect cash flows. Requirements to post collateral may cause significant liquidity issues by reducing our ability to use cash for investment or other corporate purposes or may require us to increase our level of debt. Further, a requirement for our counterparties to post collateral could result in additional costs being passed on to us, thereby decreasing our profitability.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

The utility industry has been the target of several cyberattacks on operational systems and has seen an increased volume and sophistication of cybersecurity incidents from international activist organizations, other nation state actors and individuals. We expect to continue to experience attempts to compromise our information technology and control systems, network infrastructure and other assets. To date, we have not experienced a cybersecurity incident that has had a material impact on our business or results of operations.

Risk Management and Strategy

Our enterprise risk management program, which includes cybersecurity risks that are identified through our cybersecurity risk management program, is designed to identify, report, and manage relevant material risks and opportunities.
Management of the identified risks is embedded into business processes and key decision making at every level of the Company. Our enterprise risk management team works closely with our Chief Security Officer ("CSO") and IT risk management team to evaluate and address material cybersecurity risks in alignment with our business strategy and operational needs.

We have a cybersecurity risk management program that is managed by a team of full-time cybersecurity professionals that utilizes a variety of tools and techniques to identify and assess material cybersecurity threats, their potential impact and opportunities for mitigation. The industry-standard security frameworks that we apply to our cyber environment include various security and risk assessments, such as internal threat assessments and internal control self-assessments. Because we are aware of the risks associated with third-party providers, we conduct third-party provider security assessments and benchmarking before engagement and maintain ongoing monitoring to ensure compliance with our cybersecurity standards. These assessments include evaluation of risk profiles through vendor questionnaires, review of System and Organization Controls attestation reports and monitoring on an ongoing basis by our IT risk management team. This approach is designed to mitigate risks related to data breaches or other security incidents originating from third-parties.

We regularly engage with third-party assessors and auditors as part of our ongoing cybersecurity risk assessment process to leverage specialized knowledge and insights and to identify areas for continued focus, improvement, compliance and effectiveness of mitigation. We also utilize government and industry-related security intelligence sources, and actively participate in industry peer groups and public-private partnerships to assist in the identification of potential threats. We conduct ongoing cybersecurity training and monthly email phishing drills for all employees.

We also have a cybersecurity incident response plan and procedures to manage cybersecurity incidents. These procedures include steps to identify, classify, communicate, contain, eradicate, and recover from a cybersecurity incident. These procedures also include notification to a cross-functional management team to assess incident materiality and an escalation process to members of our senior management team and our Board of Directors.

Governance

Our Board of Directors is responsible for the oversight of risks from cybersecurity threats. Our Chief Information Officer provides our Board of Directors quarterly reports that summarize material cybersecurity threats and the countermeasures taken to mitigate the associated risks. These reports address a variety of topics including updates on strategic cyber initiatives, industry trends, threat vulnerability assessments, and efforts to prevent, detect and respond to internal and external critical threats. From time to time, our Board of Directors also engages third-party consultants to provide further education about cybersecurity risks.

Our cybersecurity risk management program, which is discussed above, is led by our CSO, who has 28 years of prior work experience in various roles involving managing information security of large-scale global security operations, including developing cybersecurity strategy and implementing effective information and cybersecurity programs. Our CSO maintains industry certifications, including an ISC2 Certified Information Systems Security Professional certification.

Through oversight of the cybersecurity risk management program, our CSO is continually informed about the status of the program, including the effectiveness of the process and controls to monitor, prevent, detect, mitigate, and remediate cybersecurity incidents. The CSO is also made aware of the latest developments in cybersecurity, including potential threats and innovative risk management techniques. The CSO, in his capacity, regularly informs the Chief Information Officer and other members of our senior management team of all aspects related to cybersecurity risks and incidents.

ITEM 2. PROPERTIES

See Item 1 for a description of our principal business properties.

In addition to the properties disclosed in the Item 1, we own or lease several facilities throughout our service territories including a corporate headquarters building and various office, service center, storage, shop and warehouse space. Substantially all of the tangible utility properties of South Dakota Electric and Wyoming Electric are subject to liens securing first mortgage bonds issued by South Dakota Electric and Wyoming Electric, respectively.

ITEM 3. LEGAL PROCEEDINGS

Information regarding our legal proceedings is incorporated herein by reference to the “Legal Proceedings” sub-caption within Item 8, Note 3, “Commitments, Contingencies and Guarantees”, of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

ITEM 4. MINE SAFETY DISCLOSURES

Information concerning mine safety violations or other regulatory matters required by Sections 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act is included in Exhibit 95 of this Annual Report.

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INFORMATION ABOUT OUR EXECUTIVE OFFICERS

Linden R. Evans, age 61, has been President and Chief Executive Officer since January 1, 2019, President and Chief Operating Officer from 2016 through 2018, and President and Chief Operating Officer - Utilities from 2004 through 2015. Mr. Evans served as the Vice President and General Manager of our former communication subsidiary in 2003 and 2004, and Associate Counsel from 2001 to 2003. Mr. Evans has 22 years of experience with the Company.

Brian G. Iverson, age 61, has been Senior Vice President, General Counsel and Chief Compliance Officer since August 26, 2019. He served as Senior Vice President, General Counsel, Chief Compliance Officer and Corporate Secretary from February 1, 2019 to August 26, 2019, Senior Vice President, General Counsel and Chief Compliance Officer from 2016 to February 2019, Senior Vice President - Regulatory and Governmental Affairs and Assistant General Counsel from 2014 to 2016, Vice President and Treasurer from 2011 to 2014, Vice President - Electric Regulatory Services from 2008 to 2011 and as Corporate Counsel from 2004 to 2008. Mr. Iverson has 20 years of experience with the Company.

Todd Jacobs, age 55, has been Senior Vice President Growth and Strategy since June 15, 2023. Mr. Jacobs spent seven years in operations roles at the company, serving as the state leader for our Kansas and Arkansas utilities from 2014 to 2019 and then as the segment leader of our natural gas utilities from 2019 to 2021. He led our strategic planning and growth efforts from 2021 to 2023 before moving into this newly expanded role in 2023, which includes growth, strategic planning, business development, regulatory, government affairs, sustainability, communications and community affairs. He served in legal and corporate services leadership roles with other investor-owned utilities before joining the company in 2014. Mr. Jacobs served on active duty for seven years as a U.S. Army officer.

Marne M. Jones, age 50, has been Senior Vice President Utilities since June 15, 2023. She served as VP Electric Utilities from 2021 to 2023, Vice President Regulatory and Finance from 2018 to 2021 and Vice President Regulatory from 2016 to 2018. Ms. Jones has a total of 22 years of experience with the Company and has advanced through roles of increasing responsibility in finance, accounting, corporate services, regulatory and utility operations.

Erik D. Keller, age 60, joined the Company as Senior Vice President and Chief Information Officer on July 27, 2020. Prior to joining the company, he was an Information Technology consultant to Ontic Inc., a global provider of parts and services for legacy aerospace platforms, from January 2020 to July 2020, and Chief Information Officer for BBA Aviation, a global aviation support and aftermarket services provider, from February 2012 to January 2020.

Kimberly F. Nooney, age 52, has been Senior Vice President and Chief Financial Officer since April 1, 2023. She served as Vice President – Treasurer from 2015 to 2023, and also served as the Corporate Controller from 2018 to 2022. Ms. Nooney has a total of 27 years of experience with the Company across numerous roles within accounting, internal audit, corporate development, accounting systems, treasury and financial planning and analysis.

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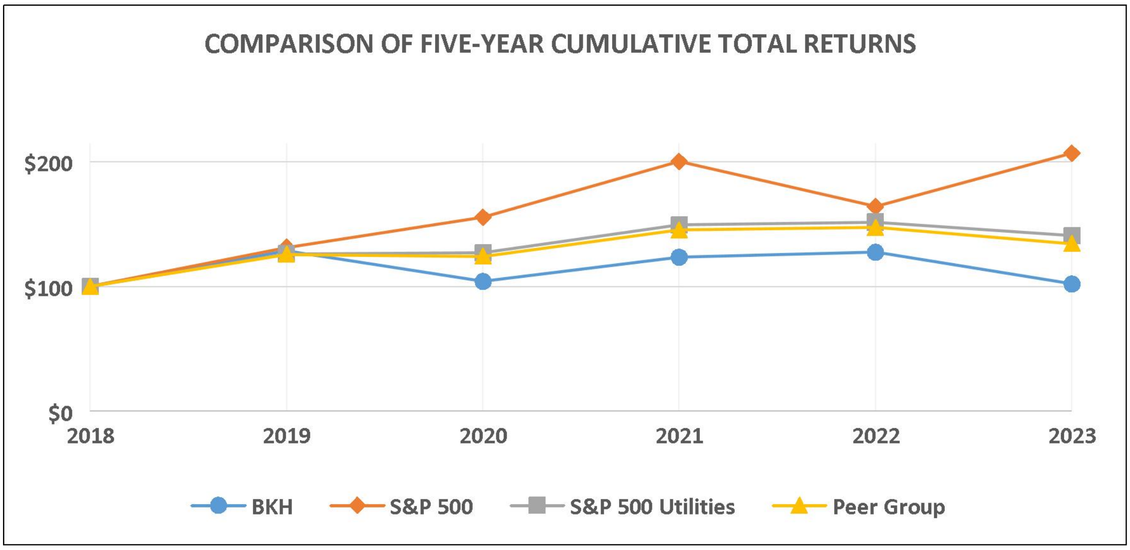
PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is traded on the New York Stock Exchange under the symbol BKH. As of January 31, 2024, we had 3,244 common shareholders of record and 63,074 beneficial owners, representing all 50 states, the District of Columbia, Puerto Rico and 5 foreign countries.

COMPARATIVE STOCK PERFORMANCE

The following performance graph compares the cumulative total stockholder return from Black Hills Corporation common stock, as compared with the S&P 500 Index, S&P 500 Utilities index, and our Performance Peer Group for the past five years. The graph assumes an initial investment of $100 on December 31, 2018, and assumes all dividends were reinvested. The stockholder return shown below for the five-year historical period may not be indicative of future performance. The information in this "Comparative Stock Performance" section shall not be deemed to be "soliciting material" or to be "filed" with the Securities and Exchange Commission or subject to Regulation 14A or 14C, or to the liabilities of Section 18 of the Securities Exchange Act of 1934.



	As of December 31,					
	2018	2019	2020	2021	2022	2023
Black Hills Corporation	$ 100.00	$ 128.59	$ 104.05	$ 123.69	$ 127.49	$ 102.08
S&P 500	100.00	131.49	155.68	200.37	164.08	207.21
S&P 500 Utilities	100.00	126.35	126.96	149.39	151.73	140.99
Performance Peer Group [a]	100.00	125.79	124.33	145.61	147.29	134.47

(a) Performance Peer Group represents the Edison Electric Institute Index, which was used in our 2023 Proxy Statement filed with the SEC on March 15, 2023.

DIVIDENDS

For information concerning dividends, our dividend policy and factors that may limit our ability to pay dividends, see "Key Elements of our Business Strategy" and "Liquidity and Capital Resources" under Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations in this Annual Report on Form 10-K.

UNREGISTERED SECURITIES ISSUED

There were no unregistered securities sold during 2023.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

See Item 12 in this Annual Report on Form 10-K for information regarding Securities Authorized for Issuance Under Equity Compensation Plans.

ISSUER PURCHASES OF EQUITY SECURITIES

The following table contains monthly information about our acquisitions of equity securities for the three months ended December 31, 2023:

Period	Total Number of Shares Purchased [(a)]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
October 1, 2023 - October 31, 2023	47	$ 48.44	—	—
November 1, 2023 - November 30, 2023	991	$ 51.52	—	—
December 1, 2023 - December 31, 2023	7,018	$ 54.62	—	—
Total	8,056	$ 54.20	—	—

(a) Shares were acquired under the share withholding provisions of the Amended and Restated 2015 Omnibus Incentive Plan for payment of taxes associated with the vesting of various equity compensation plans.

ITEM 6. (RESERVED)

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Executive Summary

We are a customer-focused energy solutions provider with a mission of *Improving Life with Energy* for more than 1.3 million customers and 800+ communities we serve. Our aspiration is to be the trusted energy partner across our growing eight-state footprint, including Arkansas, Colorado, Iowa, Kansas, Montana, Nebraska, South Dakota and Wyoming. Our strategy is centered on four critical priorities: *Growth*—to grow strategically and achieve strong financial performance, *Operational Excellence*—delivering safe, reliable and cost-effective energy to meet our customers' needs, *Transformation*—be a simple and connected company positioned for growth, and *People & Culture*—retain and attract a talented, engaged and thriving team.

We conduct our business operations through two operating segments: Electric Utilities and Gas Utilities. Certain unallocated corporate expenses that support our operating segments are presented as Corporate and Other. We conduct our utility operations under the name Black Hills Energy predominantly in rural areas of the Rocky Mountains and Midwestern states. We consider ourself a domestic electric and natural gas utility company.

We have provided energy and served customers for 140 years, since the 1883 gold rush days in Deadwood, South Dakota. Throughout our history, the common thread that unites the past to the present is our commitment to serve our customers and communities. By being responsive and service focused, we can help our customers and communities thrive while meeting rapidly changing customer expectations.

Key Elements of our Business Strategy

Explore opportunities as an energy solutions provider. A key strategic initiative is to grow our business through innovative energy solutions with new customers and partnerships. We see value creation by recruiting new customers and expanding existing partnerships with data centers and blockchain opportunities; exploring energy markets such as RTOs; and expanding our transmission capabilities, establishing a RNG program and expanding our RNG portfolio. A few recent examples of our initiatives to grow our business as an energy solutions provider include:

- *Contracted Renewable Energy to Grow Data Center Partnerships:* In 2022, Wyoming Electric entered into two new PPAs with third parties to purchase up to 106 MW of wind energy and up to 150 MW of solar energy, upon construction of new renewable generation facilities (owned by third parties). The new wind generation facility was placed in service in December 2023 and the solar facility is expected to be completed in March 2024. The renewable energy from these PPAs will be used to serve our expanding partnerships with data centers.

- *Developed BCIS Tariff to Facilitate Growth:* We have supported enabling legislation in Wyoming for the growing blockchain businesses while implementing our own BCIS Tariff to serve these customers. In June 2022, Wyoming Electric completed its first agreement, with a new customer in Cheyenne, Wyoming, under this Tariff. This five-year agreement provides delivery of up to 45 MW with an option to expand service up to 75 MW, which was exercised by the customer in 2023. Energy is sourced through the electric energy market and delivered through our Electric Utilities' infrastructure. Under the agreement, the customer is responsible for costs of service, and the load is interruptible to prioritize the needs of Wyoming Electric's existing retail customers.

- *Established Green Forward:* In 2022 and 2023, we filed regulatory applications to launch Green Forward, a voluntary RNG and carbon offset program, to eligible residential and small business natural gas customers to offset up to 100% or more of the emissions from their natural gas usage. Our teams continue to evaluate attractive RNG investment opportunities across our agriculture-rich service territories and explore value generation with our natural gas storage assets. We also continue to expand our RNG interconnections, with seven projects actively injecting RNG into our natural gas system.

- *Expanded RNG Portfolio:* In January 2024, Black Hills Energy Renewable Resources acquired a RNG production facility at a landfill in Dubuque, Iowa. The facility currently injects RNG into the natural gas distribution system serving Dubuque, which is owned and operated by Iowa Gas. This acquisition represents our entry into the production of RNG as a nonregulated business while leveraging our expertise in owning and operating regulated natural gas pipeline systems, including RNG interconnections. The RNG produced from the landfill facility captures methane that would otherwise vent into the atmosphere. It is delivered under long-term contracts to a third party that purchases the RNG and its related environmental attributes, in conformity with the EPA's Renewable Fuel Standard Program.

Modernize and operate utility infrastructure to provide customers with safe, reliable, cost-effective electric and natural gas service. Our utilities own and operate large electric and natural gas infrastructure systems with a geographic footprint that spans nearly 1,600 miles. Our Electric Utilities own and operate 1,394 MW of generation capacity and 9,106 miles of transmission and distribution lines and our Gas Utilities own and operate approximately 47,000 miles of natural gas transmission and distribution pipelines.

A key strategic focus is to modernize and harden our utility infrastructure to meet customers' and communities' varied energy needs, ensure the continued delivery of safe, reliable and cost-effective energy and reduce GHG emissions intensity. In addition, we invest in the expansion, capacity and integrity of our systems to meet customer growth.

To meet our electric customers' continued expectations of high levels of reliability, a key strength of the Company, our Electric Utilities utilize an integrity program to ensure the timely repair and replacement of aging infrastructure. In alignment with this program, in November 2021, Wyoming Electric announced its *Ready Wyoming* electric transmission expansion initiative. The 260-mile, multi-phase transmission expansion project will provide customers long-term price stability and greater flexibility as power markets develop in the Western States. Construction of the project commenced in late 2023 and is expected to take place in multiple phases or segments through 2025 and will interconnect South Dakota Electric's and Wyoming Electric's transmission systems.

Our Gas Utilities utilize a programmatic approach to system-wide pipeline replacement, particularly in high consequence areas. Under the programmatic approach, obsolete, at-risk and vintage materials are replaced in a proactive and systematic time frame. We have removed all cast- and wrought-iron from our natural gas transmission and distribution systems and continue to replace aging infrastructure through programs that prioritize safety and reliability for our customers. Our Gas Utilities are authorized to use system safety, integrity and replacement cost recovery mechanisms that provide for customer rate adjustments, between rate reviews, which allow timely recovery of costs incurred in repairing and replacing the gas delivery systems with a return on the investment.

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As of December 31, 2023, we estimate our five-year capital investment to be approximately $4.3 billion, with most of that investment targeted toward upgrading existing utility infrastructure supporting customer and community growth needs, and complying with safety requirements. Our actual 2023 and forecasted capital expenditures for the next five years from 2024 through 2028 are as follows (in millions). Minor differences may result due to rounding.

	Actual [(a)]	Forecasted [(b)]				
Capital Expenditures By Segment:	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
(in millions)						
Electric Utilities	$ 211	$ 409	$ 287	$ 466	$ 199	$ 264
Gas Utilities	$ 372	$ 407	$ 387	$ 368	$ 372	$ 373
Corporate and Other	$ 7	$ 24	$ 29	$ 29	$ 27	$ 29
Strategic growth projects	$ -	$ -	$ 100	$ 400	$ 50	$ 50
Total	$ 590	$ 840	$ 803	$ 1,263	$ 648	$ 717

(a) Includes accruals for property, plant and equipment as disclosed as supplemental cash flow information in the Consolidated Statements of Cash Flows in the Consolidated Financial Statements in this Annual Report on Form 10-K. Capital expenditures are presented net of contributions in aid of construction in the Consolidated Statements of Cash Flows.
(b) Projects are being evaluated by our segments for timing, cost and other factors.

Efficiently plan, construct and operate power generation facilities to serve our Electric Utilities. We best serve customers and communities when generation is vertically integrated into our Electric Utilities and we retain control of the fuel source. This business model remains a core strength and strategy today as we invest in and operate efficient power generation resources to supply cost-effective electricity to our customers. These generation assets can be rate-based or non-regulated assets within our Electric Utilities segment. However, we believe that generation assets that are rate-based provide the most effective long-term benefits to customers.

Our power production strategy focuses on low-cost construction and efficient operation of our generating facilities. Our low power production costs result from a variety of factors including low fuel costs (operations located near energy hubs), efficiency in converting fuel into energy and low per unit operating and maintenance costs. In addition, we operate our plants with high levels of Availability as compared to industry benchmarks.

Rate-Based Generation: We continue to believe that customers are best served when the power generation facilities are owned and rate-based by our Electric Utilities. Rate-based generation assets offer several advantages for customers and shareholders, including:

- When generating assets are included in the utility rate base and reviewed and approved by government authorities, customer rates are more stable and predictable, and typically less expensive in the long run; especially when compared to power otherwise purchased from the open market through wholesale contracts or PPAs that are periodically re-priced to reflect current and varying market conditions;
- Regulators participate in a planning process where long-term investments are designed to match long-term energy demand;
- The lower-risk profile of rate-based generation assets contributes to stronger credit ratings which, in turn, can benefit both customers and investors by lowering the cost of capital; and
- Investors are provided a long-term and stable return on their investment.

Integrated Generation: Our Electric Utilities segment also includes a power generation business that owns non-regulated generating facilities that are contracted through long-term power purchase agreements with our electric utilities. Our power generation business has an experienced staff with significant expertise in planning, building and operating power plants. This team also provides shared services to our Electric Utilities' generation facilities, resulting in efficient management of all of the Company's generation assets. Our power generation business competitively bids for energy and capacity through requests for proposals by our Electric Utilities for energy resources necessary to serve customers. This business can bid competitively due to construction expertise, fuel supply advantages and by co-locating new plants at our existing Electric Utilities' energy complexes, reducing infrastructure and operating costs. All power plants within this business are contracted to our Electric Utilities under long-term contracts, located at our utility-generating complexes and physically integrated into our Electric Utilities' operations.

Generation Fuel Supply: Our generating facilities are strategically located close to energy hubs that help reduce fuel supply costs. Our Colorado and Wyoming gas-fired generating facilities are located close to major natural gas energy hubs that provide trading liquidity and transparent pricing. Due to their location in the resource rich areas of Colorado and Wyoming, natural gas supply to fuel our gas-fired generation can be sourced at competitive prices. Our coal-fired power plants, all located at the Gillette Energy Complex in northeastern Wyoming, are supplied by our adjacent WRDC coal mine. WRDC provides approximately 3.7 million tons of low-sulfur coal directly to these power plants via a conveyor belt system, minimizing transportation costs. The fuel can be delivered to our adjacent power plants at very cost competitive prices (i.e., $1.14 per MMBtu for year ended December 31, 2023) when compared to alternatives. Nearly all the mine’s production is sold to these on-site generation facilities under long-term supply contracts. Approximately one-half of our production is sold under cost-plus contracts with affiliates. A small portion of the mine’s production is sold to off-site industrial customers and delivered by truck.

Supporting the Energy Transition by proactively integrating alternative and renewable energy into our utility energy supply while mitigating customer rate impacts. A critical component of our strategy involves sustainable operations and supporting the Energy Transition. How we operate our company for the social good has never been more important. We are committed to cleaner energy and a low carbon future, integrating the Energy Transition and more renewable energy into our overall strategy and decision making. In addition, we are committed to a more sustainable future by better managing our impacts to the planet, whether that is water usage, recycling, biodiversity, or other important measures.

In November 2020, we announced clean energy goals to reduce GHG emissions intensity for our Electric Utilities by 40% by 2030 and 70% by 2040 and achieve GHG reductions of 50% by 2035 for our Gas Utilities. Our goals are compared to a 2005 baseline. Electric Utility goals include Scope 1 emissions from electric utility generating units and Scope 3 emissions from purchased power for sales. Our Gas Utilities goal initially included only Scope 1 emissions from distribution system main and service lines. In August 2022, we announced a new "Net Zero by 2035" target for our Gas Utilities, which doubled the previous target of a 50% reduction by 2035 and expanded the scope of the goal to all Scope 1 sources of methane emissions on our distribution system. Net Zero will be achieved through pipeline material and main replacements, advanced leak detection, third-party damage reduction, expanding the use of RNG and hydrogen, and utilizing carbon credit offsets.

Since 2005, we have reduced GHG emissions intensity from our Electric Utilities by one-third. We have plans in place today, without reliance on future technologies, to achieve our corporate climate goals calling for a 40% reduction in greenhouse gas emissions intensity from our electric utility operations by 2030 and 70% by 2040. Additionally, our Electric Utilities have reduced nitrogen oxide and sulfur dioxide emissions by more than 75% since 2005. Colorado Electric has achieved a nearly 50% reduction in GHG emissions since 2005 and is on track to reach the State of Colorado’s 80% carbon reduction goal by 2030. Our goals are based on prudent and proven solutions to reduce our emissions while minimizing cost impacts to our customers. This keeps our customers at the forefront of our decision-making, which is central to our values.

More of our customers, particularly our larger customers, are demanding cleaner sources of energy to meet their sustainability goals. In addition, there is more interest from consumers, regulators and legislators to increase the use of renewable and other alternative energy sources. Recent efforts to support this interest include:

- In June 2021, South Dakota Electric and Wyoming Electric submitted an IRP to the SDPUC and WPSC. The IRP outlines a range of options for the two electric utilities over a 20-year planning horizon to meet long-term forecasted energy needs while strengthening reliability and resiliency of the grid. The analysis focused on the least-cost resource needs to best meet customers’ future peak energy needs while maintaining system flexibility and achieving the Company’s generation emissions reduction goals. The IRP’s preferred options for South Dakota Electric in the near-term planning period through 2026 are the addition of 100 MW of renewable generation, the conversion of Neil Simpson II to dual fuel (natural gas and coal) in 2025 and consideration of up to 20 MW of battery storage. In 2023, South Dakota Electric issued a request for proposals for 100 MW of utility-owned renewable energy resources to be in service in 2026. Negotiations are underway, with results to be presented to the SDPUC and included in a CPCN filing with the WPSC during the first quarter of 2024.

- In March 2023, the CPUC approved a unanimous settlement for Colorado Electric's Clean Energy Plan filed on May 25, 2022. The Clean Energy Plan supports Colorado Electric's voluntary election to reduce carbon emissions 80% from 2005 levels by 2030. In July 2023, Colorado Electric issued a request for proposals for approximately 400 MW of new renewable resources to be in service by 2029 to achieve objectives in its Clean Energy Plan. Colorado Electric received a strong response to its request for proposal and provided a bids summary to the CPUC as part of the approval process. A report with Colorado Electric's recommended resources is due to the CPUC in the second quarter of 2024.

Many states have enacted, and others are considering, mandatory renewable energy standards, requiring utilities to meet certain thresholds of renewable energy generation. In addition, some states have either enacted or are considering legislation setting GHG emission reduction targets. Federal legislation for renewable energy standards and GHG emission reductions has been considered and may be implemented in the future. Mandates for the use of renewable energy or the reduction of GHG emissions will likely drive the need for significant investment in our Electric Utilities and Gas Utilities segments. These mandates will also likely increase prices for electricity and/or natural gas for our utility customers. As a regulated utility, we are responsible for providing safe, reliable and cost-effective sources of energy to our customers. Accordingly, we employ a customer-focused strategy for complying with standards and regulations that balances our customers' rate concerns with environmental considerations and administrative and legislative mandates. We attempt to strike this balance by prudently and proactively incorporating renewable energy into our resource supply, while seeking to minimize the magnitude and frequency of rate increases for our utility customers.

Inflation Reduction Act

The IRA, signed into law by President Biden in August 2022, features $370 billion in spending and tax incentives on clean energy provisions. Most notably, the IRA includes provisions that extend and expand the production and investment tax credits for wind and solar; includes energy storage, EVs, RNG, and carbon capture and sequestration; and allows for the transferability of clean energy tax credits on existing and qualifying new facilities. We see the IRA as generally supportive of our Energy Transition strategy with the potential to drive increased value for our customers and shareholders. We are still evaluating the impacts of the IRA provisions on our future capital projects.

Deliver a competitive total return to investors and maintain an investment grade credit rating. We are proud of our track record of annual dividend increases for shareholders. 2023 represented our 53rd consecutive year of increasing dividends. In January 2024, our Board of Directors declared a quarterly dividend of $0.65 per share, equivalent to an annual dividend of $2.60 per share. We intend to continue our record of annual dividend increases with a targeted dividend payout ratio of 55% to 65% of net income.

We require access to the capital markets to fund our planned capital investments or acquire strategic assets that support prudent and earnings-accretive business growth. We have demonstrated our ability to cost-effectively access the debt and equity markets, while maintaining our investment-grade issuer credit rating.

Recent Developments

Macroeconomic Trends

We continue to monitor challenging macroeconomic trends including supply chain disruptions, rising interest rates, potential recession and inflationary pressures on the prices of materials, outside services and employee costs. To date, we have experienced moderate net impacts from these trends. However, if current macroeconomic conditions deteriorate in 2024, adverse impacts to our businesses may be magnified.

Inflation has increased our operating expenses, which included higher employee-related expenses in 2023 compared to the prior year.

We are proactively managing increased costs of materials and supply chain disruptions to achieve our forecasted capital investment targets. To support our 2024 capital investment program, we have contracts in place with key suppliers and we have contracted services for a significant portion of our largest forecasted projects. We continue to forecast multi-year key material requirements with suppliers to enhance predictable material availability, challenge vendor price increases to ensure best value and cost transparency and invest in our distribution network to ensure the safety and reliability of our system. We have also evaluated each of our forecasted projects and will prioritize them depending on future constraints. Project delays may occur if costs rise significantly or if materials are not available.

Rising interest rates have led to increased interest expense on recent debt issuances. These impacts were partially offset by lower short-term, variable rate borrowings and higher interest income on our cash equivalents when compared to the prior year.

The deflationary trend in commodity prices throughout 2023 has partially offset macroeconomic headwinds from inflation and higher interest rates. Lower commodity prices have led to lower customer bills, lower cost of fuel, purchased power and natural gas sold, and improved cash flows from operations due to recoveries of deferred energy costs from customers (which were elevated at the end of 2022 and subsequently collected in 2023).

More detailed discussion of the future uncertainties can be found in Item 1A - Risk Factors.

Business Segment Highlights and Corporate Activity

Electric Utilities

- See Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for recent rate review activity for Wyoming Electric.

- See Key Elements of our Business Strategy section above for discussion of recent developments related to Ready Wyoming, Colorado Electric's Clean Energy Plan, and South Dakota Electric and Wyoming Electric's IRP.

- On January 11, 2024, Wyoming Electric set a new winter peak load of 314 MW, surpassing the previous winter peaks of 301 MW set on December 26, 2023, 299 MW set on October 31, 2023, and 281 MW set in December 2022.

- On July 24, 2023, Wyoming Electric set a new all-time and summer peak load of 312 MW, surpassing the previous peak of 294 MW set on July 21, 2022.

Gas Utilities

- See Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for recent rate review activity for Arkansas Gas, Colorado Gas, RMNG and Wyoming Gas.

- See Key Elements of our Business Strategy section above for discussion of recent developments related to BHERR's purchase of a RNG production facility in Iowa.

Corporate and Other

- On September 15, 2023, we completed a public debt offering of $450 million, 6.15% 10-year senior unsecured notes due May 15, 2034. Net proceeds from the offering were used to repay our $525 million principal amount outstanding notes and for other general corporate purposes. See Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for further information.

- On June 16, 2023, we filed a new shelf registration statement with the SEC and entered into a new Equity Distribution Sales Agreement. The new Equity Distribution Sales Agreement is similar to our prior agreement and allows us to sell shares of common stock up to an aggregate of $400 million through our ATM program utilizing our shelf registration statement. As of December 31, 2023, we have $329 million available to issue under this program. See Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for further information.

- On March 7, 2023, we completed a public debt offering of $350 million, 5.95% 5-year senior unsecured notes due March 15, 2028. The proceeds from the offering were used to repay notes outstanding under our commercial paper program and for other general corporate purposes. See Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for further information.

Results of Operations

Our discussion and analysis for the year ended December 31, 2023, compared to 2022 is included herein. For discussion and analysis for the year ended December 31, 2022, compared to 2021, please refer to Item 7 of Part II, "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report on Form 10-K for the year ended December 31, 2022, which was filed with the SEC on February 14, 2023.

All amounts are presented on a pre-tax basis unless otherwise indicated. Minor differences in amounts may result due to rounding.

Consolidated Summary and Overview

	For the Years Ended December 31,				
	2023	2022	2023 vs 2022 Variance	2021	2022 vs 2021 Variance
	(in millions, except per share amounts)				
Operating income (loss):					
Electric Utilities	$ 248.8	$ 214.3	$ 34.5	$ 202.7	$ 11.6
Gas Utilities	228.8	244.2	(15.4)	211.2	33.0
Corporate and Other [(a)]	(4.9)	(3.3)	(1.6)	(4.5)	1.2
Operating Income	472.7	455.2	17.5	409.4	45.8
Interest expense, net	(167.9)	(161.0)	(6.9)	(152.4)	(8.6)
Other income (expense), net	(3.2)	1.8	(5.0)	1.4	0.4
Income tax (expense)	(25.6)	(25.2)	(0.4)	(7.2)	(18.0)
Net income	276.0	270.8	5.2	251.3	19.5
Net income attributable to non-controlling interest	(13.8)	(12.4)	(1.4)	(14.5)	2.1
Net income available for common stock	$ 262.2	$ 258.4	$ 3.8	$ 236.7	$ 21.7
Total earnings per share of common stock, Diluted	$ 3.91	$ 3.97	$ (0.06)	$ 3.74	$ 0.23

(a) Includes inter-segment eliminations.

2023 Compared to 2022

The variance to the prior year included the following:

- Electric Utilities' operating income increased $34.5 million primarily due to new rates and rider recovery, a one-time gain on the planned sale of Northern Iowa Windpower assets, a gain on a strategic sale of land in Wyoming to a customer to support continued load growth, and a one-time recovery from our business interruption insurance related to the 2021 Wygen I unplanned outage partially offset by unfavorable weather, higher depreciation expense and higher employee-related expenses;
- Gas Utilities' operating income decreased $15.4 million primarily due to unfavorable weather, a prior year one-time true-up of carrying costs accrued on Winter Storm Uri regulatory assets and higher operating expenses partially offset by new rates and rider recovery and retail customer growth and demand;
- Interest expense increased $6.9 million due to higher interest rates partially offset by increased interest income on higher cash and cash equivalents balances; and
- Other expense, net increased $5.0 million primarily due to higher benefit plan non-service costs driven by higher discount rates and higher costs for our non-qualified deferred compensation plan driven by market performance.

Segment Operating Results

Non-GAAP Financial Measure

The following discussion includes financial information prepared in accordance with GAAP, as well as another financial measure, Electric and Gas Utility margin, that is considered a "non-GAAP financial measure." Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. Electric and Gas Utility margin (revenue less cost of sales) is a non-GAAP financial measure due to the exclusion of operation and maintenance expenses, depreciation and amortization expenses, and property and production taxes from the measure.

Electric Utility margin is calculated as operating revenue less cost of fuel and purchased power. Gas Utility margin is calculated as operating revenue less cost of natural gas sold. Our Electric and Gas Utility margin is impacted by the fluctuations in power and natural gas purchases and other fuel supply costs. However, while these fluctuating costs impact Electric and Gas Utility margin as a percentage of revenue, they only impact total Electric and Gas Utility margin if the costs cannot be passed through to our customers.

Our Electric and Gas Utility margin measure may not be comparable to other companies' Electric and Gas Utility margin measures. Furthermore, this measure is not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance.

Electric Utilities

Operating results for the years ended December 31 for the Electric Utilities were as follows (in millions):

	2023	2022	2023 vs 2022 Variance	2021	2022 vs 2021 Variance
Revenue:					
Electric - regulated	$ 817.4	$ 852.2	$ (34.8)	$ 800.7	$ 51.5
Other - non-regulated	47.6	48.0	(0.4)	41.5	6.5
Total revenue	865.0	900.2	(35.2)	842.2	58.0
Fuel and Purchased Power:					
Electric - regulated	198.3	261.7	(63.4)	244.5	17.2
Other - non-regulated	1.8	4.6	(2.8)	3.5	1.1
Total fuel and purchased power	200.1	266.3	(66.2)	248.0	18.3
Electric Utility margin (non-GAAP)	664.9	633.9	31.0	594.2	39.7
Operations and maintenance	236.2	244.8	(8.6)	224.5	20.3
Depreciation and amortization	142.6	135.9	6.7	131.5	4.4
Taxes - property and production	37.3	38.9	(1.6)	35.5	3.4
	416.1	419.6	(3.5)	391.5	28.1
Operating income	$ 248.8	$ 214.3	$ 34.5	$ 202.7	$ 11.6

2023 Compared to 2022

Electric Utility margin increased over the prior year as a result of:

	(in millions)
New rates and rider recovery	$ 29.4
Wygen I revenue recovery under business interruption insurance [(a)]	5.0
Integrated Generation [(b)]	3.3
Transmission services	3.2
Weather	(6.2)
Retail customer usage	(4.4)
Other	0.7
	$ 31.0

(a) In 2021, Wygen I experienced an unplanned outage which resulted in lost revenue. A claim for these losses was submitted under our business interruption insurance policy. During the third quarter of 2023, we recovered $5.0 million from our business interruption insurance which was recognized as Revenue. See Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for further information.
(b) Primarily driven by favorable mining contract pricing and increased Black Hills Colorado IPP fired-engine hours.

Operations and maintenance expense decreased primarily due to a one-time $7.7 million gain on the planned sale of Northern Iowa Windpower assets, a $3.9 million gain on a strategic sale of land in Wyoming to a customer to support continued load growth, and $2.9 million of lower outside services expenses partially offset by $8.7 million of higher employee-related expenses.

Depreciation and amortization increased primarily due to higher asset base driven by prior and current year capital expenditures.

Taxes - property and production were comparable to the same period in the prior year.

Operating Statistics

	Revenue (in millions)			Quantities Sold (GWh)		
For the year ended December 31,	**2023**	**2022**	**2021**	**2023**	**2022**	**2021**
Residential	$ 224.9	$ 246.7	$ 244.6	1,438.5	1,513.1	1,494.0
Commercial	259.8	277.9	276.0	2,074.4	2,087.8	2,075.7
Industrial	159.4	166.4	149.0	2,094.8	1,912.5	1,751.4
Municipal	17.5	20.5	19.1	150.9	159.3	162.9
Subtotal Retail Revenue - Electric	661.6	711.5	688.7	5,758.6	5,672.7	5,484.0
Contract Wholesale	22.0	25.9	16.1	579.1	654.0	574.1
Off-system/Power Marketing Wholesale	42.5	48.6	41.7	737.9	643.2	638.9
Other [(a)]	91.2	66.2	54.2	-	-	-
Total Regulated	817.3	852.2	800.7	7,075.6	6,969.9	6,697.0
Non-Regulated [(b)]	47.7	48.0	41.5	120.6	293.0	269.6
Total Revenue and Quantities Sold	$ 865.0	$ 900.2	$ 842.2	7,196.2	7,262.9	6,966.6
Other Uses, Losses or Generation, net [(c)]				463.5	450.0	475.3
Total Energy				7,659.7	7,712.9	7,441.9

(a) Primarily related to transmission revenues from the Common Use System.
(b) Includes Integrated Generation and non-regulated services to our retail customers under the Service Guard Comfort Plan and Tech Services.
(c) Includes company uses and line losses.

	Revenue (in millions)			Quantities Sold (GWh)		
For the year ended December 31,	**2023**	**2022**	**2021**	**2023**	**2022**	**2021**
Colorado Electric	$ 285.7	$ 321.1	$ 302.9	2,397.2	2,440.0	2,574.0
South Dakota Electric	321.1	335.2	319.4	2,554.3	2,626.2	2,389.4
Wyoming Electric	212.2	197.7	180.4	2,124.1	1,903.7	1,733.6
Integrated Generation	46.0	46.2	39.5	120.6	293.0	269.6
Total Revenue and Quantities Sold	$ 865.0	$ 900.2	$ 842.2	7,196.2	7,262.9	6,966.6

	For the year ended December 31,		
Quantities Generated and Purchased by Fuel Type (GWh)	**2023**	**2022**	**2021**
Generated:			
Coal	2,683.4	2,708.8	2,546.9
Natural Gas	2,021.4	1,454.2	1,817.2
Wind [(a)]	678.5	875.8	842.6
Total Generated	5,383.3	5,038.8	5,206.7
Purchased:			
Coal, Natural Gas, Diesel Oil and Other Market Purchases	1,842.9	2,280.8	1,866.4
Wind and Solar	433.5	393.3	368.8
Total Purchased	2,276.4	2,674.1	2,235.2
Total Generated and Purchased	7,659.7	7,712.9	7,441.9

(a) Wind generation decreased due to the sale of Northern Iowa Windpower assets in March 2023.

	For the year ended December 31,		
Quantities Generated and Purchased (GWh)	**2023**	**2022**	**2021**
Generated:			
Colorado Electric	653.9	474.4	412.1
South Dakota Electric	2,018.5	1,890.0	1,980.7
Wyoming Electric	908.3	905.8	883.6
Integrated Generation	1,802.5	1,768.6	1,842.4
Total Generated	5,383.2	5,038.8	5,118.8
Purchased:			
Colorado Electric	588.2	1,005.4	1,027.7
South Dakota Electric	604.6	826.4	563.6
Wyoming Electric	1,028.5	757.2	643.9
Integrated Generation	55.2	85.1	87.9
Total Purchased	2,276.5	2,674.1	2,323.1
Total Generated and Purchased	7,659.7	7,712.9	7,441.9

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Degree Days	For the year ended December 31, 2023 Actual	Variance from Normal	2022 Actual	Variance from Normal	2021 Actual	Variance from Normal
Heating Degree Days:						
Colorado Electric	5,330	1%	5,551	9%	5,023	(11)%
South Dakota Electric	6,969	(4)%	7,495	6%	6,819	(5)%
Wyoming Electric	6,783	(1)%	7,051	3%	6,702	(6)%
Combined [(a)]	6,185	(1)%	6,518	6%	5,974	(7)%
Cooling Degree Days:						
Colorado Electric	1,046	(10)%	1,362	9%	1,245	39%
South Dakota Electric	497	(21)%	814	27%	827	30%
Wyoming Electric	329	(30)%	701	47%	604	74%
Combined [(a)]	713	(15)%	1,040	18%	973	40%

(a) Degree days are calculated based on a weighted average of total customers by state.

Contracted generating facilities availability by fuel type [(a)]	For the year ended December 31, 2023	2022	2021
Coal	93.7%	91.5%	86.7%
Natural gas and diesel oil	92.1%	96.1%	95.5%
Wind	92.5%	93.7%	95.8%
Total availability	92.6%	94.4%	93.2%
Wind Capacity Factor	37.4%	34.7%	34.0%

(a) Availability and Wind Capacity Factor are calculated using a weighted average based on capacity of our generating fleet.

Gas Utilities

Operating results for the years ended December 31 for the Gas Utilities were as follows (in millions):

	2023	2022	2023 vs 2022 Variance	2021	2022 vs 2021 Variance
Revenue:					
Natural gas - regulated	$ 1,399.1	$ 1,584.6	$ (185.5)	$ 1,051.6	$ 533.0
Other - non-regulated services	85.1	84.5	0.6	73.3	11.2
Total revenue	1,484.2	1,669.1	(184.9)	1,124.9	544.2
Cost of natural gas sold:					
Natural gas - regulated	760.2	942.1	(181.9)	480.3	461.8
Other - non-regulated services	23.0	23.0	—	14.4	8.6
Total cost of natural gas sold	783.2	965.1	(181.9)	494.7	470.4
Gas Utility margin (non-GAAP)	701.0	704.0	(3.0)	630.2	73.8
Operations and maintenance	328.7	317.3	11.4	290.2	27.1
Depreciation and amortization	113.9	114.7	(0.8)	104.2	10.5
Taxes - property and production	29.6	27.8	1.8	24.6	3.2
	472.2	459.8	12.4	419.0	40.8
Operating income	$ 228.8	$ 244.2	$ (15.4)	$ 211.2	$ 33.0

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2023 Compared to 2022

Gas Utility margin decreased over the prior year as a result of:

	(in millions)
New rates and rider recovery	$ 19.8
Retail customer growth and demand	7.6
Weather	(14.5)
Prior year true-up of Winter Storm Uri carrying costs [a]	(10.3)
Mark-to-market on non-utility natural gas commodity contracts	(3.5)
Other	(2.1)
	$ (3.0)

(a) In certain jurisdictions, we have commission approval to recover carrying costs on Winter Storm Uri regulatory assets which offset increased interest expense. Additionally, the carrying costs accrued during the year ended December 31, 2022 included a one-time, $10.3 million true-up to reflect commission authorized rates.

Operations and maintenance expense increased primarily due to $14.8 million of higher employee-related expenses partially offset by $5.0 million of lower outside services expenses.

Depreciation and amortization was comparable to the prior year.

Taxes - property and production were comparable to the prior year.

Operating Statistics

	Revenue (in millions)			Quantities Sold and Transported (Dth in millions)		
	For the year ended December 31,			For the year ended December 31,		
	2023	2022	2021	2023	2022	2021
Residential	$ 839.2	$ 940.2	$ 613.5	60.1	66.9	60.1
Commercial	340.1	398.6	242.1	29.4	32.4	29.1
Industrial	33.2	63.0	33.4	5.7	7.7	6.2
Other	9.1	8.7	3.8	—	—	—
Total Distribution	1,221.6	1,410.5	892.8	95.2	107.0	95.4
Transportation and Transmission	177.5	174.1	158.8	159.8	160.9	154.6
Total Regulated	1,399.1	1,584.6	1,051.6	255.0	267.9	250.0
Non-regulated Services [a]	85.1	84.5	73.3	—	—	—
Total Revenue and Quantities Sold	$ 1,484.2	$ 1,669.1	$ 1,124.9	255.0	267.9	250.0

(a) Includes Black Hills Energy Services and non-regulated services under the Service Guard Comfort Plan, Tech Services and HomeServe.

	Revenue (in millions)			Quantities Sold and Transported (Dth in millions)		
	For the year ended December 31,			For the year ended December 31,		
	2023	2022	2021	2023	2022	2021
Arkansas Gas	$ 268.9	$ 311.3	$ 218.5	30.2	32.3	31.5
Colorado Gas	313.6	320.9	208.0	32.8	34.3	32.3
Iowa Gas	213.6	283.9	171.7	37.9	40.9	38.0
Kansas Gas	155.6	191.4	121.6	35.5	38.6	34.5
Nebraska Gas	366.1	384.8	273.4	82.2	85.1	81.0
Wyoming Gas	166.4	176.8	131.7	36.4	36.7	32.7
Total Revenue and Quantities Sold	$ 1,484.2	$ 1,669.1	$ 1,124.9	255.0	267.9	250.0

	For the year ended December 31,					
	2023		2022		2021	
Heating Degree Days	Actual	Variance From Normal	Actual	Variance From Normal	Actual	Variance From Normal
Arkansas Gas [(a)]	3,197	(17)%	3,844	2%	3,565	(12)%
Colorado Gas	5,916	(4)%	6,325	4%	5,866	(11)%
Iowa Gas	5,921	(12)%	7,037	7%	6,239	(8)%
Kansas Gas [(a)]	4,387	(8)%	4,968	7%	4,508	(8)%
Nebraska Gas	5,579	(8)%	6,220	4%	5,599	(9)%
Wyoming Gas	7,385	8%	7,644	12%	7,074	(7)%
Combined [(b)]	6,006	(4)%	6,536	5%	5,948	(8)%

(a) Arkansas and Kansas have weather normalization mechanisms that mitigate the weather impact on Gas Utility margins.
(b) Heating degree days are calculated based on a weighted average of total customers by state excluding Kansas due to its weather normalization mechanism. Arkansas Gas is partially excluded based on the weather normalization mechanism in effect from November through April.

Corporate and Other

Corporate and Other operating results, including inter-segment eliminations, for the years ended December 31 were as follows:

(in millions)	2023	2022	2023 vs 2022 Variance	2021	2022 vs 2021 Variance
Operating (loss)	$ (4.9)	$ (3.3)	$ (1.6)	$ (4.5)	$ 1.2

2023 Compared to 2022

Operating (loss) was comparable to the prior year.

Consolidated Interest Expense, Other Income (Expense) and Income Tax (Expense)

(in millions)	2023	2022	2023 vs 2022 Variance	2021	2022 vs 2021 Variance
Interest expense, net	$ (167.9)	$ (161.0)	$ (6.9)	$ (152.4)	$ (8.6)
Other income (expense), net	(3.2)	1.8	(5.0)	1.4	0.4
Income tax (expense)	(25.6)	(25.2)	(0.4)	(7.2)	(18.0)

2023 Compared to 2022

Interest expense, net increased due to higher interest rates partially offset by increased interest income on higher cash and cash equivalents balances.

Other (expense), net increased primarily due to higher benefit plan non-service costs driven by higher discount rates and higher costs for our non-qualified deferred compensation plan which were driven by market performance.

Income tax (expense) and the effective tax rate were comparable to the same period in the prior year. The effective tax rate was 8.5% for both 2023 and 2022. The effective tax rate was comparable primarily due to a $8.2 million tax benefit from a current year Nebraska income tax rate decrease offset by $6.5 million of lower tax benefits from various current and prior year state tax rate changes and $3.6 million of lower wind PTCs resulting from the March 2023 sale of Northern Iowa Windpower assets. See Note 15 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional details.

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Liquidity and Capital Resources

OVERVIEW

Our company requires significant cash to support and grow our businesses. Our primary sources of cash are generated from our operating activities, Revolving Credit Facility, CP Program, ATM and ability to access the public and private capital markets through debt and equity securities offerings when necessary. This cash is used for, among other things, working capital, capital expenditures, dividends, pension funding, investments in or acquisitions of assets and businesses, payment of debt obligations and redemption of outstanding debt and equity securities when required or financially appropriate.

We experience significant cash requirements during peak months of the winter heating season due to higher natural gas consumption, during periods of high natural gas prices, and during the construction season, which typically peaks in spring and summer.

We believe that our cash on hand, operating cash flows, existing borrowing capacity and ability to complete new debt and equity financings, taken in their entirety, provide sufficient capital resources to fund our ongoing operating requirements, regulatory liabilities, debt maturities, anticipated dividends, and anticipated capital expenditures discussed in this section.

The following table provides an informational summary of our liquidity and capital structure as of December 31 (dollars in millions):

	2023	2022
Cash and cash equivalents	$ 86.6	$ 21.4
Available capacity under Revolving Credit Facility and CP Program [a]	746.3	189.8
Available liquidity	$ 832.9	$ 211.2
Capital structure		
Short-term debt	$ 600.0	$ 1,060.6
Long-term debt	3,801.2	3,607.3
Total debt	4,401.2	4,667.9
Total stockholders' equity (excludes non-controlling interest)	3,215.3	2,994.9
Total capitalization	$ 7,616.5	$ 7,662.8
Debt to capitalization	57.8 %	60.9 %
Net debt to capitalization [b]	57.3 %	60.8 %
Long-term debt to total debt	86.4 %	77.3 %

(a) Available capacity under Revolving Credit Facility and CP Program represents $750 million of total borrowing capacity less outstanding borrowings and letters of credit. See Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for more information.

(b) Net debt to capitalization ratio is net of Cash and cash equivalents for both Total debt and Total capitalization.

CASH FLOW ACTIVITIES

The following tables summarize our cash flows for the years ended December 31 (in millions):

Operating Activities:

	2023	2022	2023 vs 2022	2021	2022 vs 2021
Net income	$ 276.0	$ 270.8	$ 5.2	$ 251.2	$ 19.6
Non-cash adjustments to Net income	313.5	295.7	17.8	276.6	19.1
Total earnings	589.5	566.5	23.0	527.8	38.7
Changes in certain operating assets and liabilities:					
Accounts receivable and other current assets	255.9	(259.9)	515.8	(78.9)	(181.0)
Accounts payable and accrued liabilities	(109.9)	89.4	(199.3)	10.6	78.8
Regulatory assets and liabilities	236.8	203.9	32.9	(524.2)	728.1
Net inflow (outflow) from changes in certain operating assets and liabilities	382.8	33.4	349.4	(592.5)	625.9
Other operating activities	(27.9)	(15.1)	(12.8)	0.1	(15.2)
Net cash provided by (used in) operating activities	$ 944.4	$ 584.8	$ 359.6	$ (64.6)	$ 649.4

2023 Compared to 2022

Net cash provided by operating activities was $359.6 million higher which was attributable to:

- Total earnings (net income plus non-cash adjustments) were $23.0 million higher than prior year primarily as a result of increased Electric and Gas Utility margins due to new rates and increased rider revenues partially offset by higher operating expenses and higher interest expense.
- Net inflows from changes in certain operating assets and liabilities were $349.4 million higher than prior year, primarily attributable to:
  - Cash inflows increased by approximately $515.8 million as a result of changes in accounts receivable and other current assets primarily due to higher collections on pass-through revenues and lower natural gas in storage inventories driven by fluctuations in commodity prices and timing of injections and withdrawals;
  - Cash outflows increased by approximately $199.3 million as a result of decreases in accounts payable and other current liabilities primarily driven by fluctuations in commodity prices, payment timing of natural gas and power purchases and changes in other working capital requirements; and
  - Cash inflows increased by approximately $32.9 million as a result of changes in our regulatory assets and liabilities primarily due to higher recoveries of deferred gas and fuel cost adjustments driven by fluctuations in commodity prices.
- Cash outflows increased $12.8 million from other operating activities primarily due to higher costs from cloud computing arrangements.

Investing Activities:

	2023	2022	2023 vs 2022	2021	2022 vs 2021
Capital expenditures	$ (555.6)	$ (604.4)	$ 48.8	$ (677.5)	$ 73.1
Other investing activities	18.9	0.5	18.4	13.3	(12.8)
Net cash (used in) investing activities	$ (536.7)	$ (603.9)	$ 67.2	$ (664.2)	$ 60.3

2023 Compared to 2022

Net cash used in investing activities was $67.2 million lower which was attributable to:

- Cash outflows from capital expenditures (which are net of $33.8 million contributions in aid of construction) decreased $48.8 million as a result of lower programmatic safety, reliability and integrity spending at our Gas and Electric Utilities and higher receipts related to contributions in aid of construction driven by strategic projects in Wyoming;
- Cash inflows increased $18.4 million for other investing activities primarily due to proceeds from the sale of Northern Iowa Windpower assets and the strategic sale of land in Wyoming.

Financing Activities:

	2023	2022	2023 vs 2022	2021	2022 vs 2021
Dividends paid on common stock	$ (168.1)	$ (156.7)	$ (11.4)	$ (145.0)	$ (11.7)
Common stock issued	118.3	90.1	28.2	119.0	(28.9)
Short-term and long-term debt (repayments), net	(260.6)	115.4	(376.0)	777.7	(662.3)
Distributions to non-controlling interests	(18.3)	(17.4)	(0.9)	(15.7)	(1.7)
Other financing activities	(13.0)	0.9	(13.9)	(4.1)	5.0
Net cash provided by (used in) financing activities	$ (341.7)	$ 32.3	$ (374.0)	$ 731.9	$ (699.6)

2023 Compared to 2022

Net cash used in financing activities was $374.0 million higher which was primarily attributable to:

- Cash outflows increased $11.4 million due to increased dividends paid on common stock;
- Cash inflows increased $28.2 million due to higher issuances of common stock;

- Net outflows from changes in short-term and long-term debt (repayments) borrowings increased $376.0 million due to:
    - Cash outflows increased $651.0 million as a result of net repayment activity under our Revolving Credit Facility and CP Program;
    - Cash outflow of $525.0 million due to repayment of our senior unsecured notes on their November 30, 2023 maturity date; and
    - Cash inflow of $800.0 million from the March 7, 2023 and September 15, 2023 debt offerings.
- Cash outflows increased by $13.9 million for other financing activities primarily due to financing costs from the March 7, 2023 and September 15, 2023 debt offerings.

CAPITAL RESOURCES

Shelf Registration Statement

We maintain an effective shelf registration statement with the SEC under which we may issue, from time to time, an unspecified amount of senior debt securities, subordinate debt securities, common stock, preferred stock, warrants and other securities. See Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for recent updates regarding our shelf registration statement.

Short-term Debt

We have a $750 million Revolving Credit Facility that matures on July 19, 2026, with two one-year extension options (subject to consent from lenders). This facility includes an accordion feature that allows us to increase total commitments up to $1.0 billion with the consent of the administrative agent, the issuing agents and each bank increasing or providing a new commitment. We also have a $750 million, unsecured CP Program that is backstopped by the Revolving Credit Facility. Amounts outstanding under the Revolving Credit Facility and the CP Program, either individually or in the aggregate, cannot exceed $750 million.

The Revolving Credit Facility prohibits us from paying cash dividends if a default or an event of default exists prior to, or would result after, paying a dividend. Although these contractual restrictions exist, we do not anticipate triggering any default measures or restrictions.

The Revolving Credit Facility contains cross-default provisions that could result in a default under such agreements if BHC or its material subsidiaries failed to 1) make timely payments of debt obligations; or 2) triggered other default provisions under any debt agreement totaling, in the aggregate principal amount of $50 million or more that permit the acceleration of debt maturities or mandatory debt prepayment.

See Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for more information on our Revolving Credit Facility and CP Program.

Utility Money Pool

As a utility holding company, we are required to establish a cash management program to address lending and borrowing activities between our utilities and the Company. We have established utility money pool agreements which address these requirements. These agreements are on file with the FERC and appropriate state regulators. Under the utility money pool agreements, our utilities may, at their option, borrow and extend short-term loans to the utility money pool at market-based rates. While the utility money pool may borrow funds from the Company (as ultimate parent company), the money pool arrangement does not allow loans from our utility subsidiaries to the Company (as ultimate parent company) or to non-regulated affiliates.

Long-term Debt

For information on our long-term debt, see Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Covenant Requirements

The Revolving Credit Facility and Wyoming Electric’s financing agreements contain covenant requirements. We were in compliance with these covenants as of December 31, 2023. See additional information in Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Equity

For information regarding equity, see Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Future Financing Plans

We will continue to assess debt and equity needs to support our capital investment plans and other strategic objectives. We plan to fund our capital plan and strategic objectives by using cash generated from operating activities and various financing alternatives, which could include our Revolving Credit Facility, our CP Program, debt offerings, the issuance of common stock under our ATM program or in an opportunistic block trade. We also plan to re-finance our $600 million, 1.0375%, senior unsecured notes due August 2024, at or before maturity date.

CREDIT RATINGS

Financing for operational needs and capital expenditure requirements, not satisfied by operating cash flows, depends upon the cost and availability of external funds through both short and long-term financing. In order to operate and grow our business, we need to consistently maintain the ability to raise capital on favorable terms. Access to funds is dependent upon factors such as general economic and capital market conditions, regulatory authorizations and policies, the Company's credit ratings, cash flows from routine operations and the credit ratings of counterparties. After assessing the current operating performance, liquidity and credit ratings of the Company, management believes that the Company will have access to the capital markets at prevailing market rates for companies with comparable credit ratings. We note that credit ratings are not recommendations to buy, sell, or hold securities and may be subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating.

The following table represents the credit ratings, outlook and risk profile of BHC at December 31, 2023:

Rating Agency	Senior Unsecured Rating	Outlook
S&P [(a)]	BBB+	Stable
Moody's [(b)]	Baa2	Stable
Fitch [(c)]	BBB+	Stable

(a) On February 17, 2023, S&P reported BBB+ rating and maintained a Stable outlook.
(b) On December 21, 2023, Moody's reported our Baa2 rating and maintained a Stable outlook.
(c) On January 26, 2024, Fitch reported BBB+ rating and revised to a Negative outlook.

Certain fees and interest rates under our Revolving Credit Facility are based on our credit ratings at all three rating agencies. If all of our ratings are at the same level, or if two of our ratings are the same level and one differs, these fees and interest rates will be based on the ratings that are at the same level. If all of our ratings are at different levels, these fees and interest rates will be based on the middle level. Currently, our Fitch and S&P ratings are at the same level, and our Moody's rating is one level below. Therefore, if Fitch or S&P downgrades our senior unsecured debt, we will be required to pay higher fees and interest rates under our Revolving Credit Facility.

The following table represents the credit ratings of South Dakota Electric at December 31, 2023:

Rating Agency	Senior Secured Rating
S&P [(a)]	A
Fitch [(b)]	A

(a) On February 17, 2023, S&P reported A rating
(b) On January 26, 2024, Fitch reported A rating

We have not had any triggering events (i.e. an acceleration of repayment of outstanding indebtedness, an increase in interest costs, or the posting of additional cash collateral) tied to our stock price and have not executed any transactions that require us to issue equity based on our credit ratings.

CAPITAL REQUIREMENTS

Capital Expenditures

Capital expenditures are a substantial portion of our cash requirements each year and we continue to forecast a robust capital expenditure program during the next five years. See above in Key Elements of our Business Strategy for forecasted capital expenditure requirements. A significant portion of our capital expenditures are for safety, reliability and integrity of our system and is included in utility rate base and eligible for recovery from our utility customers with regulatory approval. Those capital expenditures also earn a rate of return authorized by the commissions in the jurisdictions in which we operate.

Our historical capital expenditures by reportable segment are shown in Note 16 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Repayments of Indebtedness

For information relating to repayments of our short- and long-term debt and associated interest payments, see Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Unconditional Purchase Obligations

We have unconditional purchase obligations which include the energy and capacity costs associated with our PPAs, transmission services agreements, and natural gas capacity, transportation and storage agreements. Additionally, our Gas Utilities have commitments to purchase physical quantities of natural gas under contracts indexed to various forward natural gas price curves. For additional information. see Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Defined Benefit Pension Plan

We have one defined benefit pension plan, the Black Hills Retirement Plan (Pension Plan). The unfunded status of the Pension Plan is defined as the amount the projected benefit obligation exceeds the plan assets. The unfunded status of the Pension Plan is $39.4 million as of December 31, 2023, compared to $35.2 million as of December 31, 2022. We do not have required contributions, however, we expect to make $2.3 million in contributions to our Pension Plan in 2024. See further information in Note 13 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Common Stock Dividends

Future cash dividends, if any, will be dependent on our results of operations, financial position, cash flows, reinvestment opportunities and other factors, and will be evaluated and approved by our Board of Directors.

Additionally, there are certain statutory limitations that could affect future cash dividends paid. Federal law places limits on the ability of public utilities within a holding company structure to declare dividends. Specifically, under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. The utility subsidiaries' dividends may be limited directly or indirectly by state regulatory commissions or bond indenture covenants. See additional information in Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

On January 26, 2024, our Board of Directors declared a quarterly dividend of $0.65 per share, equivalent to an annual dividend rate of $2.60 per share. The table below provides our dividends paid (in millions), dividend payout ratio and dividends paid per share for the three years ended December 31:

	2023	2022	2021
Common Stock Dividends Paid	$ 168.1	$ 156.7	$ 145.0
Dividend Payout Ratio	64 %	61 %	61 %
Dividends Per Share	$ 2.50	$ 2.41	$ 2.29

Our three-year compound annualized dividend growth rate was 4.8%.

Collateral Requirements

Our Utilities maintain wholesale commodity contracts for the purchases and sales of electricity and natural gas which have performance assurance provisions that allow the counterparty to require collateral postings under certain conditions, including when requested on a reasonable basis due to a deterioration in our financial condition or nonperformance. A significant downgrade in our credit ratings, such as a downgrade to a level below investment grade, could result in counterparties requiring collateral postings under such adequate assurance provisions. The amount of credit support that we may be required to provide at any point in the future is dependent on the amount of the initial transaction, changes in the market price, open positions and the amounts owed by or to the counterparty. At December 31, 2023, we had sufficient liquidity to cover collateral that could be required to be posted under these contracts. The cash collateral we were required to post at December 31, 2023 was not material. See Note 9 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Guarantees

We provide various guarantees, which represent off-balance sheet commitments, supporting certain of our subsidiaries under specified agreements or transactions. For more information on these guarantees, see Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Critical Accounting Estimates

We prepare our consolidated financial statements in conformity with GAAP. In many cases, the accounting treatment of a particular transaction is specifically dictated by GAAP and does not require management's judgment in application. There are also areas which require management's judgment in selecting among available GAAP alternatives. We are required to make certain estimates, judgments and assumptions that we believe are reasonable based upon the information available. We continue to closely monitor the macroeconomic environment and related impacts on our critical accounting estimates including, but not limited to, collectability of customer receivables, recoverability of regulatory assets, impairment risk of goodwill and long-lived assets, and contingent liabilities. These estimates and assumptions affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods presented. Actual results may differ from our estimates and to the extent there are material differences between these estimates, judgments or assumptions and actual results, our financial statements will be affected. We believe the following accounting estimates are the most critical in understanding and evaluating our reported financial results. We have reviewed these critical accounting estimates and related disclosures with our Audit Committee.

The following discussion of our critical accounting estimates should be read in conjunction with Note 1, "Business Description and Significant Accounting Policies" of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Regulation

Our regulated Electric and Gas Utilities are subject to cost-of-service regulation and earnings oversight from federal and state utility commissions. This regulatory treatment does not provide any assurance as to achievement of desired earnings levels. Our retail electric and gas utility rates are regulated on a state-by-state basis by the relevant state regulatory commissions based on an analysis of our costs, as reviewed and approved in a regulatory proceeding. The rates that we are allowed to charge may or may not match our related costs and allowed return on invested capital at any given time.

Management continually assesses the probability of future recoveries associated with regulatory assets and future obligations associated with regulatory liabilities. Factors such as the current regulatory environment, recently issued rate orders and historical precedents are considered. As a result, we believe that the accounting prescribed under rate-based regulation remains appropriate and our regulatory assets are probable of recovery in current rates or in future rate proceedings.

To some degree, each of our Electric and Gas Utilities are permitted to recover certain costs (such as increased fuel and purchased power costs) outside of a base rate review. To the extent we are able to pass through such costs to our customers, and a state regulatory commission subsequently determines that such costs should not have been paid by the customers, we may be required to refund such costs.

As of December 31, 2023 and 2022, we had total regulatory assets of $480.1 million and $653.0 million, respectively, and total regulatory liabilities of $566.6 million and $518.6 million, respectively. See Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for further information.

Goodwill

We perform a goodwill impairment test on an annual basis or upon the occurrence of events or changes in circumstances that indicate that the asset might be impaired. Our annual goodwill impairment testing date is as of October 1, which aligns with our financial planning process.

Accounting standards for testing goodwill for impairment require the application of either a qualitative or quantitative assessment to analyze whether or not goodwill has been impaired. Goodwill is tested for impairment at the reporting unit level. Under either the qualitative or quantitative assessment, the estimated fair value of a reporting unit is compared with its carrying amount, including goodwill. If the carrying amount exceeds fair value, then an impairment loss would be recognized in an amount equal to that excess, limited to the amount of goodwill allocated to that reporting unit.

Application of the goodwill impairment test requires judgment, including the identification of reporting units and determining the fair value of the reporting unit. We have determined that the reporting units for goodwill impairment testing are our operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which the CODM regularly reviews the operating results. We estimate the fair value of our reporting units using a combination of an income approach, which estimates fair value based on discounted future cash flows, and a market approach, which estimates fair value based on market comparables within the utility and energy industries. These valuations require significant judgments, including, but not limited to: 1) estimates of future cash flows, based on our internal five-year business plans and adjusted as appropriate for our view of market participant assumptions, with long range cash flows estimated using a terminal value calculation; 2) estimates of long-term growth rates for our businesses; 3) the determination of an appropriate weighted-average cost of capital or discount rate; and 4) the utilization of market information such as recent sales transactions for comparable assets within the utility and energy industries. Varying by reporting unit, weighted average cost of capital in the range of 6.9% to 7.3% and long-term growth rate projections of 1.75% were utilized in the goodwill impairment test performed as of October 1, 2023. Although 1.75% was used for a long-term growth rate projection, the short-term projected growth rate is higher with planned recovery of capital investments through rider mechanisms and rate reviews. Under the market approach, we estimate fair value using multiples derived from comparable sales transactions and enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, we add a reasonable control premium when calculating fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants.

The estimates and assumptions used in our impairment assessments are based on available market information and we believe they are reasonable. However, variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated.

For the years ended December 31, 2023, 2022, and 2021, there were no impairment losses recorded. At December 31, 2023, the fair value exceeded the carrying value at all reporting units.

See Item 1A - Risk Factors and Note 1 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

Income Taxes

The Company and its subsidiaries file consolidated federal income tax returns. Each entity records income taxes as if it were a separate taxpayer for both federal and state income tax purposes and consolidating adjustments are allocated to the subsidiaries based on separate company computations of taxable income or loss.

The Company uses the asset and liability method in accounting for income taxes. Under the asset and liability method, deferred income taxes are recognized at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities as well as operating loss and tax credit carryforwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements.

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. If we determine that we will be unable to realize all or part of our deferred tax assets in the future, an adjustment to the deferred tax asset would be made in the period such determination was made. These adjustments may increase or decrease earnings. Although we believe our assumptions, judgments and estimates are reasonable, changes in tax laws or our interpretations of tax laws and the resolution of current and any future tax audits could significantly impact the amounts provided for income taxes in our consolidated financial statements.

See Note 15 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our activities in the regulated and non-regulated energy industries expose us to a number of risks in the normal operations of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk.

Market risk is the potential loss that may occur as a result of an adverse change in market price, rate or supply. We are exposed, but not limited to, the following market risks:

- Commodity price risk associated with our retail natural gas services, wholesale electric power marketing activities and fuel procurement for several of our gas-fired generation assets. Market fluctuations may occur due to unpredictable factors such as the COVID-19 pandemic, weather (e.g. Winter Storm Uri), geopolitical events, market speculation, recession, inflation, pipeline constraints, and other factors that may impact natural gas and electric energy supply and demand; and
- Interest rate risk associated with future debt, including reduced access to liquidity during periods of extreme capital markets volatility, such as the 2008 financial crisis and the COVID-19 pandemic.

Credit risk is associated with financial loss resulting from non-performance of contractual obligations by a counterparty.

To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures. The Black Hills Corporation Risk Policies and Procedures have been approved by our Executive Risk Committee. These policies relate to numerous matters including governance, control infrastructure, authorized commodities and trading instruments, prohibited activities and employee conduct. We report any issues or concerns pertaining to the Risk Policies and Procedures to the Audit Committee of our Board of Directors. The Executive Risk Committee, which includes senior level executives, meets at least quarterly and as necessary, to review our business and credit activities and to ensure that these activities are conducted within the authorized policies.

Commodity Price Risk

Electric and Gas Utilities

Our utilities have various provisions that allow them to pass the prudently-incurred cost of energy through to the customer. To the extent energy prices are higher or lower than amounts in our current billing rates, adjustments are made on a periodic basis to reflect billed amounts to match the actual energy cost we incurred. In Colorado, South Dakota and Wyoming, we have ECA or PCA provisions that adjust electric rates when energy costs are higher or lower than the costs included in our tariffs. In Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming, we have GCA provisions that adjust natural gas rates when our natural gas costs are higher or lower than the energy cost included in our tariffs. These adjustments are subject to periodic prudence reviews by the state regulatory commissions. If state regulatory commissions decide to discontinue these tariff-based adjustment mechanisms, or there are delays in the timing of recovery under these mechanisms, we may be more exposed to commodity price risk.

The operations of our utilities, including natural gas sold by our Gas Utilities and natural gas used by our Electric Utilities' generation plants or those plants under PPAs where our Electric Utilities must provide the generation fuel (tolling agreements), expose our utility customers to natural gas price volatility. Therefore, as allowed or required by state regulatory commissions, we have entered into commission-approved hedging programs utilizing natural gas futures, options, over-the-counter swaps and basis swaps to reduce our customers' underlying exposure to these fluctuations.

For our regulated Utilities' hedging plans, unrealized and realized gains and losses, as well as option premiums and commissions on these transactions are recorded as Regulatory assets or Regulatory liabilities in the accompanying Consolidated Balance Sheets in accordance with the state utility commission guidelines. When the related costs are recovered through our rates, the hedging activity is recognized in the Consolidated Statements of Income. See additional information in Note 9 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Wholesale Power

We periodically have wholesale power purchase and sale contracts used to manage purchased power costs and load requirements associated with serving our electric customers that are considered derivative instruments and do not qualify for the normal purchase and normal sales exception for derivative accounting. Changes in the fair value of these commodity derivatives are recognized in the Consolidated Statements of Income.

There is a potential risk that our wholesale power sales could exceed our current generating capacity, which may arise from unplanned plant outages or from unanticipated load demands. To manage such risk, we restrict wholesale off-system sales to amounts by which our anticipated generating capabilities and purchased power resources exceed our anticipated load requirements plus a required reserve margin.

Black Hills Energy Services

To support our Choice Gas Program customers, we buy and sell natural gas at competitive prices by managing commodity price risk. As a result of these activities, this area of our business is exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks using over-the-counter and exchange traded options and swaps with counterparties in anticipation of forecasted purchases and sales. A portion of our over-the-counter swaps have been designated as cash flow hedges to mitigate the commodity price risk associated with fixed price forward contracts to supply gas to our Choice Gas Program customers. The gain or loss on these designated derivatives is reported in AOCI in the accompanying Consolidated Balance Sheets and reclassified into earnings in the same period that the underlying hedged item is recognized in earnings.

At December 31, 2023 and 2022, a 10% change in market prices for our derivative instruments would not materially impact pre-tax income, the fair values of our derivative assets and liabilities, or OCI.

See additional commodity risk and derivative information in Note 9 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Interest Rate Risk

Periodically, we have engaged in activities to manage risks associated with changes in interest rates. We have utilized pay-fixed interest rate swap agreements to reduce exposure to interest rate fluctuations associated with floating rate debt obligations and anticipated debt refinancings. At December 31, 2023, we had no interest rate swaps in place. Further details of past swap agreements are set forth in Note 9 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

At December 31, 2023, over 99% of our debt is fixed rate debt, which limits our exposure to variable interest rate fluctuations. A hypothetical 100 basis point increase in the benchmark rate on our variable rate debt would have increased annual pretax interest expense by approximately $0.9 million and $4.1 million for the years ended December 31, 2023 and 2022, respectively. See Note 8 for further information on cash amounts outstanding under short- and long-term variable rate borrowings.

We are subject to interest rate risk associated with our pension and post-retirement benefit obligations. Changes in interest rates impact the liabilities associated with these benefit plans as well as the amount of income or expense recognized for these plans. Declines in the value of the plan assets could diminish the funded status of the pension plans and potentially increase the requirements to make cash contributions to these plans. See additional information in Note 13 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Credit Risk

We have adopted the Black Hills Corporation Credit Policy that establishes guidelines, controls and limits to manage and mitigate credit risk within risk tolerances established by the Board of Directors. We attempt to mitigate our credit exposure by conducting business primarily with high credit quality entities, setting tenor and credit limits commensurate with counterparty financial strength, obtaining master netting agreements and mitigating credit exposure with less creditworthy counterparties through parental guarantees, cash collateral requirements, letters of credit and other security agreements.

We perform periodic credit evaluations of our customers and adjust credit limits based upon payment history and the customer’s current creditworthiness, as determined by review of their current credit information. We maintain a provision for estimated credit losses based upon historical experience, changes in current market conditions, expected losses and any specific customer collection issue that is identified.

See more information in Notes 1 and 9 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

ITEM 8.FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management’s Report on Internal Control Over Financial Reporting

We are responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2023, based on the criteria set forth in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission “COSO”. This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Based on our evaluation, we have concluded that our internal control over financial reporting was effective as of December 31, 2023.

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of Black Hills Corporation’s financial statements, has issued an attestation report on the effectiveness of Black Hills Corporation's internal control over financial reporting as of December 31, 2023. Deloitte & Touche LLP's report on Black Hills Corporation's internal control over financial reporting is included herein.

Black Hills Corporation

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Black Hills Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Black Hills Corporation and subsidiaries (the "Company") as of December 31, 2023 and 2022, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2023, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2023, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 14, 2024, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Accounting — Impact of Rate Regulation on the Financial Statements — Refer to Notes 1 and 2 to the Financial Statements.

Critical Audit Matter Description

The Company is subject to cost-of-service regulation and earnings oversight by state and federal utility commissions (collectively, the “Commissions”), which have jurisdiction over the Company’s electric rates in Colorado, Montana, South Dakota and Wyoming and natural gas rates in Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming. Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as property, plant, and equipment; regulatory assets and liabilities; revenue; operating expenses; and income tax benefit (expense).

Rates are regulated on a state-by-state basis by the relevant state regulatory commissions based on an analysis of the Company's costs, as reviewed and approved in a regulatory proceeding. Rate regulation is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. Decisions to be made by the Commissions in the future will impact the accounting for regulated operations, including decisions about the amount of allowable costs and return on invested capital included in rates and any refunds that may be required. While the Company has indicated its regulatory assets are probable of recovery in current rates or in future proceedings, there is a risk that the Commissions will not judge all costs to have been prudently incurred or that the rate regulation process in which rates are determined will not always result in rates that produce a full recovery of costs and the return on invested capital.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, and (2) a refund or future rate reduction to be provided to customers. Given the uncertainty of future decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following, among others:

- We tested the effectiveness of management’s controls over the evaluation of the likelihood of (1) the recovery in future rates of costs incurred as property, plant, and equipment and deferred as regulatory assets, and (2) refunds or future reductions in rates that should be reported as regulatory liabilities. We tested the effectiveness of management’s controls over the initial recognition of amounts as property, plant, and equipment; regulatory assets or liabilities; and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- We read relevant regulatory orders issued by the Commissions, filings made by the Company, and other publicly available information, as appropriate, to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions’ treatment of similar costs under similar circumstances. We evaluated the external information and compared it to the Company’s recorded regulatory asset and liability balances for completeness and for any evidence that might contradict management’s assertions.
- We obtained and evaluated an analysis from management regarding probability of recovery for regulatory assets or refund or future reduction in rates for regulatory liabilities not yet addressed in a regulatory order, as applicable, to assess management’s assertion that amounts are probable of recovery or of a future reduction in rates.
- We inspected minutes of the board of directors to identify any evidence that may contradict management’s assertions regarding probability of recovery or refunds. We also inquired of management regarding current year rate filings and new regulatory assets or liabilities.
- We evaluated the Company’s disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 14, 2024

We have served as the Company's auditor since 2002.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Black Hills Corporation

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Black Hills Corporation and subsidiaries (the “Company”) as of December 31, 2023, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2023, of the Company and our report dated February 14, 2024, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 14, 2024

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

	December 31, 2023	December 31, 2022	December 31, 2021
	(in millions, except per share amounts)		
Revenue	$ 2,331.3	$ 2,551.8	$ 1,949.1
Operating expenses:			
Fuel, purchased power and cost of natural gas sold	982.9	1,230.6	741.9
Operations and maintenance	552.0	548.4	501.7
Depreciation and amortization	256.8	250.9	236.0
Taxes - property and production	66.9	66.7	60.1
Total operating expenses	1,858.6	2,096.6	1,539.7
Operating income	472.7	455.2	409.4
Other income (expense):			
Interest expense incurred net of amounts capitalized	(180.0)	(162.6)	(154.1)
Interest income	12.1	1.6	1.7
Other income (expense), net	(3.2)	1.8	1.4
Total other income (expense)	(171.1)	(159.2)	(151.0)
Income before income taxes	301.6	296.0	258.4
Income tax (expense)	(25.6)	(25.2)	(7.2)
Net income	276.0	270.8	251.2
Net income attributable to non-controlling interest	(13.8)	(12.4)	(14.5)
Net income available for common stock	262.2	$ 258.4	$ 236.7
Earnings per share of common stock:			
Earnings per share, Basic	3.91	$ 3.98	$ 3.74
Earnings per share, Diluted	3.91	$ 3.97	$ 3.74
Weighted average common shares outstanding:			
Basic	67.0	64.9	63.2
Diluted	67.1	65.0	63.3

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended	December 31, 2023	December 31, 2022	December 31, 2021
		(in millions)	
Net income	$ 276.0	$ 270.8	$ 251.2
Other comprehensive income (loss), net of tax:			
Benefit plan liability adjustments - net gain (loss) (net of tax of $0, $(1.5), and $(0.7), respectively)	(0.3)	4.6	2.0
Reclassification adjustment of benefit plan liability - net loss (net of tax of $0, $(0.2), and $(0.7), respectively)	0.2	0.5	1.7
Reclassification adjustment of benefit plan liability - prior service cost (net of tax of $0, $0, and $0, respectively)	—	(0.1)	(0.1)
Derivative instruments designated as cash flow hedges:			
Reclassification of net realized (gains) losses on settled/amortized interest rate swaps (net of tax of $(0.7), $(0.7), and $(0.7), respectively)	2.2	2.1	2.2
Net unrealized gains (losses) on commodity derivatives (net of tax of $1.1, $0.2, and $(1.0), respectively)	(3.6)	(0.6)	3.0
Reclassification of net realized (gains) losses on settled commodity derivatives (net of tax of $(0.7), $0.7, and $0.5, respectively)	2.3	(2.0)	(1.5)
Other comprehensive income (loss), net of tax	0.8	4.5	7.3
Comprehensive income	276.8	275.3	258.5
Less: comprehensive income attributable to non-controlling interest	(13.8)	(12.4)	(14.5)
Comprehensive income available for common stock	$ 263.0	$ 262.9	$ 244.0

See Note 11 for additional disclosures related to Comprehensive Income.

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

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BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS

	As of December 31, 2023	As of December 31, 2022
	(in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 86.6	$ 21.4
Restricted cash and equivalents	6.4	5.6
Accounts receivable, net	350.3	508.2
Materials, supplies and fuel	160.9	207.4
Derivative assets, current	—	0.6
Income tax receivable, net	18.5	17.6
Regulatory assets, current	175.7	260.3
Other current assets	28.2	50.6
Total current assets	826.6	1,071.7
Property, plant and equipment	8,917.2	8,374.8
Less accumulated depreciation and depletion	(1,797.9)	(1,576.8)
Total property, plant and equipment, net	7,119.3	6,798.0
Other assets:		
Goodwill	1,299.5	1,299.5
Intangible assets, net	8.4	9.6
Regulatory assets, non-current	304.4	392.7
Other assets, non-current	62.2	46.7
Total other assets, non-current	1,674.5	1,748.5
TOTAL ASSETS	$ 9,620.4	$ 9,618.2

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS
(Continued)

	As of	
	December 31, 2023	December 31, 2022
	(in millions, except share amounts)	
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 186.4	$ 310.0
Accrued liabilities	293.3	243.5
Derivative liabilities, current	6.5	6.6
Regulatory liabilities, current	98.9	46.0
Notes payable	—	535.6
Current maturities of long-term debt	600.0	525.0
Total current liabilities	1,185.1	1,666.7
Long-term debt, net of current maturities	3,801.2	3,607.3
Deferred credits and other liabilities:		
Deferred income tax liabilities, net	548.0	508.9
Regulatory liabilities, non-current	467.7	472.6
Benefit plan liabilities	123.9	116.7
Other deferred credits and other liabilities	188.7	156.1
Total deferred credits and other liabilities	1,328.3	1,254.3
Commitments, contingencies and guarantees (Note 3)		
Equity:		
Stockholders' equity -		
Common stock $1.00 par value; 100,000,000 shares authorized; issued: 68,265,042 and 66,140,396, respectively	68.3	66.1
Additional paid-in capital	2,007.7	1,882.7
Retained earnings	1,158.2	1,064.1
Treasury stock at cost - 68,073 and 36,726, respectively	(4.1)	(2.4)
Accumulated other comprehensive income (loss)	(14.8)	(15.6)
Total stockholders' equity	3,215.3	2,994.9
Non-controlling interest	90.5	95.0
Total equity	3,305.8	3,089.9
TOTAL LIABILITIES AND TOTAL EQUITY	$ 9,620.4	$ 9,618.2

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended	December 31, 2023	December 31, 2022	December 31, 2021
		(in millions)	
Operating activities:			
Net income	$ 276.0	$ 270.8	$ 251.2
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	256.8	250.9	236.0
Deferred financing cost amortization	10.1	9.8	7.0
Stock compensation	7.0	8.6	9.7
Deferred income taxes	25.4	25.6	7.3
Employee benefit plans	11.5	5.5	9.6
Other adjustments, net	2.7	(4.7)	7.0
Change in certain operating assets and liabilities:			
Materials, supplies and fuel	51.4	(75.4)	(35.7)
Accounts receivable and other current assets	204.5	(184.5)	(43.2)
Accounts payable and other current liabilities	(109.9)	89.4	10.6
Regulatory assets	236.8	203.9	(514.7)
Regulatory liabilities	—	—	(9.5)
Other operating activities, net	(27.9)	(15.1)	0.1
Net cash provided by (used in) operating activities	944.4	584.8	(64.6)
Investing activities:			
Property, plant and equipment additions	(555.6)	(604.4)	(677.5)
Other investing activities	18.9	0.5	13.3
Net cash (used in) investing activities	(536.7)	(603.9)	(664.2)
Financing activities:			
Dividends paid on common stock	(168.1)	(156.7)	(145.0)
Common stock issued	118.3	90.1	119.0
Term Loan - borrowings	—	—	800.0
Term Loan - repayments	—	—	(800.0)
Net borrowings (payments) of Revolving Credit Facility and CP Program	(535.6)	115.4	186.1
Long-term debt - issuance	800.0	—	600.0
Long-term debt - repayments	(525.0)	—	(8.4)
Distributions to non-controlling interests	(18.3)	(17.4)	(15.7)
Other financing activities	(13.0)	0.9	(4.1)
Net cash provided by (used in) financing activities	(341.7)	32.3	731.9
Net change in cash, restricted cash and cash equivalents	66.0	13.2	3.1
Cash, restricted cash and cash equivalents beginning of year	27.0	13.8	10.7
Cash, restricted cash and cash equivalents end of year	$ 93.0	$ 27.0	$ 13.8
Supplemental cash flow information:			
Cash (paid) refunded during the period:			
Interest (net of amounts capitalized)	$ (157.3)	$ (152.5)	$ (142.7)
Income taxes	$ (1.0)	$ 0.8	$ 1.5
Non-cash investing and financing activities:			
Accrued property, plant and equipment purchases at December 31	$ 52.4	$ 59.3	$ 68.8
Increase in capitalized assets associated with asset retirement obligations	$ 3.8	$ 14.0	$ 2.1

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY

	Common Stock		Treasury Stock						
(in millions except share amounts)	Shares	Value	Shares	Value	Additional Paid in Capital	Retained Earnings	AOCI	Non controlling Interest	Total
Balance at December 31, 2020	62,827,179	$ 62.8	32,492	$ (2.1)	$ 1,657.3	$ 870.7	$ (27.4)	$ 101.2	$ 2,662.5
Net income	—	—	—	—	—	236.7	—	14.5	251.2
Other comprehensive income, net of tax	—	—	—	—	—	—	7.3	—	7.3
Dividends on common stock ($2.29 per share)	—	—	—	—	—	(145.0)	—	—	(145.0)
Share-based compensation	153,719	0.2	21,586	(1.4)	9.2	—	—	—	8.0
Issuance of common stock	1,812,197	1.8	—	—	118.1	—	—	—	119.9
Issuance costs	—	—	—	—	(1.2)	—	—	—	(1.2)
Distributions to non-controlling interest	—	—	—	—	—	—	—	(15.7)	(15.7)
Balance at December 31, 2021	64,793,095	$ 64.8	54,078	$ (3.5)	$ 1,783.4	$ 962.4	$ (20.1)	$ 100.0	$ 2,887.0
Net income	—	—	—	—	—	258.4	—	12.4	270.8
Other comprehensive income, net of tax	—	—	—	—	—	—	4.5	—	4.5
Dividends on common stock ($2.41 per share)	—	—	—	—	—	(156.7)	—	—	(156.7)
Share-based compensation	39,546	—	(17,352)	1.1	10.5	—	—	—	11.6
Issuance of common stock	1,307,755	1.3	—	—	89.9	—	—	—	91.2
Issuance costs	—	—	—	—	(1.1)	—	—	—	(1.1)
Distributions to non-controlling interest	—	—	—	—	—	—	—	(17.4)	(17.4)
Balance at December 31, 2022	66,140,396	$ 66.1	36,726	$ (2.4)	$ 1,882.7	$ 1,064.1	$ (15.6)	$ 95.0	$ 3,089.9
Net income	—	—	—	—	—	262.2	—	13.8	276.0
Other comprehensive income, net of tax	—	—	—	—	—	—	0.8	—	0.8
Dividends on common stock ($2.50 per share)	—	—	—	—	—	(168.1)	—	—	(168.1)
Share-based compensation	93,257	0.1	31,347	(1.7)	8.8	—	—	—	7.2
Issuance of common stock	2,031,389	2.1	—	—	117.9	—	—	—	120.0
Issuance costs	—	—	—	—	(1.7)	—	—	—	(1.7)
Distributions to non-controlling interest	—	—	—	—	—	—	—	(18.3)	(18.3)
Balance at December 31, 2023	68,265,042	$ 68.3	68,073	$ (4.1)	$ 2,007.7	$ 1,158.2	$ (14.8)	$ 90.5	$ 3,305.8

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
Notes to Consolidated Financial Statements
December 31, 2023, 2022 and 2021

(1) BUSINESS DESCRIPTION AND SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Corporation is a customer-focused, growth-oriented utility company headquartered in Rapid City, South Dakota. We are a holding company that, through our subsidiaries, conducts our operations through the following reportable segments: Electric Utilities and Gas Utilities. Certain unallocated corporate expenses that support our operating segments are presented as Corporate and Other.

Use of Estimates and Basis of Presentation

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Changes in facts and circumstances or additional information may result in revised estimates and actual results could differ materially from those estimates.

Principles of Consolidation

The consolidated financial statements include the accounts of Black Hills Corporation and its wholly-owned and majority-owned and controlled subsidiaries. Furthermore, VIEs in which the Company has an ownership interest and is the primary beneficiary, thus controlling the VIE, have been consolidated. All intercompany balances and transactions have been eliminated in consolidation.

We use the proportionate consolidation method to account for our ownership interest in any jointly-owned facility. See Note 6 for additional information.

Non-controlling Interests

We account for changes in our controlling interests of subsidiaries according to ASC 810*, Consolidation.* ASC 810 requires that the Company record such changes as equity transactions, recording no gain or loss on such a sale. GAAP requires that non-controlling interests in subsidiaries and affiliates be reported in the equity section of a company's balance sheet. In addition, the amounts attributable to the non-controlling interest net income (loss) of those subsidiaries are reported separately in the consolidated statements of income and comprehensive income. See Note 12 for additional information.

Variable Interest Entities

We evaluate arrangements and contracts with other entities to determine if they are VIEs and if we are the primary beneficiary. GAAP provides a framework for identifying VIEs and determining when a company should include the assets, liabilities, non-controlling interest and results of activities of a VIE in its consolidated financial statements.

A VIE should be consolidated if a party with an ownership, contractual or other financial interest in the VIE (a variable interest holder) has the power to direct the VIE's most significant activities and the obligation to absorb losses or right to receive benefits of the VIE that could be significant to the VIE. A variable interest holder that consolidates the VIE is called the primary beneficiary. Upon consolidation, the primary beneficiary generally must initially record all of the VIE's assets, liabilities and non-controlling interests at fair value and subsequently account for the VIE as if it were consolidated.

Our evaluation of whether our interest qualifies as the primary beneficiary of a VIE involves significant judgments, estimates and assumptions and includes a qualitative analysis of the activities that most significantly impact the VIE's economic performance and whether the Company has the power to direct those activities, the design of the entity, the rights of the parties and the purpose of the arrangement. Black Hills Colorado IPP is a VIE. See Note 12 for additional information.

Cash, Cash Equivalents and Restricted Cash

We consider all highly liquid investments with an original maturity of three months or less to be cash and cash equivalents. We maintain cash accounts for various specified purposes, which are classified as restricted cash.

Revenue Recognition

Our revenue contracts generally provide for performance obligations that are fulfilled and transfer control to customers over time, represent a series of distinct services that are substantially the same, involve the same pattern of transfer to the customer and provide a right to consideration from our customers in an amount that corresponds directly with the value to the customer for the performance completed to date. Therefore, we recognize revenue in the amount to which we have a right to invoice. Our primary types of revenue contracts are:

- Regulated natural gas and electric utility services tariffs - Our Utilities have regulated operations, as defined by ASC 980, *Regulated Operations,* that provide services to regulated customers under tariff rates, charges, terms and conditions of service and prices determined by the jurisdictional regulators designated for our service territories. Our regulated services primarily encompass single performance obligations for delivery of either commodity natural gas, commodity electricity, natural gas transportation or electric transmission services. These service revenues are variable based on quantities delivered, influenced by seasonal business and weather patterns. Tariffs are only permitted to be changed through a rate-setting process involving the state or federal regulatory commissions to establish contractual rates between the utility and its customers. All of our Utilities' regulated sales are subject to regulatory-approved tariffs.

- Power sales agreements - Our Electric Utilities segment has long-term wholesale power sales agreements with other load-serving entities, including affiliates, for the sale of excess power from owned generating units. These agreements include a combination of "take or pay" arrangements, where the customer is obligated to pay for the energy regardless of whether it actually takes delivery, as well as "requirements only" arrangements, where the customer is only obligated to pay for the energy the customer needs. In addition to these long-term contracts, we also sell excess energy to other load-serving entities on a short-term basis. The pricing for all of these arrangements is included in the executed contracts or confirmations, reflecting the standalone selling price and is variable based on energy delivered. Certain energy sale and purchase transactions with the same counterparty and at the same delivery point are netted to reflect the economic substance of the arrangement.

The majority of our revenue contracts are based on variable quantities delivered. Any fixed consideration contracts with an expected duration of one year or more are immaterial to our consolidated revenues. Variable consideration constraints in the form of discounts, rebates, credits, price concessions, incentives, performance bonuses, penalties or other similar items are not material for our revenue contracts. We are the principal in our revenue contracts, as we have control over the services prior to those services being transferred to the customer.

Revenue Not in Scope of ASC 606

Other revenues included in the tables in Note 4 include our revenue accounted for under separate accounting guidance, including lease revenue under ASC 842, *Leases,* derivative revenue under ASC 815, *Derivatives and Hedging,* and alternative revenue programs revenue under ASC 980, *Regulated Operations*.

Significant Judgments and Estimates

Unbilled Revenue

To the extent that deliveries have occurred, but a bill has not been issued, our Utilities accrue an estimate of the revenue since the latest billing. This estimate is calculated based upon several factors including billings through the last billing cycle in a month and prices in effect in our jurisdictions. Each month, the estimated unbilled revenue amounts are trued-up and recorded in Accounts receivable, net on the accompanying Consolidated Balance Sheets.

Contract Balances

The nature of our primary revenue contracts provides an unconditional right to consideration upon service delivery; therefore, no customer contract assets or liabilities exist. The unconditional right to consideration is represented by the balance in our Accounts receivable, which is further discussed below.

See Note 4 for additional information.

Accounts Receivable and Allowance for Credit Losses

Accounts receivable are stated at billed and estimated unbilled amounts, net of allowance for credit losses, and do not bear interest. We maintain an allowance for credit losses which reflects our estimate of uncollectible trade receivables. We regularly review our trade receivable allowance by considering such factors as historical experience, credit worthiness, the age of the receivable balances and current economic conditions that may affect collectability.

In specific cases where we are aware of a customer's inability or reluctance to pay, we record an allowance for credit losses to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be affected. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, expected losses, the level of commodity prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible or the time allowed for dispute under the contract has expired.

We utilize master netting agreements which consist of an agreement between two parties who have multiple contracts with each other that provide for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties.

Following is a summary of accounts receivable as of December 31 (in millions):

	2023	2022
Billed Accounts Receivable	$ 198.5	$ 267.6
Unbilled Revenue	154.0	243.6
Less Allowance for Credit Losses	(2.2)	(3.0)
Accounts Receivable, net	$ 350.3	$ 508.2

Changes to allowance for credit losses for the years ended December 31, were as follows (in millions):

	Balance at Beginning of Year	Additions Charged to Costs and Expenses	Recoveries and Other Additions	Write-offs and Other Deductions	Balance at End of Year
2023	$ 3.0	$ 8.7	$ 4.1	$ (13.6)	$ 2.2
2022	$ 2.1	$ 9.1	$ 3.5	$ (11.7)	$ 3.0
2021	$ 7.0	$ 2.4	$ 3.6	$ (10.9)	$ 2.1

Materials, Supplies and Fuel

Materials and supplies represent parts and supplies for our business operations. Fuel represents diesel oil and gas used by our electric generating facilities to produce power. Natural gas in storage primarily represents gas purchased for use by our gas customers. All of our Materials, supplies and fuel are recorded using the weighted-average cost method and are valued at the lower-of-cost or net realizable value. The value of our natural gas in storage fluctuates with seasonal volume requirements of our business and the commodity price of natural gas.

The following amounts by major classification are included in Materials, supplies and fuel on the accompanying Consolidated Balance Sheets as of December 31 (in millions):

	2023	2022
Materials and supplies	$ 105.9	$ 99.7
Fuel	7.7	3.1
Natural gas in storage	47.3	104.6
Total materials, supplies and fuel	$ 160.9	$ 207.4

Property, Plant and Equipment

Property, plant and equipment are stated at cost, which includes construction-related direct labor and material costs, indirect construction costs including labor and related costs of departments associated with supporting construction activities, and AFUDC. Additions to and significant replacements of property are charged to property, plant and equipment at cost. We also classify our Cushion Gas as Property, plant and equipment. Ordinary repairs and maintenance of property, except as allowed under rate regulations, are charged to operations as incurred.

We receive contributions in aid of construction (CIACs) from third parties that are generally intended to defray all or a portion of the costs for certain capital projects. Such CIAC costs are recorded as a reduction to Property, plant, and equipment.

The cost of regulated utility property, plant and equipment retired, or otherwise disposed in the ordinary course of business, less salvage plus retirement costs, is charged to accumulated depreciation. Estimated removal costs related to our regulated properties that do not have legal retirement obligations are reclassified from accumulated depreciation and reflected as regulatory liabilities. Retirement or disposal of all other operating assets result in gains or losses recognized as a reduction to Operations and maintenance expense.

See Note 5 for additional information.

Depreciation

Depreciation provisions for property, plant and equipment are generally computed on a straight-line basis based on the applicable estimated service life of the various classes of property. The composite depreciation method is applied to regulated utility property. Depreciation studies are conducted periodically to update composite rates and are approved by state utility commissions and/or the FERC when required. Capitalized mining costs and coal leases are amortized on a unit-of-production method based on volumes produced and estimated reserves. For certain non-regulated power plant components, depreciation is computed on a unit-of-production methodology based on plant hours run.

AFUDC

Included in the cost of regulated construction projects is AFUDC, when applicable, which represents the approximate composite cost of borrowed funds and a return on equity used to finance a regulated utility project. The following table presents AFUDC amounts (in millions) for the years ended December 31:

	Income Statement Location	2023	2022	2021
AFUDC Borrowed	Interest expense incurred, net of amounts capitalized	$ 6.0	$ 5.6	$ 4.1
AFUDC Equity	Other income (expense), net	0.4	0.6	0.6

We also capitalize interest, when applicable, on undeveloped leasehold costs and certain non-regulated construction projects. In addition, asset retirement costs associated with tangible long-lived regulated utility assets are recognized as liabilities with an increase to the carrying amounts of the related long-lived regulated utility assets in the period incurred. The amounts capitalized are included in Property, plant and equipment on the accompanying Consolidated Balance Sheets.

Asset Retirement Obligations

Accounting standards for AROs associated with long-lived assets require that the present value of retirement costs for which we have a legal obligation be recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The associated ARO accretion expense for our non-regulated operations, and regulated operations without a corresponding recovery mechanism, is included within Depreciation, depletion and amortization on the accompanying Consolidated Statements of Income. The accounting for the obligation for regulated operations with a regulatory mechanism has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset or a regulatory liability.

We initially record liabilities for the present value of retirement costs for which we have a legal obligation, with an equivalent amount added to the asset cost. The asset is then depreciated or depleted over the appropriate useful life and the liability is accreted over time by applying an interest method of allocation. Any difference in the actual cost of the settlement of the liability and the recorded amount is recognized as a gain or loss in the results of operations at the time of settlement for our non-regulated operations. See Note 7 for additional information.

Goodwill and Intangible Assets

Goodwill and intangible assets with indefinite lives are not amortized, but the carrying values are reviewed upon an indicator of impairment or at least annually. Intangible assets with a finite life are amortized over their estimated useful lives.

We perform a goodwill impairment test on an annual basis or upon the occurrence of events or changes in circumstances that indicate that the asset might be impaired. Our annual goodwill impairment testing date is as of October 1, which aligns our testing date with our financial planning process.

The Company has determined that the reporting units for its goodwill impairment test are its operating segments, or components of an operating segment.

Our goodwill impairment analysis includes an income approach and a market approach to estimate the fair value of our reporting units. These valuations require significant judgments, including, but not limited to: 1) estimates of future cash flows, based on our internal five-year business plans and adjusted as appropriate for our view of market participant assumptions, with long range cash flows estimated using a terminal value calculation; 2) estimates of long-term growth rates for our businesses; 3) the determination of an appropriate weighted-average cost of capital or discount rate; and 4) the utilization of market information such as recent sales transactions for comparable assets within the utility and energy industries.

We believe that goodwill reflects the inherent value of the relatively stable, long-lived cash flows of our Utilities businesses, considering the regulatory environment, and the long-lived cash flow and rate base growth opportunities at our Utilities, and those businesses vertically integrated. Goodwill amounts have not changed since 2016.

As of December 31, 2023 and 2022, Goodwill balances were as follows (in millions):

	Electric Utilities	Gas Utilities	Total
Goodwill	$ 257.3	$ 1,042.2	$ 1,299.5

Our intangible assets represent contract intangibles, easements, rights-of-way, customer listings and trademarks. The finite-lived intangible assets are amortized using a straight-line method based on estimated useful lives; these assets are currently being amortized from 2 years to 41 years. Changes to intangible assets for the years ended December 31, were as follows (in millions):

	2023	2022	2021
Intangible assets, net, beginning balance	$ 9.6	$ 10.8	$ 11.9
Amortization expense [(a)]	(1.2)	(1.2)	(1.1)
Intangible assets, net, ending balance	$ 8.4	$ 9.6	$ 10.8

(a) Amortization expense for existing intangible assets is expected to be $1.2 million for each year of the next five years.

Accrued Liabilities

The following amounts by major classification are included in Accrued liabilities on the accompanying Consolidated Balance Sheets as of December 31 (in millions):

	2023	2022
Accrued employee compensation, benefits and withholdings	$ 74.8	$ 62.9
Accrued property taxes	52.7	52.4
Customer deposits and prepayments	76.0	47.7
Accrued interest	46.3	33.8
Other (none of which is individually significant)	43.5	46.7
Total accrued liabilities	$ 293.3	$ 243.5

Fair Value Measurements

Financial Instruments

We use the following fair value hierarchy for determining inputs for our financial instruments. Our assets and liabilities for financial instruments are classified and disclosed in one of the following fair value categories:

Level 1 — Unadjusted quoted prices available in active markets that are accessible at the measurement date for identical unrestricted assets or liabilities. Level 1 instruments primarily consist of highly liquid and actively traded financial instruments with quoted pricing information on an ongoing basis.

Level 2 — Pricing inputs include quoted prices for identical or similar assets and liabilities in active markets other than quoted prices in Level 1, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 — Pricing inputs are generally less observable from objective sources. These inputs reflect management’s best estimate of fair value using its own assumptions about the assumptions a market participant would use in pricing the asset or liability.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels. We record transfers, if necessary, between levels at the end of the reporting period for all of our financial instruments.

Transfers into Level 3, if any, occur when significant inputs used to value the derivative instruments become less observable, such as a significant decrease in the frequency and volume in which the instrument is traded, negatively impacting the availability of observable pricing inputs. Transfers out of Level 3, if any, occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery date of a transaction becomes shorter, positively impacting the availability of observable pricing inputs.

Valuation Methodologies for Derivatives

The wholesale electric energy and natural gas commodity contracts for our Utilities are valued using the market approach and include forward strip pricing at liquid delivery points, exchange-traded futures, options, basis swaps and over-the-counter swaps and options (Level 2). For exchange-traded futures, options and basis swap assets and liabilities, fair value was derived using broker quotes validated by the exchange settlement pricing for the applicable contract. For over-the-counter instruments, the fair value is obtained by utilizing a nationally recognized service that obtains observable inputs to compute the fair value, which we validate by comparing our valuation with the counterparty. The fair value of these swaps includes a credit valuation adjustment based on the credit spreads of the counterparties when we are in an unrealized gain position or on our own credit spread when we are in an unrealized loss position.

See Notes 10 and 13 for additional information.

Derivatives and Hedging Activities

All our derivatives are measured at fair value and recognized as either assets or liabilities on the Consolidated Balance Sheets, except for derivative contracts that qualify for and are elected under the normal purchase and normal sales exception. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable amount of time and pricing is clearly and closely related to the asset being purchased or sold. Normal purchase and sales contracts are recognized when the underlying physical transaction is completed under the accrual basis of accounting.

In addition, certain derivative contracts approved by regulatory authorities are either recovered or refunded through customer rates. Any changes in the fair value of these approved derivative contracts are deferred as a regulatory asset or regulatory liability pursuant to ASC 980, *Regulated Operations*.

We also have some derivatives that qualify for hedge accounting and are designated as cash flow hedges. The gain or loss on these designated derivatives is deferred in AOCI and reclassified into earnings when the corresponding hedged transaction is recognized in earnings. Changes in the fair value of all other derivative contracts are recognized in earnings.

We utilize master netting agreements which consist of an agreement between two parties who have multiple contracts with each other that provide for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. Accounting standards also permit offsetting of fair value amounts recognized for the right to reclaim, or the obligation to return, cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty. We reflect the offsetting of net derivative positions with fair value amounts for cash collateral with the same counterparty when a legal right of offset exists. Therefore, the gross amounts are not indicative of either our actual credit or net economic exposures.

The cash impacts of settled derivatives are recorded as operating activities on the Consolidated Statements of Cash Flows.

See Notes 9, 10 and 11 for additional information.

Debt Discounts, Premiums and Deferred Financing Costs

Deferred financing costs include loan origination fees, underwriter fees, legal fees and other costs directly attributable to the issuance of debt. Debt discounts, premiums and deferred financing costs are amortized over the estimated useful life of the related debt. Unamortized discounts, premiums and deferred financing costs are presented on the balance sheet as an adjustment to the related debt liabilities. See Note 8 for additional information.

Regulatory Accounting

Our regulated Utilities are subject to cost-of-service regulation and earnings oversight from federal and state regulatory commissions. Our Utilities account for income and expense items in accordance with accounting standards for regulated operations. These accounting policies differ in some respects from those used by our non-regulated businesses. Under these regulated operations accounting standards:

- Certain costs, which would otherwise be charged to expense or OCI, are deferred as regulatory assets based on the expected ability to recover the costs in future rates.
- Certain credits, which would otherwise be reflected as income or OCI, are deferred as regulatory liabilities based on the expectation the amounts will be returned to customers in future rates, or because the amounts were collected in rates prior to the costs being incurred.

Management continually assesses the probability of future recoveries and obligations associated with regulatory assets and liabilities. Factors such as the current regulatory environment, recently issued rate orders, and historical precedents are considered. As a result, we believe that the accounting prescribed under rate-based regulation remains appropriate and our regulatory assets are probable of recovery in current rates or in future rate proceedings.

If changes in the regulatory environment occur, we may no longer be eligible to apply this accounting treatment and may be required to eliminate regulatory assets and liabilities from our balance sheet. Such changes could adversely affect our results of operations, financial position or cash flows.

See Note 2 for additional information.

Income Taxes

The Company is subject to federal income tax as well as income tax in various state and local jurisdictions. The Company and its subsidiaries file consolidated federal income tax returns. Each subsidiary records both federal and state income taxes as if it were a separate taxpayer and consolidating expense adjustments are allocated to the subsidiaries based on separate company computations of taxable income or loss.

We use the asset and liability method in accounting for income taxes. Under the asset and liability method, deferred income taxes are recognized at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities as well as operating loss and tax credit carryforwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements.

It is our policy to apply the flow-through method of accounting for ITCs. Under the flow-through method, ITCs are reflected in net income as a reduction to income tax expense in the year they qualify. An exception to this general policy is the deferral method, which applies to our regulated businesses. Such a method results in the ITC being amortized as a reduction to income tax expense over the estimated useful lives of the underlying property that gave rise to the credit.

We recognize interest income or interest expense and penalties related to income tax matters in Income tax expense on the Consolidated Statements of Income.

We have elected to account for transferable clean energy tax credits, including PTCs and ITCs within the provision for income taxes.

We account for uncertainty in income taxes recognized in the financial statements in accordance with the accounting standards for income taxes. The unrecognized tax benefit is classified in Other deferred credits and other liabilities or in Deferred income tax liabilities, net on the accompanying Consolidated Balance Sheets. See Note 15 for additional information.

Earnings per Share of Common Stock

Basic earnings per share is computed by dividing Net income available for common stock by the weighted average number of common shares outstanding during each year. Diluted earnings per share is computed by including all dilutive common shares outstanding during each year. Diluted common shares are primarily due to equity units, outstanding stock options, restricted stock and performance shares under our equity compensation plans.

A reconciliation of share amounts used to compute earnings per share is as follows for the years ended December 31 (in millions, except earnings per share amounts):

	2023	2022	2021
Net income available for common stock	$ 262.2	$ 258.4	$ 236.7
Weighted average shares - basic	67.0	64.9	63.2
Dilutive effect of equity compensation	0.1	0.1	0.1
Weighted average shares - diluted	67.1	65.0	63.3
Net income available for common stock, per share - Diluted	$ 3.91	$ 3.97	$ 3.74

The following securities were excluded from the diluted earnings per share computation for the years ended December 31 because of their anti-dilutive nature:

	2023	2022	2021
Equity compensation	46,275	—	13,101
Anti-dilutive shares excluded from computation of earnings per share	46,275	—	13,101

Share-Based Compensation

We account for our share-based compensation arrangements in accordance with ASC 718, *Compensation-Stock Compensation*, by recognizing compensation costs for all share-based awards over the respective service period for employee services received in exchange for an award of equity or equity-based compensation. Awards that will be settled in stock are accounted for as equity and the compensation expense is based on the grant date fair value. Awards that are settled in cash are accounted for as liabilities and the compensation expense is re-measured each period based on the current market price and performance achievement measures. See Note 14 for additional information.

Pension and Other Postretirement Plans

We recognize on our Consolidated Balance Sheets an asset or liability reflecting the funded status of pension and other postretirement plans with current-year changes in actuarial gains or losses recognized in AOCI, except for those plans at certain of our regulated utilities that can recover portions of their pension and postretirement obligations through future rates. All plan assets are recorded at fair value. We follow the measurement date provisions of ASC 715, *Compensation-Retirement Benefit*s, which require a year-end measurement date of plan assets and obligations for all defined benefit plans.

Recently Issued Accounting Standards

Improvements to Reportable Segment Disclosures, ASU 2023-07

In November 2023, the FASB issued ASU 2023-07, *Improvements to Reportable Segment Disclosures,* which expands public entities' segment disclosures by requiring disclosure of significant segment expenses that are regularly reviewed by the CODM and included within each reported measure of segment profit or loss, an amount and description of its composition for other segment items, and interim disclosures of a reportable segment's profit or loss and assets. The ASU also allows, in addition to the measure that is most consistent with GAAP, the disclosure of additional measures of segment profit or loss that are used by the CODM in assessing segment performance and deciding how to allocate resources. The ASU is effective for our Annual Report on Form 10-K for the fiscal year ended December 31, 2024, and subsequent interim periods, with early adoption permitted. We do not expect the ASU to have an impact on our financial position, results of operations and cash flows; however, are currently evaluating the impact on our consolidated financial statement disclosures.

Improvements to Income Tax Disclosures, ASU 2023-09

In December 2023, the FASB issued ASU 2023-09, *Improvements to Income Tax Disclosures,* which expands public entities' annual disclosures by requiring disclosure of tax rate reconciliation amounts and percentages for specific categories, income taxes paid disaggregated by federal and state taxes, and income tax expense disaggregated by federal and state taxes jurisdiction. The ASU is effective for our Annual Report on Form 10-K for the fiscal year ended December 31, 2025, with early adoption permitted. We do not expect the ASU to have an impact on our financial position, results of operations and cash flows; however, are currently evaluating the impact on our consolidated financial statement disclosures.

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(2) REGULATORY MATTERS

We had the following regulatory assets and liabilities as of December 31 (in millions):

	2023	2022
Regulatory assets		
Winter Storm Uri [(a)]	$ 199.6	$ 348.0
Deferred energy and fuel cost adjustments [(b)]	55.1	72.6
Deferred gas cost adjustments [(b)]	4.1	12.2
Gas price derivatives [(b)]	5.1	8.8
Deferred taxes on AFUDC [(b)]	7.1	7.3
Employee benefit plans and related deferred taxes [(c)]	89.3	89.3
Environmental [(b)]	2.9	1.3
Loss on reacquired debt [(b)]	17.4	19.2
Deferred taxes on flow-through accounting [(b)]	74.7	69.5
Decommissioning costs [(b)]	2.4	3.5
Other regulatory assets [(b)]	22.4	21.3
Total regulatory assets	480.1	653.0
Less current regulatory assets	(175.7)	(260.3)
Regulatory assets, non-current	$ 304.4	$ 392.7
Regulatory liabilities		
Deferred energy and gas costs [(b)]	$ 88.9	$ 41.7
Employee benefit plans and related deferred taxes [(c)]	36.2	38.9
Cost of removal [(b)]	181.9	175.6
Excess deferred income taxes [(c)]	247.1	254.8
Other regulatory liabilities [(c)]	12.5	7.6
Total regulatory liabilities	566.6	518.6
Less current regulatory liabilities	(98.9)	(46.0)
Regulatory liabilities, non-current	$ 467.7	$ 472.6

(a) Timing of Winter Storm Uri incremental cost recovery and associated carrying costs vary by jurisdiction. See further information below.
(b) Recovery/repayment of costs, but we are not allowed a rate of return.
(c) In addition to recovery or repayment of costs, we are allowed a return on a portion of this amount or a reduction in rate base.

Regulatory assets represent items we expect to recover from customers through probable future rates.

Winter Storm Uri - Our Utilities have received commission approval to recover incremental fuel, purchased power and natural gas costs associated with Winter Storm Uri. In certain jurisdictions, we also received commission approval to recover carrying costs. As of December 31, 2023, we estimate that our remaining Winter Storm Uri regulatory asset has a weighted-average recovery period of 2.2 years.

Deferred Energy and Fuel Cost Adjustments - Deferred energy and fuel cost adjustments represent the cost of electricity delivered to our Electric Utilities' customers that is either higher or lower than the current rates and will be recovered or refunded in future rates. Deferred energy and fuel cost adjustments are recorded and recovered or amortized as approved by the appropriate state regulatory commission. Our Electric Utilities file periodic quarterly, semi-annual and/or annual filings to recover these costs based on the respective cost mechanisms approved by their applicable state regulatory commissions.

Deferred Gas Cost Adjustments - Our regulated Gas Utilities have GCA provisions that allow them to pass the cost of gas on to their customers. The GCA is based on forecasts of the upcoming gas costs and recovery or refund of prior under-recovered or over-recovered costs. To the extent that gas costs are under-recovered or over-recovered, they are recorded as a regulatory asset or liability, respectively. Our Gas Utilities file periodic monthly, quarterly, semi-annual and/or annual filings to recover these costs based on the respective cost mechanisms approved by their applicable state regulatory commissions.

Gas Price Derivatives - Our regulated Gas Utilities, as allowed or required by state regulatory commissions, have entered into certain exchange-traded natural gas futures and options to reduce our customers' underlying exposure to fluctuations in gas prices. Gas price derivatives represent our unrealized positions on our commodity contracts supporting our utilities. Gas price derivatives at December 31, 2023 are hedged over a maximum forward term of two years.

Deferred Taxes on AFUDC - The equity component of AFUDC is considered a permanent difference for tax purposes with the tax benefit being flowed through to customers as prescribed or allowed by regulators. If, based on a regulator's action, it is probable the utility will recover the future increase in taxes payable represented by this flow-through treatment through a rate revenue increase, a regulatory asset is recognized. This regulatory asset is a temporary difference for which a deferred tax liability must be recognized. Accounting standards for income taxes specifically address AFUDC-equity and require a gross-up of such amounts to reflect the revenue requirement associated with a rate-regulated environment.

Employee Benefit Plans and Related Deferred Taxes - Employee benefit plans include the unrecognized prior service costs and net actuarial loss associated with our defined benefit pension plan and post-retirement benefit plans in regulatory assets rather than in AOCI. In addition, this regulatory asset includes the income tax effect of the adjustment required under accounting for compensation - defined benefit plans, to record the full pension and post-retirement benefit obligations. Such income tax effect has been grossed-up to account for the revenue requirement associated with a rate regulated environment.

Environmental - Environmental costs associated with certain former manufactured gas plant sites. These costs are first offset by recognition of insurance proceeds and settlements with other third parties. Any remaining cost will be requested for recovery in future rate filings. Recovery for these specific environmental costs has not yet been approved by the applicable state regulatory commission and therefore, the recovery period is unknown at this time.

Loss on Reacquired Debt - Loss on reacquired debt is recovered over the remaining life of the original issue or, if refinanced, over the life of the new issue.

Deferred Taxes on Flow-Through Accounting - Under flow-through accounting, the income tax effects of certain tax items are reflected in our cost of service for the customer and result in lower utility rates in the year in which the tax benefits are realized. A regulatory asset was established to reflect that future increases in income taxes payable will be recovered from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record a net tax benefit for costs considered currently deductible for tax purposes but are capitalized for book purposes.

Decommissioning Costs - South Dakota Electric and Colorado Electric received approval in 2014 for recovery of the remaining net book values and decommissioning costs of their decommissioned coal plants. In 2018, Arkansas Gas received approval to record Liquefied Natural Gas Plant decommissioning costs as a regulatory asset and received approval in 2020 to begin recovering those costs over three years.

Regulatory liabilities represent items we expect to refund to customers through probable future decreases in rates.

Deferred Energy and Gas Costs **-** Deferred energy and gas costs that have been over-recovered through customer rates and will be returned to customers in future periods.

Employee Benefit Plans and Related Deferred Taxes **-** Employee benefit plans represent the cumulative excess of pension and retiree healthcare costs recovered in rates over pension expense recorded in accordance with ASC 715, *Compensation-Retirement Benefits*. In addition, this regulatory liability includes the income tax effect of the adjustment required under ASC 715, *Compensation-Retirement Benefits*, to record the full pension and post-retirement benefit obligations. Such income tax effect has been grossed-up to account for the revenue requirement associated with a rate regulated environment.

Cost of Removal **-** Cost of removal represents the estimated cumulative net provisions for future removal costs for which there is no legal obligation for removal included in depreciation expense.

Excess Deferred Income Taxes - The revaluation of the regulated utilities' deferred tax assets and liabilities due to the passage of the TCJA was recorded as excess deferred income taxes to be refunded to customers primarily using the normalization principles as prescribed in the TCJA. A majority of the excess deferred taxes are subject to the average rate assumption method, as prescribed by the IRS, and will generally be amortized as a reduction of customer rates over the remaining lives of the related assets.

Recent Regulatory Activity

Arkansas Gas

On December 4, 2023, Arkansas Gas filed a rate review with the APSC seeking recovery of significant infrastructure investments in its 7,200-mile natural gas pipeline system. The rate review requests $44.1 million in new annual revenue with a capital structure of 48% equity and 52% debt and a return on equity of 10.5%. The request seeks to finalize rates in the fourth quarter of 2024.

Colorado Gas

RMNG Rate Review

On July 12, 2023, the CPUC approved a settlement agreement for RMNG's rate review filed on October 7, 2022. The agreement is expected to generate $8.2 million in new annual revenue and established a weighted average cost of capital of 6.93% with a capital structure that reflects an equity range of 50% to 52% and a debt range of 50% to 48% and a return on equity range of 9.5% to 9.7%. The settlement also shifted $8.3 million of SSIR revenue to base rates and terminated the SSIR. New rates were effective July 15, 2023.

Colorado Gas Rate Review

On May 9, 2023, Colorado Gas filed a rate review with the CPUC seeking recovery of significant infrastructure investments in its 10,000-mile natural gas pipeline system. In the fourth quarter of 2023, Colorado Gas reached a settlement agreement with the CPUC staff and various intervenors for a general rate increase, which is subject to CPUC approval. The settlement is expected to generate $20.2 million of new annual revenue with a capital structure of 50.87% equity and 49.13% debt and a return on equity of 9.3%. If approved, new rates will be effective in February 2024.

Wyoming Gas

On May 18, 2023, Wyoming Gas filed a rate review with the WPSC seeking recovery of significant infrastructure investments in its 6,400-mile natural gas pipeline system. On January 17, 2024, the WPSC approved a settlement agreement for a general rate increase which is expected to generate $13.9 million in new annual revenue with a capital structure of 51% equity and 49% debt and a return on equity of 9.85%. New rates were effective February 1, 2024. The agreement also included approval of a four-year extension of the Wyoming Integrity Rider.

Wyoming Electric

On June 1, 2022, Wyoming Electric filed a rate review with the WPSC seeking recovery of significant infrastructure investments in its 1,330-mile electric distribution and 59-mile electric transmission systems. On January 26, 2023, the WPSC approved a settlement agreement with intervening parties for a general rate increase. The settlement is expected to generate $8.7 million in new annual revenue with a capital structure of 52% equity and 48% debt and a return on equity of 9.75%. New rates were effective March 1, 2023. The agreement also included approval of a new rider that will be filed annually to recover transmission investments and expenses.

(3) COMMITMENTS, CONTINGENCIES AND GUARANTEES

Unconditional Purchase Obligations

We have various PPAs and transmission service agreements, which extend to 2032, to support our Electric Utilities' capacity and energy needs beyond our regulated power plants' generation.

Our Utilities purchase natural gas, including transportation and storage capacity, to meet customers' needs under short-term and long-term purchase contracts. These contracts extend to 2044.

The following is a schedule of unconditional purchase obligations required under the power purchase, transmission services and natural gas transportation and storage agreements (in millions):

	PPAs [(a)]	Transmission Services Agreements	Natural gas supply, transportation and storage agreements
Future commitments for the year ending December 31,			
2024	$ 2.7	$ 12.2	$ 163.0
2025	—	—	135.0
2026	—	—	110.8
2027	—	—	79.5
2028	—	—	58.0
Thereafter	—	—	95.2
Total future commitments	$ 2.7	$ 12.2	$ 641.5

(a) This schedule does not reflect renewable energy PPA future obligations since these agreements vary based on weather conditions.

Lease Agreements

Lessee

We lease from third parties certain office and operation center facilities, communication tower sites, equipment and materials storage. Our leases have remaining terms ranging from less than one year to 32 years, including options to extend that are reasonably certain to be exercised. Our operating and finance leases were not material to the Company’s Consolidated Financial statements.

Lessor

We lease to third parties certain generating station ground leases, communication tower sites and a natural gas pipeline. These leases have remaining terms ranging from less than one year to 31 years. Lease revenue was not material for the years ended December 31, 2023, 2022 and 2021.

As of December 31, 2023, scheduled maturities of operating lease payments to be received in future years were as follows (in millions):

	Operating Leases
2024	$ 2.2
2025	2.2
2026	2.0
2027	1.9
2028	1.9
Thereafter	48.3
Total lease receivables	$ 58.5

Environmental Matters

We are subject to costs resulting from a number of federal, state and local laws and regulations which affect future planning and existing operations. Laws and regulations can result in increased capital expenditures, operating and other costs as a result of compliance, remediation and monitoring obligations. Due to the environmental issues discussed below, we may be required to modify, curtail, replace or cease operating certain facilities or operations to comply with statutes, regulations and other requirements of regulatory bodies.

Reclamation Liability

For our Pueblo Airport Generation site, we posted a bond with the State of Colorado to cover the costs of remediation for a waste water containment pond permitted to provide wastewater storage and processing for this zero-discharge facility. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land.

Under our land leases for our wind generation facilities, we are required to reclaim land where we have placed wind turbines. The reclamation liabilities are recorded at the present value of the estimated future cost to reclaim the land.

Under its mining permit, WRDC is required to reclaim all land where it has mined reserves. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land.

See Note 7 for additional information.

Manufactured Gas Plant

In 2008, we acquired whole and partial liabilities for former manufactured gas plant sites in Nebraska and Iowa, which were previously used to convert coal to natural gas. The acquisition provided for an insurance recovery, now valued at $1.4 million recorded in Other assets, non-current on our Consolidated Balance Sheets, which will be used to help offset remediation costs. We also have a $2.7 million regulatory asset for manufactured gas plant sites; see Note 2 for additional information. As of December 31, 2023, we had $4.1 million and $0.6 million accrued for remediation of the manufactured gas plant sites in Iowa and Nebraska, respectively. Iowa's liabilities are included in Accrued Liabilities and Nebraska's liabilities are included in Other deferred credits and other liabilities on our Consolidated Balance Sheets. The remediation cost estimate could change materially due to results of further investigations, actions of environmental agencies or the financial viability of other responsible parties.

Contingencies and Legal Proceedings

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in the consolidated financial statements to satisfy alleged liabilities are adequate in light of the probable and estimable contingencies. However, there can be no assurance that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims and other matters discussed, and to comply with applicable laws and regulations will not exceed the amounts reflected in the consolidated financial statements.

We record gain contingencies when realized and expected recoveries under applicable insurance contracts when we are assured of recovery.

GT Resources, LLC v. Black Hills Corporation, Case No. 2020CV30751 (U.S. District Court for the City and County of Denver, Colorado)

On April 13, 2022, a jury awarded $41 million for claims made by GT Resources, LLC (“GTR”) against BHC and two of its subsidiaries (Black Hills Exploration and Production, Inc. and Black Hills Gas Resources, Inc.), which ceased oil and natural gas operations in 2018 as part of BHC’s decision to exit the exploration and production business. The claims involved a dispute over a 2.3 million-acre concession award in Costa Rica which was acquired by a BHC subsidiary in 2003. GTR retained rights to receive a royalty interest on any hydrocarbon production from the concession upon the occurrence of contingent events. GTR contended that BHC and its subsidiaries failed to adequately pursue the opportunity and failed to transfer the concession to GTR. We appealed this verdict to the Colorado Court of Appeals. On October 19, 2023, the Appellate Court reversed and remanded the case with directions limiting any retrial to the narrow issue of whether there was improper interference with the prospective conveyance of the concession. We continue to believe this lawsuit has no merit and will vigorously defend it. At this time, we do not believe any losses from this matter will have a material impact on our financial position, results of operations and cash flows.

Gain Contingency -- Wygen 1 Business Interruption Insurance Recovery

In September 2021, Wygen I experienced an unplanned outage that continued until December 2021. For the year ended December 31, 2021, the outage resulted in lost revenues at our subsidiaries Black Hills Wyoming and WRDC. A claim for these losses was submitted under our business interruption insurance policy. During the third quarter of 2023 we recovered $5.0 million from our business interruption insurance, which was recognized as Revenue in our Consolidated Statements of Income for year ended December 31, 2023.

Indemnification

In the normal course of business, we enter into agreements that include indemnification in favor of third parties, such as information technology agreements, purchase and sale agreements and lease contracts. We have also agreed to indemnify our directors, officers and employees in accordance with our articles of incorporation, as amended. Certain agreements do not contain any limits on our liability and therefore, it is not possible to estimate our potential liability under these indemnifications. In certain cases, we have recourse against third parties with respect to these indemnities. Further, we maintain insurance policies that may provide coverage against certain claims under these indemnities.

Guarantees

We have entered into various parent company-level guarantees providing financial or performance assurance to third parties on behalf of certain of our subsidiaries. These guarantees do not represent incremental consolidated obligations, but rather, represent guarantees of subsidiary obligations to allow those subsidiaries to conduct business without posting other forms of assurance. The agreements, which are off-balance sheet commitments, include support for business operations, indemnification for reclamation and surety bonds. The guarantees were entered into in the normal course of business. To the extent liabilities are incurred as a result of activities covered by these guarantees, such liabilities are included in our Consolidated Balance Sheets.

We had the following guarantees in place as of (in millions):

Nature of Guarantee	Maximum Exposure at December 31, 2023
Indemnification for reclamation/surety bonds	$ 100.9
Guarantees supporting business transactions	462.9
Total guarantees	$ 563.8

(4) REVENUE

The following tables depict the disaggregation of revenue, including intercompany revenue, from contracts with customers by customer type and timing of revenue recognition for each of the reportable segments, for the years ended December 31, 2023, 2022 and 2021. Sales tax and other similar taxes are excluded from revenues.

Year ended December 31, 2023	Electric Utilities	Gas Utilities	Inter-segment Eliminations	Total
Customer types:		(in millions)		
Retail	$ 697.7	$ 1,248.8	$ —	$ 1,946.5
Transportation	—	176.8	(0.5)	176.3
Wholesale	34.2	—	—	34.2
Market - off-system sales	50.9	0.4	—	51.3
Transmission/Other	71.4	39.4	(17.4)	93.4
Revenue from contracts with customers	854.2	1,465.4	(17.9)	2,301.7
Other revenues	10.8	18.8	—	29.6
Total revenues	$ 865.0	$ 1,484.2	$ (17.9)	$ 2,331.3
Timing of revenue recognition:				
Services transferred at a point in time	$ 31.5	$ —	$ —	$ 31.5
Services transferred over time	822.7	1,465.4	(17.9)	2,270.2
Revenue from contracts with customers	$ 854.2	$ 1,465.4	$ (17.9)	$ 2,301.7

Year ended December 31, 2022	Electric Utilities	Gas Utilities	Inter-segment Eliminations	Total
Customer types:		(in millions)		
Retail	$ 739.7	$ 1,453.3	$ —	$ 2,193.0
Transportation	—	173.3	(0.4)	172.9
Wholesale	44.8	—	—	44.8
Market - off-system sales	48.6	0.8	—	49.4
Transmission/Other	61.5	37.9	(16.6)	82.8
Revenue from contracts with customers	894.6	1,665.3	(17.0)	2,542.9
Other revenues	5.6	3.8	(0.5)	8.9
Total revenues	$ 900.2	$ 1,669.1	$ (17.5)	$ 2,551.8
Timing of revenue recognition:				
Services transferred at a point in time	$ 30.4	$ —	$ —	$ 30.4
Services transferred over time	864.2	1,665.3	(17.0)	2,512.5
Revenue from contracts with customers	$ 894.6	$ 1,665.3	$ (17.0)	$ 2,542.9

Year ended December 31, 2021	Electric Utilities	Gas Utilities	Inter-segment Eliminations	Total
Customer types:		(in millions)		
Retail	$ 711.5	$ 913.7	$ —	$ 1,625.2
Transportation	—	158.1	(0.4)	157.7
Wholesale	30.8	—	—	30.8
Market - off-system sales	41.7	0.4	—	42.1
Transmission/Other	52.9	39.4	(17.2)	75.1
Revenue from contracts with customers	836.9	1,111.6	(17.6)	1,930.9
Other revenues	5.3	13.3	(0.4)	18.2
Total revenues	$ 842.2	$ 1,124.9	$ (18.0)	$ 1,949.1
Timing of revenue recognition:				
Services transferred at a point in time	$ 27.1	$ —	$ —	$ 27.1
Services transferred over time	809.8	1,111.6	(17.6)	1,903.8
Revenue from contracts with customers	$ 836.9	$ 1,111.6	$ (17.6)	$ 1,930.9

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(5) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment at December 31 consisted of the following (dollars in millions):

	2023		2022		Lives (in years)	
Electric Utilities	**Property, Plant and Equipment**	**Weighted Average Useful Life (in years)**	**Property, Plant and Equipment**	**Weighted Average Useful Life (in years)**	**Minimum**	**Maximum**
Electric plant:						
Production	$ 1,492.8	40	$ 1,482.1	41	32	45
Electric transmission	737.4	48	632.9	48	42	51
Electric distribution	1,146.9	47	1,082.5	47	45	50
Integrated Generation	720.0	30	713.5	31	19	38
Plant acquisition adjustment [(a)]	4.9	32	4.9	32	32	32
General	291.7	27	274.8	27	24	28
Total electric plant in service	4,393.7		4,190.7			
Construction work in progress	123.1		153.0			
Total electric plant	4,516.8		4,343.7			
Less accumulated depreciation and depletion	(1,207.7)		(1,104.1)			
Electric plant net of accumulated depreciation and depletion	$ 3,309.1		$ 3,239.6			

(a) The plant acquisition adjustment, which relates to the acquisition of our ownership interest in Wyodak Plant, is included in rate base and is being recovered with 7 years remaining.

	2023		2022		Lives (in years)	
Gas Utilities	**Property, Plant and Equipment**	**Weighted Average Useful Life (in years)**	**Property, Plant and Equipment**	**Weighted Average Useful Life (in years)**	**Minimum**	**Maximum**
Gas plant:						
Production	$ 21.0	45	$ 17.8	45	24	47
Gas transmission	759.5	58	695.4	58	32	72
Gas distribution	2,860.0	57	2,620.2	57	48	61
Cushion gas - not depreciable [(a)]	58.2	N/A	63.1	N/A	N/A	N/A
Storage	71.4	42	65.8	41	36	49
General	571.8	22	497.4	23	20	25
Total gas plant in service	4,341.9		3,959.7			
Construction work in progress	39.2		52.0			
Total gas plant	4,381.1		4,011.7			
Less accumulated depreciation	(588.3)		(471.0)			
Gas plant net of accumulated depreciation	$ 3,792.8		$ 3,540.7			

(a) Depreciation of Cushion Gas is determined by the respective regulatory jurisdiction in which the Cushion Gas resides. In 2022, assets classified as Cushion gas - depreciable were fully depreciated and removed from gross plant in service and accumulated depreciation.

	2023		2022		Lives (in years)	
Corporate	**Property, Plant and Equipment**	**Weighted Average Useful Life (in years)**	**Property, Plant and Equipment**	**Weighted Average Useful Life (in years)**	**Minimum**	**Maximum**
Total plant in service	$ 5.7	10	$ 5.7	11	4	23
Construction work in progress	13.6		13.7			
Total gross property, plant and equipment	19.3		19.4			
Less accumulated depreciation	(1.9)		(1.8)			
Total net of accumulated depreciation	$ 17.4		$ 17.6			

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(6) JOINTLY OWNED FACILITIES

Our consolidated financial statements include our share of several jointly-owned facilities as described below. Our share of the facilities' expenses is reflected in the appropriate categories of operating expenses in the Consolidated Statements of Income. Each owner of the facility is responsible for financing its investment in the jointly-owned facilities.

At December 31, 2023, our interests in jointly-owned generating facilities and transmission systems were (in millions):

	Ownership Interest	Plant in Service	Construction Work in Progress	Less Accumulated Depreciation	Plant Net of Accumulated Depreciation
Wyodak Plant [(a)]	20 %	$ 122.3	$ —	$ (73.4)	$ 48.9
Transmission Tie	35 %	$ 24.5	$ 0.3	$ (7.8)	$ 17.0
Wygen III [(b)]	52 %	$ 145.3	$ 0.3	$ (32.2)	$ 113.4
Wygen I [(c)]	76.5 %	$ 116.0	$ 0.8	$ (60.1)	$ 56.7

(a) In addition to supplying South Dakota Electric with coal for its share of the Wyodak Plant, our mine supplies PacifiCorp's share of the coal under a separate long-term agreement through December 31, 2026, with an annual renewal option for one-year extensions. This coal supply agreement is collateralized by a mortgage on and a security interest in some of WRDC's coal reserves.
(b) South Dakota Electric retains responsibility for plant operations. WRDC supplies fuel to Wygen III for the life of the plant.
(c) Black Hills Wyoming retains responsibility for plant operations. WRDC supplies fuel to Wygen I for the life of the plant.

(7) ASSET RETIREMENT OBLIGATIONS

We have identified legal obligations related to reclamation of mining sites; removal of fuel tanks, transformers containing polychlorinated biphenyls, an evaporation pond; and reclamation of wind turbine sites at our Electric Utilities segment. In addition, we have identified legal obligations related to retirement of gas pipelines, wells and compressor stations at our Gas Utilities and removal of asbestos at our Utilities. We periodically review and update estimated costs related to these AROs. The actual cost may vary from estimates due to regulatory requirements, changes in technology and increased labor, materials and equipment costs.

The following tables present the details of AROs which are included on the accompanying Consolidated Balance Sheets in Other deferred credits and other liabilities (in millions):

	December 31, 2022	Liabilities Incurred	Liabilities Settled	Accretion	Revisions to Prior Estimates	December 31, 2023
Electric Utilities	$ 27.6	$ —	$ —	$ 1.2	$ (0.1)	$ 28.7
Gas Utilities [(a)]	61.3	6.7	—	2.3	(2.8)	67.5
Total	$ 88.9	$ 6.7	$ —	$ 3.5	$ (2.9)	$ 96.2

	December 31, 2021	Liabilities Incurred	Liabilities Settled	Accretion	Revisions to Prior Estimates	December 31, 2022
Electric Utilities	$ 30.1	$ —	$ (3.0)	$ 1.4	$ (0.9)	$ 27.6
Gas Utilities [(a)]	45.5	—	(0.2)	2.0	14.0	61.3
Total	$ 75.6	$ —	$ (3.2)	$ 3.4	$ 13.1	$ 88.9

(a) The Revisions to Prior Estimates were primarily driven by changes in estimates associated with natural gas wells and compressor stations.

We also have legally required AROs related to certain assets within our electric transmission and distribution systems. These retirement obligations are pursuant to an easement or franchise agreement and are only required if we discontinue our utility service under such easement or franchise agreement. Accordingly, it is not possible to estimate a time period when these obligations could be settled, and therefore, a liability for the cost of these obligations cannot be measured at this time.

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(8) FINANCING

Shelf Registration Statement

We maintain an effective shelf registration statement with the SEC under which we may issue, from time to time, an unspecified amount of senior debt securities, subordinate debt securities, common stock, preferred stock, warrants and other securities. In anticipation of the approaching expiration of our previous shelf registration statement on Form S-3 originally filed on August 4, 2020 (Registration No. 333-240320), we filed a new shelf registration statement on Form S-3 on June 16, 2023 (Registration No. 333-272739).

Short-term debt

Revolving Credit Facility and CP Program

On May 9, 2023, we amended and restated our corporate Revolving Credit Facility, which replaced LIBOR as a benchmark interest rate with the SOFR. The adoption of SOFR as a benchmark interest rate was in advance of the scheduled elimination of LIBOR as a benchmark interest rate on June 30, 2023. No other significant terms or conditions, including borrowing capacity, credit spreads or financial covenants were modified under these amendments and restatements.

We have a $750 million Revolving Credit Facility that matures on July 19, 2026, with two one-year extension options (subject to consent from lenders). This facility includes an accordion feature that allows us to increase total commitments up to $1.0 billion with the consent of the administrative agent, the issuing agents and each bank increasing or providing a new commitment. Borrowings continue to be available under a base rate or various SOFR rate options. The interest costs associated with the letters of credit or borrowings and the commitment fee under the Revolving Credit Facility are determined based upon our Corporate credit rating from S&P, Fitch and Moody's for our senior unsecured long-term debt. Based on our current credit ratings, the margins for base rate borrowings, SOFR borrowings and letters of credit were 0.125%, 1.125% and 1.125%, respectively, at December 31, 2023. Based on our credit ratings, the commitment fee on unused amounts was 0.175%.

We have a $750 million, unsecured CP Program that is backstopped by the Revolving Credit Facility. Amounts outstanding under the Revolving Credit Facility and the CP Program, either individually or in the aggregate, cannot exceed $750 million. The notes issued under the CP Program may have maturities not to exceed 397 days from the date of issuance and bear interest (or are sold at par less a discount representing an interest factor) based on, among other things, the size and maturity date of the note, the frequency of the issuance and our credit ratings. Under the CP Program, any borrowings rank equally with our unsecured debt. Notes under the CP Program are not registered and are offered and issued pursuant to a registration exemption.

Our Revolving Credit Facility and CP Program, which are classified as Notes payable on the Consolidated Balance Sheets, had the following borrowings, outstanding letters of credit, and available capacity at December 31 (dollars in millions):

	2023	2022
Amount outstanding	$ —	$ 535.6
Letters of credit [(a)]	3.7	24.6
Available capacity	746.3	189.8
Weighted average interest rates	N/A	4.88 %

(a) Letters of credit are off-balance sheet commitments that reduce the borrowing capacity available on our corporate Revolving Credit Facility.

Revolving Credit Facility and CP Program borrowing activity for the years ended December 31 was as follows (in millions):

	2023	2022
Maximum amount outstanding (based on daily outstanding balances)	$ 548.7	$ 572.3
Average amount outstanding (based on daily outstanding balances)	81.7	390.7
Weighted average interest rates	4.91 %	2.11 %

Deferred Financing Costs on the Revolving Credit Facility

Total accumulated deferred financing costs on the Revolving Credit Facility of $8.9 million are being amortized over its estimated useful life and were included in Interest expense on the accompanying Consolidated Statements of Income. See below for additional details.

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Long-term debt

Long-term debt outstanding was as follows (dollars in millions):

	Due Date	Interest Rate at December 31, 2023	Balance Outstanding December 31, 2023	Balance Outstanding December 31, 2022
Corporate				
Senior unsecured notes due 2023	November 30, 2023	N/A	$ —	$ 525.0
Senior unsecured notes due 2024	August 23, 2024	1.04%	600.0	600.0
Senior unsecured notes due 2026	January 15, 2026	3.95%	300.0	300.0
Senior unsecured notes due 2027	January 15, 2027	3.15%	400.0	400.0
Senior unsecured notes due 2028	March 15, 2028	5.95%	350.0	—
Senior unsecured notes, due 2029	October 15, 2029	3.05%	400.0	400.0
Senior unsecured notes, due 2030	June 15, 2030	2.50%	400.0	400.0
Senior unsecured notes due 2033	May 1, 2033	4.35%	400.0	400.0
Senior unsecured notes due 2034	May 15, 2034	6.15%	450.0	—
Senior unsecured notes, due 2046	September 15, 2046	4.20%	300.0	300.0
Senior unsecured notes, due 2049	October 15, 2049	3.88%	300.0	300.0
Total Corporate debt			3,900.0	3,625.0
Less unamortized debt discount			(8.9)	(5.3)
Total Corporate debt, net			3,891.1	3,619.7
South Dakota Electric				
First Mortgage Bonds due 2032	August 15, 2032	7.23%	75.0	75.0
First Mortgage Bonds due 2039	November 1, 2039	6.13%	180.0	180.0
First Mortgage Bonds due 2044	October 20, 2044	4.43%	85.0	85.0
Total South Dakota Electric debt			340.0	340.0
Less unamortized debt discount			(0.1)	(0.1)
Total South Dakota Electric debt, net			339.9	339.9
Wyoming Electric				
Industrial development revenue bonds due 2027[(a) (b)]	March 1, 2027	3.93%	10.0	10.0
First Mortgage Bonds due 2037	November 20, 2037	6.67%	110.0	110.0
First Mortgage Bonds due 2044	October 20, 2044	4.53%	75.0	75.0
Total Wyoming Electric debt			195.0	195.0
Less unamortized debt discount			—	—
Total Wyoming Electric debt, net			195.0	195.0
Total long-term debt			4,426.0	4,154.6
Less current maturities			(600.0)	(525.0)
Less unamortized deferred financing costs [(c)]			(24.8)	(22.3)
Long-term debt, net of current maturities and deferred financing costs			$ 3,801.2	$ 3,607.3

(a) Variable interest rate.
(b) A reimbursement agreement is in place with Wells Fargo on behalf of Wyoming Electric for the $10 million bonds due March 1, 2027. In the case of default, we hold the assumption of liability for drawings on Wyoming Electric's Letter of Credit attached to these bonds.
(c) Includes deferred financing costs associated with our Revolving Credit Facility of $1.1 million and $1.8 million as of December 31, 2023 and December 31, 2022, respectively.

Scheduled maturities of long-term debt and associated interest payments by year are shown below (in millions):

	Payments Due by Period						
	2024	2025	2026	2027	2028	Thereafter	Total
Principal payments on Long-term debt including current maturities [(a)]	$ 600.0	$ —	$ 300.0	$ 410.0	$ 350.0	$ 2,775.0	$ 4,435.0
Interest payments on Long-term debt [(a)]	179.0	168.1	162.2	149.6	132.9	1,052.2	1,844.0

(a) Long-term debt amounts do not include deferred financing costs or discounts or premiums on debt. Estimated interest payments on variable rate debt are calculated by utilizing the applicable rates as of December 31, 2023.

Our debt securities contain certain restrictive financial covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2023. See below for additional information.

Substantially all of the tangible utility property of South Dakota Electric and Wyoming Electric is subject to the lien of indentures securing their first mortgage bonds. First mortgage bonds of South Dakota Electric and Wyoming Electric may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures.

Debt Transactions

On September 15, 2023, we completed a public debt offering of $450 million, 6.15% senior unsecured notes due May 15, 2034. Proceeds from the offering, which were net of $7.6 million of deferred financing costs, along with available cash were used to repay all of our $525 million principal amount outstanding notes on their November 30, 2023 maturity date and for other general corporate purposes.

On March 7, 2023, we completed a public debt offering of $350 million, 5.95% five year senior unsecured notes due March 15, 2028. The proceeds from the offering, which were net of $4.2 million of deferred financing costs, were used to repay notes outstanding under our CP Program and for other general corporate purposes.

Debt Covenants

Revolving Credit Facility

We were in compliance with all of our Revolving Credit Facility covenants as of December 31, 2023. We are required to maintain a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.65 to 1.00. Subject to applicable cure periods, a violation of this covenant would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding. As of December 31, 2023, our Consolidated Indebtedness to Capitalization Ratio was 0.58 to 1.00.

Wyoming Electric

Wyoming Electric was in compliance with all covenants within its financing agreements as of December 31, 2023. Wyoming Electric is required to maintain a debt to capitalization ratio of no more than 0.60 to 1.00. As of December 31, 2023, Wyoming Electric's debt to capitalization ratio was 0.51 to 1.00.

Dividend Restrictions

Our Revolving Credit Facility and other debt obligations contain restrictions on the payment of cash dividends when a default or event of default occurs.

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our shareholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries.

Our Utilities are generally limited to the amount of dividends allowed to be paid to our utility holding company under the Federal Power Act and settlement agreements with state regulatory jurisdictions. As of December 31, 2023, the amount of restricted net assets at our Utilities that may not be distributed to our utility holding company in the form of a loan or dividend was approximately $142.6 million.

South Dakota Electric and Wyoming Electric are generally limited to the amount of dividends allowed to be paid to our utility holding company under certain financing agreements.

Equity

Although our aforementioned shelf registration statement does not limit our issuance capacity, our ability to issue securities is limited to the authority granted by our Board of Directors, certain covenants in our financing arrangements and restrictions imposed by federal and state regulatory authorities. Our articles of incorporation authorize the issuance of 100 million shares of common stock and 25 million shares of preferred stock. As of December 31, 2023, we had approximately 68 million shares of common stock outstanding and no shares of preferred stock outstanding.

At-the-Market Equity Offering Program

As previously disclosed, on August 4, 2020, we entered into an Amended and Restated Equity Distribution Sales Agreement ("Previous Sales Agreement") to sell shares of common stock up to an aggregate of $400 million, from time to time, through our ATM program utilizing our shelf registration statement. In conjunction with the new shelf registration statement filing discussed above, we entered into a new Equity Distribution Sales Agreement ("Sales Agreement") on June 16, 2023. We also terminated the Previous Sales Agreement on June 16, 2023. The Sales Agreement is similar to the Previous Sales Agreement and allows us to sell shares of common stock up to an aggregate of $400 million through our ATM program.

ATM activity for the years ended December 31 was as follows (in millions, except Average price per share amounts):

	December 31, 2023	December 31, 2022	December 31, 2021
August 4, 2020 ATM Program			
Proceeds, (net of issuance costs of $(0.5), $(0.9) and $(1.1), respectively)	$ 48.5	$ 90.3	$ 118.8
Number of shares issued	0.8	1.3	1.8
June 16, 2023 ATM Program			
Proceeds, (net of issuance costs of $(0.7), $0, $0, respectively	$ 70.2	$ —	$ —
Number of shares issued	1.2	—	—
Total activity under both ATM Programs			
Proceeds, (net of issuance costs of $(1.2), $(0.9) and $(1.1), respectively)	$ 118.7	$ 90.3	$ 118.8
Number of shares issued	2.0	1.3	1.8
Average price per share	$ 59.04	$ 69.74	$ 66.18

Shareholder Dividend Reinvestment and Stock Purchase Plan

Effective as of July 7, 2023, we terminated our DRSPP. On July 10, 2023, we filed a post-effective amendment to amend the Registration Statement on Form S-3 (File No. 333-240319) filed with the SEC on August 4, 2020. The filing of this post-effective amendment de-registered all shares of common stock that were issuable under the DRSPP but not sold as of July 7, 2023. With the termination of the DRSPP, a direct stock purchase plan is being offered which will allow shareholders to continue making share transactions. This plan is sponsored and administered solely by EQ Shareowner Services, our transfer agent.

(9) RISK MANAGEMENT AND DERIVATIVES

Market and Credit Risk Disclosures

Our activities in the energy industry expose us to a number of risks in the normal operations of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk.

Market Risk

Market risk is the potential loss that may occur as a result of an adverse change in market price, rate or supply. We are exposed, but not limited to, the following market risks:

- Commodity price risk associated with our retail natural gas and wholesale electric power marketing activities and our fuel procurement for several of our gas-fired generation assets, which include market fluctuations due to unpredictable factors such as the COVID-19 pandemic, weather (e.g. Winter Storm Uri), geopolitical events, market speculation, recession, inflation, pipeline constraints, and other factors that may impact natural gas and electric supply and demand; and

- Interest rate risk associated with future debt, including reduced access to liquidity during periods of extreme capital markets volatility, such as the 2008 financial crisis and the COVID-19 pandemic.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty.

We attempt to mitigate our credit exposure by conducting business primarily with high credit quality entities, setting tenor and credit limits commensurate with counterparty financial strength, obtaining master netting agreements and mitigating credit exposure with less creditworthy counterparties through parental guarantees, cash collateral requirements, letters of credit and other security agreements.

We perform periodic credit evaluations of our customers and adjust credit limits based upon payment history and the customer's current creditworthiness, as determined by review of their current credit information. We maintain a provision for estimated credit losses based upon historical experience, changes in current market conditions, expected losses and any specific customer collection issue that is identified. Our credit exposure at December 31, 2023 was concentrated primarily among retail utility customers, investment grade companies, cooperative utilities and federal agencies.

Derivatives and Hedging Activity

Our derivative and hedging activities included in the accompanying Consolidated Balance Sheets, Consolidated Statements of Income and Consolidated Statements of Comprehensive Income (Loss) are detailed below and within Note 10.

The operations of our Utilities, including natural gas sold by our Gas Utilities and natural gas used by our Electric Utilities' generation plants or those plants under PPAs where our Electric Utilities must provide the generation fuel (tolling agreements), expose our utility customers to natural gas price volatility. Therefore, as allowed or required by state utility commissions, we have entered into commission approved hedging programs utilizing natural gas futures, options, over-the-counter swaps and basis swaps to reduce our customers' underlying exposure to these fluctuations. These transactions are considered derivatives, and in accordance with accounting standards for derivatives and hedging, mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets, net of balance sheet offsetting as permitted by GAAP.

For our regulated Utilities' hedging plans, unrealized and realized gains and losses, as well as option premiums and commissions on these transactions are recorded as Regulatory assets or Regulatory liabilities in the accompanying Consolidated Balance Sheets in accordance with state regulatory commission guidelines. When the related costs are recovered through our rates, the hedging activity is recognized in the Consolidated Statements of Income.

We periodically have wholesale power purchase and sale contracts used to manage purchased power costs and load requirements associated with serving our electric customers that are considered derivative instruments due to not qualifying for the normal purchase and normal sales exception to derivative accounting. Changes in the fair value of these commodity derivatives are recognized in the Consolidated Statements of Income.

To support our Choice Gas Program customers, we buy, sell and deliver natural gas at competitive prices by managing commodity price risk. As a result of these activities, this area of our business is exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks using over-the-counter and exchange traded options and swaps with counterparties in anticipation of forecasted purchases and sales during time frames ranging from January 2024 through October 2025. A portion of our over-the-counter swaps have been designated as cash flow hedges to mitigate the commodity price risk associated with deliveries under fixed price forward contracts to deliver gas to our Choice Gas Program customers. The gain or loss on these designated derivatives is reported in AOCI in the accompanying Consolidated Balance Sheets and reclassified into earnings in the same period that the underlying hedged item is recognized in earnings. Effectiveness of our hedging position is evaluated at least quarterly.

The contract or notional amounts and terms of the natural gas derivative commodity instruments held by our utilities are comprised of both short and long positions. We had the following net long positions as of:

		December 31, 2023		December 31, 2022	
	Units	Notional Amounts	Maximum Term (months) [(a)]	Notional Amounts	Maximum Term (months) [(a)]
Natural gas futures purchased	MMBtus	650,000	3	630,000	3
Natural gas options purchased, net	MMBtus	2,850,000	3	1,790,000	3
Natural gas basis swaps purchased	MMBtus	1,050,000	3	900,000	3
Natural gas over-the-counter swaps, net [(b)]	MMBtus	3,890,000	21	4,460,000	24
Natural gas physical commitments, net [(c)]	MMBtus	12,582,415	10	17,864,412	12

(a) Term reflects the maximum forward period hedged.
(b) As of December 31, 2023, 2,101,700 MMBtus of natural gas over-the-counter swaps purchased were designated as cash flow hedges.
(c) Volumes exclude derivative contracts that qualify for the normal purchase, normal sales exception permitted by GAAP.

We have certain derivative contracts which contain credit provisions. These credit provisions may require the Company to post collateral when credit exposure to the Company is in excess of a negotiated line of unsecured credit. At December 31, 2023, the Company posted $2.0 million related to such provisions, which is included in Other current assets on the Consolidated Balance Sheets.

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Derivatives by Balance Sheet Classification

The following tables present the fair value and balance sheet classification of our derivative instruments as of December 31, (in millions):

	Balance Sheet Location	2023	2022
Derivatives designated as hedges:			
Asset derivative instruments:			
Current commodity derivatives	Derivative assets - current	$ —	$ 0.1
Noncurrent commodity derivatives	Other assets, non-current	—	0.2
Liability derivative instruments:			
Current commodity derivatives	Derivative liabilities - current	(2.7)	(1.7)
Noncurrent commodity derivatives	Other deferred credits and other liabilities	(0.2)	—
Total derivatives designated as hedges		$ (2.9)	$ (1.4)
Derivatives not designated as hedges:			
Asset derivative instruments:			
Current commodity derivatives	Derivative assets - current	$ —	$ 0.5
Noncurrent commodity derivatives	Other assets, non-current	—	0.3
Liability derivative instruments:			
Current commodity derivatives	Derivative liabilities - current	(3.8)	(4.9)
Noncurrent commodity derivatives	Other deferred credits and other liabilities	(0.1)	—
Total derivatives not designated as hedges		$ (3.9)	$ (4.1)

Derivatives Designated as Hedge Instruments

The impact of cash flow hedges on our Consolidated Statements of Comprehensive Income and Consolidated Statements of Income is presented below for the years ended December 31, 2023, 2022 and 2021. Note that this presentation does not reflect the gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic profit or loss we realized when the underlying physical and financial transactions were settled.

Derivatives in Cash Flow Hedging Relationships	2023	2022	2021	Income Statement Location	2023	2022	2021
	Amount of Gain/(Loss) Recognized in OCI				Amount of Gain/(Loss) Reclassified from AOCI into Income		
	(in millions)				(in millions)		
Interest rate swaps	$ 2.9	$ 2.8	$ 2.8	Interest expense	$ (2.9)	$ (2.8)	$ (2.9)
Commodity derivatives	(1.6)	(3.5)	2.0	Fuel, purchased power and cost of natural gas sold	(3.0)	2.7	2.1
Total	$ 1.3	$ (0.7)	$ 4.8		$ (5.9)	$ (0.1)	$ (0.8)

As of December 31, 2023, $5.9 million of net losses related to our interest rate swaps and commodity derivatives are expected to be reclassified from AOCI into earnings within the next 12 months. As market prices fluctuate, estimated and actual realized gains or losses will change during future periods.

Derivatives Not Designated as Hedge Instruments

The following table summarizes the impacts of derivative instruments not designated as hedge instruments on our Consolidated Statements of Income for the years ended December 31, 2023, 2022 and 2021. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	2023	2022	2021
		Amount of Gain/(Loss) on Derivatives Recognized in Income		
		(in millions)		
Commodity derivatives - Natural Gas	Fuel, purchased power and cost of natural gas sold	$ (4.2)	$ (0.8)	$ 2.6
		$ (4.2)	$ (0.8)	$ 2.6

As discussed above, financial instruments used in our regulated Gas Utilities are not designated as cash flow hedges. However, there is no earnings impact because the unrealized gains and losses arising from the use of these financial instruments are recorded as Regulatory assets or Regulatory liabilities. The net unrealized losses included in a Regulatory asset related to these financial instruments used in our Gas Utilities were $5.1 million and $8.8 million at December 31, 2023 and 2022, respectively.

For our Electric Utilities, the unrealized gains and losses arising from these derivatives are recognized in the Consolidated Statements of Income.

(10) FAIR VALUE MEASUREMENTS

Recurring Fair Value Measurements

Derivatives

Valuation methodologies for our derivatives are detailed within Note 1. The following tables set forth, by level within the fair value hierarchy, our gross assets and gross liabilities and related offsetting as permitted by GAAP that were accounted for at fair value on a recurring basis for derivative instruments.

	As of December 31, 2023				
	Level 1	Level 2	Level 3 (in millions)	Cash Collateral and Counterparty Netting [(a)]	Total
Assets:					
Commodity derivatives	$ —	$ 1.9	$ —	$ (1.9)	$ —
Total	$ —	$ 1.9	$ —	$ (1.9)	$ —
Liabilities:					
Commodity derivatives	$ —	$ 10.1	$ —	$ (3.3)	$ 6.8
Total	$ —	$ 10.1	$ —	$ (3.3)	$ 6.8

(a) As of December 31, 2023, $1.9 million of our commodity derivative gross assets and $3.3 million of our commodity derivative gross liabilities, as well as related gross collateral amounts, were subject to master netting agreements.

	As of December 31, 2022				
	Level 1	Level 2	Level 3 (in millions)	Cash Collateral and Counterparty Netting [(a)]	Total
Assets:					
Commodity derivatives	$ —	$ 5.4	$ —	$ (4.3)	$ 1.1
Total	$ —	$ 5.4	$ —	$ (4.3)	$ 1.1
Liabilities:					
Commodity derivatives	$ —	$ 11.4	$ —	$ (4.8)	$ 6.6
Total	$ —	$ 11.4	$ —	$ (4.8)	$ 6.6

(a) As of December 31, 2022, $4.3 million of our commodity derivative assets and $4.8 million of our commodity derivative liabilities, as well as related gross collateral amounts, were subject to master netting agreements.

Pension and Postretirement Plan Assets

A discussion of the fair value of our Pension and Postretirement Plan assets is included in Note 13.

Other Fair Value Measurements

The carrying amount of cash and cash equivalents, restricted cash and equivalents and short-term borrowings approximates fair value due to their liquid or short-term nature. Cash, cash equivalents and restricted cash are classified in Level 1 in the fair value hierarchy. Notes payable consist of commercial paper borrowings and are not traded on an exchange; therefore, they are classified as Level 2 in the fair value hierarchy.

The following table presents the carrying amounts and fair values of financial instruments not recorded at fair value on the Consolidated Balance Sheets at December 31 (in millions):

	2023		2022	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current maturities [(a)]	$ 4,401.2	$ 4,215.6	$ 4,132.3	$ 3,760.8

(a) Long-term debt is valued based on observable inputs available either directly or indirectly for similar liabilities in active markets and therefore is classified in Level 2 in the fair value hierarchy. Carrying amount of long-term debt is net of deferred financing costs.

(11) OTHER COMPREHENSIVE INCOME

We record deferred gains (losses) in AOCI related to interest rate swaps designated as cash flow hedges, commodity contracts designated as cash flow hedges and the amortization of components of our defined benefit plans. Deferred gains (losses) for our commodity contracts designated as cash flow hedges are recognized in earnings upon settlement, while deferred gains (losses) related to our interest rate swaps are recognized in earnings as they are amortized.

The following table details reclassifications out of AOCI and into Net income. The amounts in parentheses below indicate decreases to Net income in the Consolidated Statements of Income for the period, net of tax (in millions):

	Location on the Consolidated Statements of Income	Amount Reclassified from AOCI December 31, 2023	December 31, 2022
Gains and (losses) on cash flow hedges:			
Interest rate swaps	Interest expense	$ (2.9)	$ (2.8)
Commodity contracts	Fuel, purchased power and cost of natural gas sold	(3.0)	2.7
		(5.9)	(0.1)
Income tax	Income tax benefit (expense)	1.4	—
Total reclassification adjustments related to cash flow hedges, net of tax		$ (4.5)	$ (0.1)
Amortization of components of defined benefit plans:			
Prior service cost	Operations and maintenance	$ —	$ 0.1
Actuarial gain (loss)	Operations and maintenance	(0.2)	(0.8)
		(0.2)	(0.7)
Income tax	Income tax benefit (expense)	—	0.2
Total reclassification adjustments related to defined benefit plans, net of tax		$ (0.2)	$ (0.5)
Total reclassifications		$ (4.7)	$ (0.6)

Balances by classification included within AOCI, net of tax on the accompanying Consolidated Balance Sheets were as follows (in millions):

	Derivatives Designated as Cash Flow Hedges			
	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
As of December 31, 2021	$ (10.4)	$ 1.5	$ (11.2)	$ (20.1)
Other comprehensive income (loss) before reclassifications	—	(0.6)	4.6	4.0
Amounts reclassified from AOCI	2.1	(2.1)	0.5	0.5
As of December 31, 2022	$ (8.3)	$ (1.2)	$ (6.1)	$ (15.6)
Other comprehensive income (loss) before reclassifications	—	(3.6)	(0.3)	(3.9)
Amounts reclassified from AOCI	2.2	2.3	0.2	4.7
As of December 31, 2023	$ (6.1)	$ (2.5)	$ (6.2)	$ (14.8)

(12) VARIABLE INTEREST ENTITY

Black Hills Colorado IPP owns and operates a 200 MW, combined-cycle natural gas generating facility located in Pueblo, Colorado. In 2016, Black Hills Electric Generation sold a 49.9%, non-controlling interest in Black Hills Colorado IPP to a third-party buyer. Black Hills Electric Generation is the operator of the facility, which is contracted to provide capacity and energy through 2031 to Colorado Electric.

Net income available for common stock for the years ended December 31, 2023, 2022 and 2021 was reduced by $13.8 million, $12.4 million, and $14.5 million, respectively, attributable to this non-controlling interest. The net income allocable to the non-controlling interest holder is based on ownership interest with the exception of certain agreed upon adjustments. Distributions of net income attributable to this non-controlling interest are due within 30 days following the end of a quarter but may be withheld as necessary by Black Hills Electric Generation.

Black Hills Colorado IPP has been determined to be a VIE in which the Company has a variable interest. Black Hills Electric Generation has been determined to be the primary beneficiary of the VIE as Black Hills Electric Generation is the operator and manager of the generation facility and, as such, has the power to direct the activities that most significantly impact Black Hills Colorado IPP's economic performance. Black Hills Electric Generation, as the primary beneficiary, continues to consolidate Black Hills Colorado IPP. Black Hills Colorado IPP has not received financial or other support from the Company outside of pre-existing contractual arrangements during the reporting period. Black Hills Colorado IPP does not have any debt and its cash flows from operations are sufficient to support its ongoing operations.

We have recorded the following assets and liabilities on our Consolidated Balance Sheets related to the VIE described above as of December 31 (in millions):

	2023	2022
Assets:		
Current assets	$ 15.1	$ 12.8
Property, plant and equipment	$ 166.8	$ 178.8
Liabilities:		
Current liabilities	$ 4.8	$ 5.4

(13) EMPLOYEE BENEFIT PLANS

Defined Contribution Plans

We sponsor a 401(k) retirement savings plan (the 401(k) Plan). Participants in the 401(k) Plan may elect to invest a portion of their eligible compensation in the 401(k) Plan up to the maximum amounts established by the IRS. The 401(k) Plan provides employees the opportunity to invest up to 50% of their eligible compensation on a pre-tax or after-tax basis.

The 401(k) Plan provides a Company matching contribution for all eligible participants. Certain eligible participants who are not currently accruing a benefit in the Pension Plan also receive a Company retirement contribution based on the participant's age and years of service. Vesting of all Company and matching contributions occurs at 20% per year with 100% vesting when the participant has 5 years of service with the Company.

Defined Benefit Pension Plan

We have one defined benefit pension plan, the Black Hills Retirement Plan (Pension Plan). The Pension Plan covers certain eligible employees of the Company. The benefits for the Pension Plan are based on years of service and calculations of average earnings during a specific time period prior to retirement. The Pension Plan is closed to new employees and frozen for certain employees who did not meet age and service-based criteria.

The Pension Plan assets are held in a Master Trust. Our Board of Directors has approved the Pension Plan's investment policy. The objective of the investment policy is to manage assets in such a way that will allow the eventual settlement of our obligations to the Pension Plan's beneficiaries. To meet this objective, our pension assets are managed by an outside adviser using a portfolio strategy that will provide liquidity to meet the Pension Plan's benefit payment obligations. The Pension Plan's assets consist primarily of equity, fixed income and hedged investments.

The expected rate of return on the Pension Plan assets is determined by reviewing the historical and expected returns of both equity and fixed income markets, taking into account asset allocation, the correlation between asset class returns and the mix of active and passive investments. The Pension Plan utilizes a dynamic asset allocation where the target range to return-seeking and liability-hedging assets is determined based on the funded status of the Plan. As of December 31, 2023, the expected rate of return on pension plan assets was based on the targeted asset allocation range of 20% to 28% return-seeking assets and 72% to 80% liability-hedging assets.

Our Pension Plan is funded in compliance with the federal government's funding requirements.

Plan Assets

The percentages of total plan asset by investment category for our Pension Plan at December 31 were as follows:

Return-seeking Assets	2023	2022
Equity	14%	14%
Real estate	5%	7%
Hedge funds	3%	3%
Fixed income	2%	2%
Total	24%	26%

Liability-hedging Assets	2023	2022
Fixed income	74%	72%
Cash	2%	2%
Total	76%	74%
Total Assets	100%	100%

Supplemental Non-qualified Defined Benefit Plans

We have various supplemental retirement plans for key executives of the Company. The plans are non-qualified defined benefit and defined contribution plans (Supplemental Plans). The Supplemental Plans are subject to various vesting schedules and are funded on a cash basis as benefits are paid.

Non-pension Defined Benefit Postretirement Healthcare Plan

BHC sponsors a retiree healthcare plan (Healthcare Plan) for employees who meet certain age and service requirements at retirement. Healthcare Plan benefits are subject to premiums, deductibles, co-payment provisions and other limitations. A portion of the Healthcare Plan for participating business units are pre-funded via VEBA trusts. Pre-65 retirees as well as a grandfathered group of post-65 retirees receive their retiree medical benefits through the Black Hills self-insured retiree medical plans.

Healthcare coverage for post-65 Medicare-eligible retirees is provided through an individual market healthcare exchange. We fund the Healthcare Plan on a cash basis as benefits are paid. The Healthcare Plan provides for partial pre-funding via VEBA trusts. Assets related to this pre-funding are held in trust and are for the benefit of the union and non-union employees located in the states of Arkansas, Iowa and Kansas. We do not pre-fund the Healthcare Plan for those employees outside Arkansas, Iowa and Kansas.

Plan Contributions

Contributions to the Pension Plan are cash contributions made directly to the Master Trust. Healthcare and Supplemental Plan contributions are made in the form of benefit payments. Healthcare benefits include company and participant paid premiums.

Contributions for the years ended December 31 were as follows (in millions):

	2023	2022
Defined Contribution Plan		
Company retirement contributions	$ 12.7	$ 11.9
Company matching contributions	$ 17.1	$ 16.2
Defined Benefit Plans		
Defined Benefit Pension Plan	$ —	$ —
Non-Pension Defined Benefit Postretirement Healthcare Plan	$ 5.4	$ 6.1
Supplemental Non-Qualified Defined Benefit Plans	$ 3.5	$ 3.1

We do not have any required contributions to our Pension Plan in 2024; however, we expect to make $2.3 million in contributions.

Fair Value Measurements

The following tables set forth, by level within the fair value hierarchy, the assets that were accounted for at fair value on a recurring basis (in millions):

	December 31, 2023					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV [(a)]	Total Investments
Pension Plan						
Common Collective Trust - Cash and Cash Equivalents	$ —	$ 6.7	$ —	$ 6.7	$ —	$ 6.7
Common Collective Trust - Equity	—	42.7	—	42.7	—	42.7
Common Collective Trust - Fixed Income	—	234.5	—	234.5	—	234.5
Common Collective Trust - Real Estate	—	—	—	—	16.4	16.4
Hedge Funds	—	—	—	—	8.1	8.1
Total investments measured at fair value	$ —	$ 283.9	$ —	$ 283.9	$ 24.5	$ 308.4
Non-pension Defined Benefit Postretirement Healthcare Plan						
Cash and Cash Equivalents	8.0	—	—	8.0		8.0
Total investments measured at fair value	$ 8.0	$ —	$ —	$ 8.0		$ 8.0

	December 31, 2022					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV [(a)]	Total Investments
Pension Plan						
Common Collective Trust - Cash and Cash Equivalents	$ —	$ 6.4	$ —	$ 6.4	$ —	$ 6.4
Common Collective Trust - Equity	—	45.1	—	45.1	—	45.1
Common Collective Trust - Fixed Income	—	242.0	—	242.0	—	242.0
Common Collective Trust - Real Estate	—	—	—	—	21.5	21.5
Hedge Funds	—	—	—	—	8.1	8.1
Total investments measured at fair value	$ —	$ 293.5	$ —	$ 293.5	$ 29.6	$ 323.1
Non-pension Defined Benefit Postretirement Healthcare Plan						
Cash and Cash Equivalents	7.8	—	—	7.8		7.8
Total investments measured at fair value	$ 7.8	$ —	$ —	$ 7.8		$ 7.8

(a) Certain investments that are measured at fair value using NAV per share (or its equivalent) for practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in these tables for these investments are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the reconciliation of changes in the plan's benefit obligations and fair value of plan assets above.

Additional information about assets of the benefit plans, including methods and assumptions used to estimate the fair value of these assets, is as follows:

Pension Plan

Common Collective Trust Funds: These funds are valued based upon the redemption price of units held by the Pension Plan, which is based on the current fair value of the common collective trust funds' underlying assets. Unit values are determined by the financial institution sponsoring such funds by dividing the fund's net assets at fair value by its units outstanding at the valuation dates. The Pension Plan's investments in common collective trust funds, with the exception of shares of the common collective trust-real estate are categorized as Level 2.

The following investments are measured at NAV and are not classified in the fair value hierarchy, in accordance with accounting guidance:

Common Collective Trust-Real Estate Funds: These funds are valued based on various factors of the underlying real estate properties, including market rent, market rent growth, occupancy levels, etc. As part of the trustee's valuation process, properties are externally appraised generally on an annual basis. The appraisals are conducted by reputable independent appraisal firms and signed by appraisers that are members of the Appraisal Institute, with professional designation of Member, Appraisal Institute. All external appraisals are performed in accordance with the Uniform Standards of Professional Appraisal Practices. We receive monthly statements from the trustee, along with the annual schedule of investments and rely on these reports for pricing the units of the fund.

Hedge Funds: These funds represent investments in other investment funds that seek a return utilizing a number of diverse investment strategies. The strategies, when combined, aim to reduce volatility and risk while attempting to deliver positive returns under all market conditions. Amounts are reported on a one-month lag. The fair value of hedge funds is determined using net asset value per share based on the fair value of the hedge fund's underlying investments. 10% of the shares may be redeemed at the end of each month with a 15-day notice and full redemptions are available at the end of each quarter with 60-day notice and is limited to a percentage of the total net assets value of the fund. The net asset values are based on the fair value of each fund's underlying investments. There are no unfunded commitments related to these hedge funds.

Non-pension Defined Benefit Postretirement Healthcare Plan

Cash and Cash Equivalents: This represents an investment in Northern Institutional Government Assets Portfolio, which is a government money market fund. As shares held reflect quoted prices in an active market, they are categorized as Level 1.

Components of Net Periodic Expense

The following table provides a reconciliation of components of the net periodic expense (in millions):

	Defined Benefit Pension Plan			**Supplemental Non-qualified Defined Benefit Plans**			**Non-pension Defined Benefit Postretirement Healthcare Plan**		
For the years ended December 31,	**2023**	**2022**	**2021**	**2023**	**2022**	**2021**	**2023**	**2022**	**2021**
Service cost	$ 2.5	$ 3.9	$ 5.0	$ 3.1	$ (0.8)	$ 3.1	$ 1.5	$ 1.9	$ 2.2
Interest cost	17.5	10.8	9.3	1.5	0.8	0.7	2.4	1.3	1.0
Expected return on assets	(18.7)	(18.5)	(20.8)	—	—	—	(0.2)	(0.1)	(0.1)
Net amortization of prior service cost	(0.1)	(0.1)	—	—	—	—	—	(0.3)	(0.4)
Recognized net actuarial loss (gain)	2.0	6.1	7.3	—	0.3	1.8	—	0.1	0.5
Net periodic expense	$ 3.2	$ 2.2	$ 0.8	$ 4.6	$ 0.3	$ 5.6	$ 3.7	$ 2.9	$ 3.2

Service costs are recorded in Operations and maintenance expense while non-service costs are recorded in Other expense on the Consolidated Statements of Income.

Actuarial gains and losses are amortized using a straight-line method over the average remaining service period of active plan participants or over the average remaining lifetime of the remaining plan participants if the plan is viewed as "all or almost all" inactive participants.

Other Plan Information

The following tables provide a reconciliation of the employee benefit plan obligations and fair value of employee benefit plan assets, amounts recognized on our Consolidated Balance Sheets, accumulated benefit obligation and elements of AOCI (in millions):

	Defined Benefit Pension Plan	Supplemental Non-qualified Defined Benefit Plans	Non-pension Defined Benefit Postretirement Healthcare Plan	Defined Benefit Pension Plan	Supplemental Non-qualified Defined Benefit Plans	Non-pension Defined Benefit Postretirement Healthcare Plan
		2023			2022	
Accumulated benefit obligation at December 31	$ 341.8	$ 46.7	$ 51.1	$ 350.2	$ 45.2	$ 49.7
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 358.4	$ 45.2	$ 49.7	$ 478.3	$ 55.3	$ 63.5
Service cost	2.5	3.1	1.5	3.9	(0.8)	1.9
Interest cost	17.5	1.5	2.4	10.8	0.8	1.3
Actuarial (gain) loss	11.6	0.3	1.7	(97.9)	(7.0)	(12.3)
Benefits paid	(41.9)	(3.4)	(5.3)	(36.7)	(3.1)	(6.1)
Plan participants' contributions	—	—	1.1	—	—	1.4
Projected benefit obligation at end of year	348.1	46.7	51.1	358.4	45.2	49.7
Change in fair value of plan assets:						
Fair value of plan assets at beginning of year	323.1	—	7.8	458.4	—	8.0
Investment income (loss)	27.4	—	0.2	(98.6)	—	—
Employer contributions	—	3.5	4.3	—	3.1	4.5
Retiree contributions	—	—	1.1	—	—	1.4
Benefits paid	(41.9)	(3.5)	(5.4)	(36.7)	(3.1)	(6.1)
Fair value of plan assets at end of year	308.6	—	8.0	323.1	—	7.8
Funded status - deficiency	$ 39.5	$ 46.7	$ 43.1	$ 35.3	$ 45.2	$ 41.9
Amounts recognized on our Consolidated Balance Sheets as of December 31:						
Regulatory assets	$ 79.9	$ —	$ 4.8	$ 78.7	$ —	$ 3.8
Current liabilities	—	2.4	4.2	—	2.2	4.4
Non-current assets	—	—	1.3	—	—	1.0
Non-current liabilities	39.4	44.3	40.2	35.2	43.0	38.5
Regulatory liabilities	2.9	—	5.5	2.8	—	6.2
Amounts recognized in AOCI, net of tax as of December 31:						
Net (gain) loss	$ 5.0	$ 1.8	$ (0.7)	$ 5.2	$ 1.6	$ (0.7)
Prior service cost (gain)	—	—	0.1	(0.1)	—	0.1
Total amounts included in AOCI, net of tax not yet recognized as components of net periodic expense	$ 5.0	$ 1.8	$ (0.6)	$ 5.1	$ 1.6	$ (0.6)

In 2012, we froze our Pension Plan and closed it to new participants. Since then, we have implemented various de-risking strategies including lump sum buyouts, the purchase of annuities and the reduction of return-seeking assets over time to a more liability-hedged portfolio. As a result, capital markets volatility had a limited impact to our unfunded status.

Assumptions

	Defined Benefit Pension Plan			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plan		
	2023	2022	2021	2023	2022	2021	2023	2022	2021
Weighted-average assumptions used to determine benefit obligations:									
Discount rate	4.99 %	5.17 %	2.88 %	4.93 %	5.13 %	2.77 %	4.97 %	5.14 %	2.79 %
Rate of increase in compensation levels	3.04 %	3.06 %	3.08 %	—	—	5.00 %	N/A	N/A	N/A
Weighted-average assumptions used to determine net periodic benefit cost for plan year:									
Discount rate [(a)]	5.17 %	2.88 %	2.56 %	5.13 %	2.77 %	2.41 %	5.14 %	2.79 %	2.41 %
Expected long-term rate of return on assets [(b)]	6.00 %	4.25 %	4.50 %	N/A	N/A	N/A	3.10 %	1.70 %	1.80 %
Rate of increase in compensation levels	3.06 %	3.08 %	3.34 %	—	—	5.00 %	N/A	N/A	N/A

(a) The estimated discount rate for the Defined Benefit Pension Plan is 5.0% for the calculation of the 2024 net periodic pension costs.
(b) The expected rate of return on plan assets for the Defined Benefit Pension Plan is 6.0% for the calculation of the 2024 net periodic pension cost.

The healthcare benefit obligation at December 31 was determined as follows:

	2023	2022
Trend Rate - Medical		
Pre-65 for next year - All Plans	6.69 %	7.00 %
Pre-65 Ultimate trend rate - Black Hills Corp	4.50 %	4.50 %
Trend Year	2034	2031
Post-65 for next year - All Plans	5.81 %	6.00 %
Post-65 Ultimate trend rate - Black Hills Corp	4.50 %	4.50 %
Trend Year	2034	2031

The following benefit payments to employees, which reflect future service, are expected to be paid (in millions):

	Defined Benefit Pension Plan	Supplemental Non-qualified Defined Benefit Plans	Non-pension Defined Benefit Postretirement Healthcare Plan
2024	$ 24.5	$ 2.4	$ 5.2
2025	25.4	2.8	5.0
2026	26.0	2.8	4.9
2027	25.9	2.7	4.8
2028	26.2	2.6	4.6
2029 - 2033	$ 129.7	$ 11.7	$ 21.4

(14) SHARE-BASED COMPENSATION PLANS

Our Amended and Restated 2015 Omnibus Incentive Plan allows for the granting of stock, restricted stock, restricted stock units, stock options, performance shares and performance share units. We had 2,132,275 shares available to grant at December 31, 2023.

Compensation expense is determined using the grant date fair value estimated in accordance with the provisions of accounting standards for stock compensation and is recognized over the vesting periods of the individual awards. As of December 31, 2023, total unrecognized compensation expense related to non-vested stock awards was $10.6 million and is expected to be recognized over a weighted-average period of 1.7 years. Stock-based compensation expense, which is included in Operations and maintenance on the accompanying Consolidated Statements of Income, was as follows for the years ended December 31 (in millions):

	2023	2022	2021
Stock-based compensation expense	$ 7.0	$ 8.6	$ 9.7

<u>Restricted Stock</u>

The fair value of restricted stock and restricted stock unit awards equals the market price of our stock on the date of grant.

The shares carry a restriction on the ability to sell the shares until the shares vest. The shares substantially vest over three years, contingent on continued employment. Compensation expense related to the awards is recognized over the vesting period.

A summary of the status of the restricted stock and restricted stock units at December 31, 2023, was as follows:

	Restricted Stock	Weighted-Average Grant Date Fair Value
Balance at January 1, 2023	178,129	$ 67.23
Granted	110,198	63.33
Vested	(97,084)	67.56
Forfeited	(26,556)	65.10
Balance at December 31, 2023	164,687	$ 64.81

The weighted-average grant-date fair value of restricted stock granted, and the total fair value of shares vested during the years ended December 31, were as follows:

	Weighted-Average Grant Date Fair Value	Total Fair Value of Shares Vested
		(in millions)
2023	$ 63.33	$ 5.9
2022	$ 69.03	$ 6.4
2021	$ 65.64	$ 5.4

As of December 31, 2023, there was $6.3 million of unrecognized compensation expense related to non-vested restricted stock that is expected to be recognized over a weighted-average period of 1.6 years.

Performance Share Units

Beginning in 2021, certain officers of the Company, and its subsidiaries, were granted performance share units which have a three-year vesting period, do not have voting rights until vested, and are subject to three specified conditions. A market condition of relative total shareholder return and two equally weighted performance metrics of average earnings per share and the average cost to serve. Beginning in 2023, the metric of natural gas emissions reduction by 2035 was added, resulting in three equally weighted performance metrics. The units are paid 100% in common stock should conditions be met and can range from 0% to 200% of the target award. Dividend equivalents are accrued during the vesting period and paid out based on the final number of shares awarded. In the event of participant’s death or retirement at age 55 or older, shares awarded vest on a pro-rata basis commensurate with the months of service performed over the three-year period.

Performance Share Units - Market Condition

The fair value of each share unit is based on the Company’s closing price at December 31 of the year prior to the award and a Monte Carlo simulation. The Monte Carlo simulation is used to estimate expected share payout based on the Company’s TSR for a three-year performance period relative to the designated peer group beginning January 1 of the award year. The significant assumptions included in the company's Monte Carlo simulations were as follows:

	2023	2022
Fair value of share units award	$77.95	$74.48
Risk-free rate	3.84%	0.97%
Black Hills Corporation’s common stock volatility	31%	30%
Volatility range for the peer group	24-39%	22-67%

Performance Share Units - Performance Condition

A performance condition share unit vests at the end of the three-year performance period if the specified performance conditions are achieved. The conditions are based on the Company’s average earnings per share, the average cost to serve and natural gas emissions reductions by 2035. The grant-date fair value for an individual outcome of a performance condition is determined by the closing common share price on the grant date or, beginning in 2023, the average ten-day closing common share price preceding the grant date.

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The following table summarizes the performance share unit activity for the year ended December 31, 2023:

	Performance Share Units - Market Condition		Performance Share Units - Performance Condition	
	Share Units	Weighted-Average Fair Value per Share Unit	Share Units	Weighted-Average Fair Value per Share Unit
Nonvested at January 1, 2023	68,474	$ 69.91	45,666	$ 66.19
Granted	50,440	77.95	21,615	71.50
Forfeited	(8,167)	73.43	(4,627)	68.03
Nonvested at December 31, 2023	110,747	$ 73.31	62,654	$ 67.88

As of December 31, 2023, there was $4.0 million of unrecognized compensation expense related to outstanding performance share/units that is expected to be recognized over a weighted-average period of 1.8 years.

On January 25, 2024, the Compensation Committee of our Board of Directors confirmed a payout equal to 16.21% of target shares valued at $0.5 million. The payout was fully accrued at December 31, 2023.

Performance Share Plan

Prior to 2021, certain officers of the Company and its subsidiaries became participants in a market-based performance share award plan. Performance shares are awarded based on our total shareholder return over designated performance periods as measured against a selected peer group. In addition, certain stock price performance must be achieved for a payout to occur. The final value of the performance shares will vary according to the number of shares of common stock that are ultimately granted based upon the actual level of attainment of the performance criteria.

These performance share awards were paid 50% in cash and 50% in common stock.

The outstanding performance periods at December 31, 2023 were as follows:

			Possible Payout Range of Target	
Grant Date	Performance Period	Target Grant of Shares	Minimum	Maximum
January 1, 2020	January 1, 2020 - December 31, 2022	35,571	0%	200%

A summary of the status of the Performance Share Plan at December 31, 2023 was as follows:

	Equity Portion		Liability Portion	
	Shares	Weighted-Average Grant Date Fair Value [(a)]	Shares	Weighted-Average Fair Value at December 31, 2023
Performance Shares balance at beginning of period	18,105	$ 81.42	18,105	
Granted	—	—	—	
Forfeited	—	—	—	
Vested	(18,105)	81.42	(18,105)	
Performance Shares balance at end of period	—	$ —	—	$ —

(a) The grant date fair values for the performance shares granted in 2020 were determined by Monte Carlo simulation using a blended volatility of 18%, comprised of 50% historical volatility and 50% implied volatility and the average risk-free interest rate of the three-year United States Treasury security rate in effect as of the grant date.

Performance plan payouts have been as follows (in millions, except stock issued):

Performance Period	Year Paid	Stock Issued	Cash Paid	Total Intrinsic Value
January 1, 2020 to December 31, 2022	2023	4,958	$ 0.3	$ 0.7
January 1, 2019 to December 31, 2021	2022	7,582	$ 0.5	$ 1.0
January 1, 2018 to December 31, 2020	2021	27,515	$ 1.6	$ 3.3

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(15) INCOME TAXES

IRS Revenue Procedure 2023-15

On April 14, 2023, the IRS released Revenue Procedure 2023-15 "Amounts paid to improve tangible property." The Revenue Procedure provides a safe harbor method of accounting that taxpayers may use to determine whether costs to repair, maintain, replace, or improve natural gas transmission and distribution property must be capitalized. The revenue procedure may be adopted in tax years ending after May 1, 2023. We are currently assessing the Revenue Procedure to determine its impact on our tax repairs deduction.

Income Tax Expense (Benefit)

Income tax expense (benefit) from continuing operations for the years ended December 31 was (in millions):

	2023	2022	2021
Current:			
Federal	$ (0.8)	$ (0.5)	$ 0.6
State	1.0	0.1	(0.7)
Current income tax (benefit)	0.2	(0.4)	(0.1)
Deferred:			
Federal	30.9	23.2	2.2
State	(5.5)	2.4	5.1
Deferred income tax expense	25.4	25.6	7.3
Income tax expense	$ 25.6	$ 25.2	$ 7.2

Effective Tax Rates

The effective tax rate differs from the federal statutory rate for the years ended December 31, as follows:

	2023	2022	2021
Federal statutory rate	21.0 %	21.0 %	21.0 %
State income tax (net of federal tax effect) [a]	(0.8)	0.5	1.2
Non-controlling interest [b]	(1.0)	(0.9)	(1.2)
Tax credits	(6.2)	(7.7)	(8.4)
Flow-through adjustments [c]	(1.7)	(1.4)	(3.2)
Amortization of excess deferred income taxes [d]	(3.0)	(2.5)	(3.1)
TCJA bill credits [e]	—	(0.4)	(3.6)
Other	0.2	(0.1)	0.1
Effective Tax Rate	8.5 %	8.5 %	2.8 %

(a) The state effective tax rate contains the tax expense attributable to multiple statutory state rate changes in the Company's state jurisdictions. For the year ended December 31, 2023, we recognized an $8.2 million tax benefit from a Nebraska income tax rate decrease.
(b) The effective tax rate reflects the income attributable to the non-controlling interest in Black Hills Colorado IPP for which a tax provision was not recorded.
(c) Flow-through adjustments related primarily to accounting method changes for tax purposes that allow us to take a current tax deduction for repair costs and certain indirect costs. We recorded a deferred income tax liability in recognition of the temporary difference created between book and tax treatment and flowed the tax benefit through to tax expense. A regulatory asset was established to reflect the recovery of future increases in taxes payable from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record tax benefits consistent with the flow-through method.
(d) Primarily TCJA - see Note 2 for additional information.
(e) Primarily related to one-time bill credits of TCJA benefits delivered to Colorado Electric and Nebraska Gas customers in 2021. These bill credits, which resulted in a reduction in revenue, were offset by a reduction in income tax expense and resulted in a minimal impact to Net income for the year ended December 31, 2021.

Deferred Tax Assets and Liabilities

The temporary differences, which gave rise to the net deferred tax liability, for the years ended December 31 were as follows (in millions):

	2023	2022
Deferred tax assets:		
Regulatory liabilities	$ 74.0	$ 74.7
State tax credits	22.8	22.8
Federal NOL	146.6	192.0
State NOL	16.5	23.0
Partnership	12.2	12.8
Credit Carryovers	110.1	90.9
Other deferred tax assets	33.7	45.4
Less: Valuation allowance	(15.4)	(15.5)
Total deferred tax assets	400.5	446.1
Deferred tax liabilities:		
Accelerated depreciation, amortization and other property-related differences	(686.2)	(645.7)
Regulatory assets	(65.6)	(94.4)
Goodwill	(67.8)	(57.9)
State deferred tax liability	(84.5)	(98.2)
Other deferred tax liabilities	(44.4)	(58.8)
Total deferred tax liabilities	(948.5)	(955.0)
Net deferred tax liability	$ (548.0)	$ (508.9)

Net Operating Loss and Tax Credit Carryforwards

At December 31, 2023, we have federal NOL and state NOL and tax credit carryforwards that will expire at various dates as follows (in millions):

	Amounts	Expiration Dates
Federal NOL Carryforward	$ 111.0	2036-2037
Federal NOL Carryforward	$ 587.3	No expiration
Federal Tax Credit Carryforward	$ 110.1	2028-2043
State NOL Carryforward [(a)]	$ 325.3	2024-2042
State Tax Credit Carryforward	$ 22.8	2024-2038

(a) The carryforward balance is reflected on the basis of apportioned tax losses to jurisdictions imposing state income taxes.

As of December 31, 2023, we had a $1.0 million valuation allowance against the state NOL carryforwards. Our 2023 analysis of the ability to utilize such NOLs resulted in no increase in the valuation allowance. If the valuation allowance is adjusted due to higher or lower than anticipated utilization of the NOLs, the offsetting amount will affect tax expense.

As of December 31, 2023, we had a $14.4 million valuation allowance against the state ITC carryforwards. Our 2023 analysis of the ability to utilize such ITC resulted in a slight decrease in the valuation allowance.

Unrecognized Tax Benefits

The following table reconciles the total amounts of unrecognized tax benefits, without interest, at the beginning and end of the period included in Other deferred credits and other liabilities on the accompanying Consolidated Balance Sheets (in millions):

Changes in Uncertain Tax Positions:	2023	2022	2021
Beginning balance	$ 11.9	$ 10.6	$ 8.4
Additions for prior year tax positions	—	—	0.5
Reductions for prior year tax positions	(0.3)	(0.8)	(0.7)
Additions for current year tax positions	2.1	2.1	2.4
Ending balance	$ 13.7	$ 11.9	$ 10.6

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $6.5 million.

We recognized no interest expense associated with income taxes for the years ended December 31, 2023, 2022 and 2021. We had no accrued interest (before tax effect) associated with income taxes at December 31, 2023 and 2022.

As of December 31, 2023, we do not have any tax positions for which it is reasonably possible that the total amount of unrecognized tax benefits will significantly increase or decrease on or before December 31, 2024.

We are subject to federal income tax as well as income tax in various state and local jurisdictions. As of December 31, 2023, tax years for 2020, 2021, and 2022 are subject to examination by the tax authorities. With few exceptions, we are no longer subject to U.S. or state exam for years before 2020. Tax years 2017 and 2018 was open as of December 31, 2023.

(16) BUSINESS SEGMENT INFORMATION

Our Chief Executive Officer, who is considered to be our CODM, reviews financial information presented on an operating segment basis for purposes of making decisions, allocating resources and assessing financial performance. Our operating segments are based on our method of internal reporting, which is generally segregated by differences in products and services. All of our operations and assets are located within the United States.

Our Electric Utilities segment includes the operating results of the regulated electric utility operations of Colorado Electric, South Dakota Electric, and Wyoming Electric, which supply regulated electric utility services to areas in Colorado, Montana, South Dakota and Wyoming. We also own and operate non-regulated power generation and mining businesses that are vertically integrated with our Electric Utilities.

Our Gas Utilities segment consists of the operating results of our regulated natural gas utility subsidiaries in Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming.

Corporate and Other represents certain unallocated expenses for administrative activities that support our operating segments. Corporate and Other also includes business development activities that are not part of our operating segments and inter-segment eliminations.

Our CODM assesses the performance of our operating segments based on operating income. Our CODM reviews capital expenditures by operating segment rather than any individual or total asset amount. Our operating segments are equivalent to our reportable segments.

Segment information was as follows (in millions):

	Consolidating Income Statement			
Year ended December 31, 2023	**Electric Utilities**	**Gas Utilities**	**Corporate and Other**	**Total**
Revenue -				
External Customers	$ 853.6	$ 1,477.7	$ —	$ 2,331.3
Inter-segment	11.4	6.5	(17.9)	—
Total revenue	865.0	1,484.2	(17.9)	2,331.3
Fuel, purchased power and cost of natural gas sold	200.1	783.2	(0.4)	982.9
Operations and maintenance	236.2	328.7	(12.9)	552.0
Depreciation, depletion and amortization	142.6	113.9	0.3	256.8
Taxes - property and production	37.3	29.6	—	66.9
Operating income (loss)	$ 248.8	$ 228.8	$ (4.9)	$ 472.7
Interest expense, net				(167.9)
Other income (expense), net				(3.2)
Income tax (expense)				(25.6)
Net income				276.0
Net income attributable to non-controlling interest				(13.8)
Net income available for common stock				$ 262.2

Year ended December 31, 2022	Consolidating Income Statement Electric Utilities	Gas Utilities	Corporate and Other	Total
Revenue -				
External Customers	$ 888.4	$ 1,663.4	$ —	$ 2,551.8
Inter-segment	11.8	5.7	(17.5)	—
Total revenue	900.2	1,669.1	(17.5)	2,551.8
Fuel, purchased power and cost of natural gas sold	266.3	965.1	(0.8)	1,230.6
Operations and maintenance	244.8	317.3	(13.7)	548.4
Depreciation, depletion and amortization	135.9	114.7	0.3	250.9
Taxes - property and production	38.9	27.8	—	66.7
Operating income (loss)	$ 214.3	$ 244.2	$ (3.3)	$ 455.2
Interest expense, net				(161.0)
Other income (expense), net				1.8
Income tax (expense)				(25.2)
Net income				270.8
Net income attributable to non-controlling interest				(12.4)
Net income available for common stock				$ 258.4

Year ended December 31, 2021	Consolidating Income Statement Electric Utilities	Gas Utilities	Corporate and Other	Total
Revenue -				
External Customers	$ 830.7	$ 1,118.4	$ —	$ 1,949.1
Inter-segment	11.5	6.5	(18.0)	—
Total revenue	842.2	1,124.9	(18.0)	1,949.1
Fuel, purchased power and cost of natural gas sold	248.0	494.7	(0.8)	741.9
Operations and maintenance	224.5	290.2	(13.0)	501.7
Depreciation, depletion and amortization	131.5	104.2	0.3	236.0
Taxes - property and production	35.5	24.6	—	60.1
Operating income (loss)	$ 202.7	$ 211.2	$ (4.5)	$ 409.4
Interest expense, net				(152.4)
Other income (expense), net				1.4
Income tax (expense)				(7.2)
Net income				251.2
Net income attributable to non-controlling interest				(14.5)
Net income available for common stock				$ 236.7

Capital Expenditures [(a)] for the years ended December 31,	2023	2022	2021
Electric Utilities	$ 210.7	$ 243.1	$ 285.8
Gas Utilities	371.9	349.5	383.3
Corporate and Other	7.3	5.1	10.5
Total capital expenditures	$ 589.9	$ 597.7	$ 679.6

(a) Includes accruals for property, plant and equipment as disclosed in the Supplemental Cash Flow Information to the Consolidated Statement of Cash Flows.

(17) SUBSEQUENT EVENTS

Except as described in Note 2, there have been no events subsequent to December 31, 2023 which would require recognition in the Consolidated Financial Statements or disclosures.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 (Exchange Act)) as of December 31, 2023. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective.

Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act, as amended, is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the quarter ended December 31, 2023, there were no changes in the Company's internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting is presented on Page 56 of this Annual Report on Form 10-K.

ITEM 9B. OTHER INFORMATION

None of our directors or officers adopted, modified, or terminated a Rule 10b5-1 trading arrangement or a non-Rule 10b5-1 trading arrangement during the three months ended December 31, 2023.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information required under this item with respect to directors and information required by Items 401, 405, 406, 407(c)(3), 407(d)(4), 407(d)(5) and 408(b) of Regulation S-K, is set forth in the Proxy Statement for our 2024 Annual Meeting of Shareholders, which is incorporated herein by reference. Information about our Executive Officers is reported in Part 1 of this Annual Report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

Information required under this item is set forth in the Proxy Statement for our 2024 Annual Meeting of Shareholders, which is incorporated herein by reference.

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ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information regarding the security ownership of certain beneficial owners and management is set forth in the Proxy Statement for our 2024 Annual Meeting of Shareholders, which is incorporated herein by reference.

EQUITY COMPENSATION PLAN INFORMATION

The following table includes information as of December 31, 2023 with respect to our equity compensation plans which includes the Amended and Restated 2015 Omnibus Incentive Plan.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	$ 290,266 [1]	$ — [1]	$ 2,132,275 [2]
Equity compensation plans not approved by security holders	—	—	—
Total	$ 290,266	$ —	$ 2,132,275

(1) 290,266 full value awards outstanding as of December 31, 2023, comprised of restricted stock units, performance shares, short-term incentive plan (STIP) units and Director common stock units. In addition, 148,163 shares of unvested restricted stock were outstanding as of December 31, 2023, which are not included in the table above because they have already been issued. We do not have any outstanding options, warrants or rights.

(2) Shares available for issuance are from the 2015 Amended and Restated Omnibus Incentive Plan. The 2015 Amended and Restated Omnibus Incentive Plan permits grant of stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards and other stock-based awards.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information regarding certain relationships and related transactions and director independence is set forth in the Proxy Statement for our 2024 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information regarding principal accounting fees and services billed to us by our principal accountant, Deloitte & Touche LLP (PCAOB ID No. 34) is set forth in the Proxy Statement for our 2024 Annual Meeting to Shareholders, which is incorporated herein by reference.

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PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) Documents filed as part of this report

1. Consolidated Financial Statements

Financial statements required under this item are included in Item 8 of Part II

2. Schedules

All other schedules have been omitted because of the absence of the conditions under which they are required or because the required information is included in our consolidated financial statements and notes thereto. Consolidated valuation and qualifying accounts are detailed within Note 1 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

3. Exhibits

Exhibits filed herewithin are designated by an asterisk (*). All exhibits not so designated are incorporated by reference to a prior filing, as indicated. Items constituting a board of director or management compensatory plan are designated by a cross (†).

Exhibit Number	Description
2.1	Purchase and Sale Agreement by and among Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, as Sellers, and Black Hills Utility Holdings, Inc., as Buyer, dated as of July 12, 2015 (filed as Exhibit 2.1 to the Registrant's Form 8-K filed on July 14, 2015).
2.2	First Amendment to Purchase and Sale Agreement effective December 10, 2015, by and among, Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, as Sellers, and Black Hills Utility Holdings, Inc., as Buyer (filed as Exhibit 2.2 to the Registrant's Form 10-K for 2015).
2.3	Option Agreement, by and among, Aircraft Services Corporation, as ASC, SourceGas Holdings LLC, as the Company and Black Hills Utility Holdings, Inc., as Buyer (filed as Exhibit 2.2 to the Registrant's Form 8-K filed on July 14, 2015).
3.1	Restated Articles of Incorporation of the Registrant (filed as Exhibit 3 to the Registrant's Form 8-K filed on February 5, 2018).
3.2	Amended and Restated Bylaws of the Registrant dated April 24, 2023 (filed as Exhibit 3.2 to the Registrant's Form 8-K filed on May 3, 2023).
4.1	Indenture dated as of May 21, 2003 between the Registrant and Wells Fargo Bank, National Association (as successor to LaSalle Bank National Association), as Trustee (filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003).
4.1-1	First Supplemental Indenture dated as of May 21, 2003 (filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003).
4.1-2	Second Supplemental Indenture dated as of May 14, 2009 (filed as Exhibit 4 to the Registrant's Form 8-K filed on May 14, 2009).
4.1-3	Third Supplemental Indenture dated as of July 16, 2010 (filed as Exhibit 4 to Registrant's Form 8-K filed on July 15, 2010).
4.1-4	Fourth Supplemental Indenture dated as of November 19, 2013 (filed as Exhibit 4 to the Registrant's Form 8-K filed on November 18, 2013).
4.1-5	Fifth Supplemental Indenture dated as of January 13, 2016 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on January 13, 2016).
4.1-6	Sixth Supplemental Indenture dated as of August 19, 2016 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on August 19, 2016).
4.1-7	Seventh Supplemental Indenture dated as of August 17, 2018 (filed as Exhibit 4.2 to the Registrant's Form 8-K filed on August 17, 2018).
4.1-8	Eighth Supplemental Indenture dated as of October 3, 2019 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on October 4, 2019).

4.1-9	Ninth Supplemental Indenture dated as of June 17, 2020 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on June 17, 2020).
4.1-10	Tenth Supplemental Indenture dated as of August 26, 2021 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on August 26, 2021).
4.1-11	Eleventh Supplemental Indenture dated as of March 7, 2023 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on March 7, 2023).
4.1-12	Twelfth Supplemental Indenture dated as of September 15, 2023 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on September 15, 2023).
4.2	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as Exhibit 4.19 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)).
4.2-1	First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)).
4.2-2	Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant's Post-Effective Amendment No. 2 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)).
4.2-3	Third Supplemental Indenture, dated as of October 1, 2014, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on October 2, 2014).
4.3	Restated Indenture of Mortgage, Deed of Trust, Security Agreement and Financing Statement, amended and restated as of November 20, 2007, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on October 2, 2014).
4.3-1	First Supplemental Indenture, dated as of September 3, 2009, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on October 2, 2014).
4.3-2	Second Supplemental Indenture, dated as of October 1, 2014, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.4 to the Registrant's Form 8-K filed on October 2, 2014).
4.4	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000).
4.5	Description of Securities (filed as Exhibit 4.5 to the Registrant's Form 10-K for 2019)
10.1†	Amended and Restated Pension Equalization Plan of Black Hills Corporation dated November 6, 2001 (filed as Exhibit 10.11 to the Registrant's Form 10-K/A for 2001).
10.1-1†	First Amendment to Pension Equalization Plan (filed as Exhibit 10.10 to the Registrant's Form 10-K for 2002).
10.1-2†	Grandfather Amendment to the Amended and Restated Pension Equalization Plan of Black Hills Corporation (filed as Exhibit 10.2 to the Registrant's Form 10-K for 2008).
10.2†	Restoration Plan of Black Hills Corporation (filed as Exhibit 10.5 to the Registrant's Form 10-K for 2008).
10.2-1†	First Amendment to the Restoration Plan of Black Hills Corporation dated July 24, 2011 (filed as Exhibit 10.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2011).
10.3†	Black Hills Corporation Non-qualified Deferred Compensation Plan as Amended and Restated effective January 1, 2011 (filed as Exhibit 10.4 to the Registrant's Form 10-K for 2010).
10.3-1†	First Amendment to the Black Hills Corporation Nonqualified Deferred Compensation Plan as Amended and Restated effective January 1, 2011 (filed as Exhibit 10.5 to the Registrant's Form 10-K for 2018).
10.4†	Black Hills Corporation Post-2018 Nonqualified Deferred Compensation Plan (filed as Exhibit 10.4 to the Registrant's Form 10-K for 2022).
10.5†	Black Hills Corporation 2005 Omnibus Incentive Plan ("Omnibus Plan") (filed as Appendix A to the Registrant's Proxy Statement filed April 13, 2005).
10.5-1†	First Amendment to the Omnibus Plan (filed as Exhibit 10.11 to the Registrant's Form 10-K for 2008).
10.5-2†	Second Amendment to the Omnibus Plan (filed as Exhibit 10 to the Registrant's Form 8-K filed on May 26, 2010).
10.6†	Black Hills Corporation Amended and Restated 2015 Omnibus Incentive Plan effective January 24, 2023 (filed as Exhibit 10.6 to the Registrant's Form 10-K for 2022).

10.7†	Form of Stock Option Agreement for Omnibus Plan effective for awards granted on or after January 1, 2014 (filed as Exhibit 10.7 to the Registrant's Form 10-K for 2013).
10.8†	Form of Stock Option Agreement effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.8 to Registrant's Form 10-K for 2015).
10.9†	Form of Restricted Stock Award Agreement for 2015 Omnibus Incentive Plan effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.10 to Registrant's Form 10-K for 2015).
10.10†	Form of Restricted Stock Award Agreement for 2015 Omnibus Incentive Plan effective for awards granted on or after January 26, 2021. (filed as Exhibit 10.11 to the Registrant's Form 10-K for 2020)
10.11†	Form of Restricted Stock Unit Award Agreement for 2015 Omnibus Plan effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.12 to the Registrant's Form 10-K for 2015).
10.12†	Form of Performance Share Award Agreement effective for awards granted on or after January 1, 2016 (filed as Exhibit 10.6 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2016).
10.13†	Form of Performance Share Award Agreement effective for awards granted on or after January 1, 2017 (filed as Exhibit 10.12 to the Registrant's Form 10-K for 2019).
10.14†	Form of Short-term Incentive Plan for Officers Award Agreement effective for awards granted on or after January 1, 2021 (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2020).
10.15†	Form of Performance Unit Award Agreement for 2015 Omnibus Incentive Plan effective for awards granted on or after January 1, 2021. (filed as Exhibit 10.17 to the Registrant's Form 10-K for 2020)
10.16†	Form of Indemnification Agreement (filed as Exhibit 10.5 to the Registrant's Form 8-K filed on September 3, 2004).
10.17†	Change in Control Agreement dated November 15, 2022 between Black Hills Corporation and Linden R. Evans.
10.18†	Change in Control Agreements dated November 15, 2022 between Black Hills Corporation and its non-CEO Senior Executive Officers.
10.19†	Outside Directors Stock Based Compensation Plan as Amended and Restated effective January 1, 2009 (filed as Exhibit 10.23 to the Registrant's Form 10-K for 2008).
10.19-1†	First Amendment to the Outside Directors Stock Based Compensation Plan effective January 1, 2011 (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2010).
10.19-2†	Second Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2013 (filed as Exhibit 10.15 to the Registrant's Form 10-K for 2012).
10.19-3†	Third Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2015 (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2014).
10.19-4†	Fourth Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2017 (filed as Exhibit 10.4 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2016).
10.19-5†	Fifth Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2018 (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2017).
10.19-6†	Sixth Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2019 (filed as Exhibit 10.18 to the Registrant's Form 10-K for 2018).
10.20†	Form of Non-Disclosure and Non-Solicitation Agreement for Certain Employees (filed as Exhibit 10.8 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2016).
10.21	Equity Distribution Sales Agreement dated June 16, 2023 among Black Hills Corporation and the several Agents named therein (filed as Exhibit 1.1 to the Registrant's Form 8-K filed on June 20, 2023).
10.22	Fourth Amended and Restated Credit Agreement dated as of July 19, 2021 (relating to $750 million Revolving Credit Facility), among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and U.S. Bank, National Association, as Administrative Agent (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on July 19, 2021).
10.22-1	First Amendment to Fourth Amended and Restated Credit Agreement dated as of May 9, 2023 (relating to $750 million Revolving Credit Facility), among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and U.S. Bank, National Association, as Administrative Agent (filed as Exhibit 10.1 to the Registrant's Form 10-Q filed on August 3, 2023).
10.23†	Letter Agreement between Black Hills Corporation and Jennifer C. Landis (filed as Exhibit 10.1 to Form 10-Q filed May 4, 2023).
10.24†	Non-Employee Director Equity Compensation Plan effective January 1, 2022 (filed as Exhibit 10.25 to the Registrant's Form 10-K filed on February 15, 2022).

10.25†	Form of Restricted Stock Unit Award Agreement (Non-Employee Director) effective for awards granted on or after January 1, 2022 (filed as Exhibit 10.26 to the Registrant's Form 10-K filed on February 15, 2022).
10.26	Coal Leases between WRDC and the Federal Government -Dated May 1, 1959 (filed as Exhibit 5(i) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(h) to the Registrant's Form 10-K for 1989) -Dated April 1, 1961 (filed as Exhibit 5(j) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(i) to Registrant's Form 10-K for 1989) -Dated October 1, 1965 (filed as Exhibit 5(k) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(j) to the Registrant's Form 10-K for 1989).
10.27	Assignment of Mining Leases and Related Agreement effective May 27, 1997, between WRDC and Kerr-McGee Coal Corporation (filed as Exhibit 10(u) to the Registrant's Form 10-K for 1997).
10.28†	Form of Restricted Stock Award Agreement for the Amended and Restated 2015 Omnibus Incentive Plan effective for awards granted on or after January 24, 2023 (filed as Exhibit 10.30 to the Registrant's Form 10-K for 2022).
10.29†	Form of Performance Unit Award Agreement for the Amended and Restated 2015 Omnibus Incentive Plan effective for awards granted on or after January 1, 2023 (filed as Exhibit 10.29 to the Registrant's Form 10-K for 2022).
10.30*†	Form of Short-term Incentive Plan Award Agreement for the Amended and Restated 2015 Omnibus Incentive Plan effective for awards granted on or after January 1, 2024.
10.31*†	Form of Performance Unit Award Agreement for the Amended and Restated 2015 Omnibus Incentive Plan effective for awards granted on or after January 1, 2024.
19*	Insider Trading Policy
21*	List of Subsidiaries of Black Hills Corporation.
23.1*	Consent of Independent Registered Public Accounting Firm.
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
32.1*	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95*	Mine Safety and Health Administration Safety Data
97*†	Mandatory Compensation Recovery Policy dated December 1, 2023
101.INS*	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document
101.SCH*	Inline XBRL Taxonomy Extension Schema with Embedded Linkbases Document
104*	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BLACK HILLS CORPORATION

By: /S/ LINDEN R. EVANS

Linden R. Evans, President and Chief Executive Officer

Dated: February 14, 2024

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

/S/ STEVEN R. MILLS Steven R. Mills	Director and Chairman	February 14, 2024
/S/ LINDEN R. EVANS Linden R. Evans, President and Chief Executive Officer	Director and Principal Executive Officer	February 14, 2024
/S/ KIMBERLY F. NOONEY Kimberly F. Nooney, Senior Vice President and Chief Financial Officer	Principal Financial and Accounting Officer	February 14, 2024
/S/ BARRY M. GRANGER Barry M. Granger	Director	February 14, 2024
/S/ TONY A. JENSEN Tony A. Jensen	Director	February 14, 2024
/S/ KATHLEEN S. MCALLISTER Kathleen S. McAllister	Director	February 14, 2024
/S/ ROBERT P. OTTO Robert P. Otto	Director	February 14, 2024
/S/ SCOTT M. PROCHAZKA Scott M. Prochazka	Director	February 14, 2024
/S/ REBECCA B. ROBERTS Rebecca B. Roberts	Director	February 14, 2024
/S/ MARK A. SCHOBER Mark A. Schober	Director	February 14, 2024
/S/ TERESA A. TAYLOR Teresa A. Taylor	Director	February 14, 2024

Black Hills Corporation
Short-Term Incentive Plan
Award Agreement
(Effective for Plan Years Beginning on or after January 1, 2024)

You have been selected to be a Participant in the Black Hills Corporation Short-Term Incentive Plan (the "STIP"). The STIP is granted under the cash-based awards provisions of the Black Hills Corporation Amended and Restated 2015 Omnibus Incentive Plan (the "Plan"). This Agreement and the Plan together govern your rights to the Award and set forth all of the conditions and limitations affecting such rights. All capitalized terms shall have the meanings ascribed to them in the Plan unless specifically set forth otherwise herein. If there is any inconsistency between the terms of this Agreement and the terms of the Plan, the Plan's terms shall supersede and replace the conflicting terms of this Agreement.

Overview of Your Award

Participant: Name: ______________________

Target STIP Award: X (XX) percent of Eligible Earnings

Performance Period: January 1, 2024 to December 31, 2024

Performance Measure:

Category	Weight		2024 Metrics
Financial	70%		EPS
Safety Index	7.5%	2.5%	Timeliness of Incident Reporting
		2.5%	Average Safety Events/Employee
		2.5%	Days Away, Restricted, or Transferred (DART)
System Safety & Reliability	7.5%	3.75%	Hits per Thousand (HPT)
		3.75%	System Average Interruption Duration Index (SAIDI)
Customer Experience Index	7.5%	3.75%	Customer Satisfaction
		3.75%	Customer Effort
Diversity Index	7.5%		% Prof/Tech Positions with 2 or more Diverse Candidates

Article 1. Effective Date and Purpose of Plan

The Performance Period commences on January 1, 2024 and ends on December 31, 2024.

Article 2. Definitions

Unless the context otherwise specifically requires, the following words as used herein shall have the following meanings:

Eligible Earnings means the Participant's regular compensation such as base salary and lump sum in lieu of merit increase. Eligible Earnings exclude, but are not limited to, non-cash compensation, payments-in-kind, incentive compensation, bonus payments, allowances, and deferred compensation.

Board means the Board of Directors of the Company.

Committee means the Compensation Committee of the Board.

Company means Black Hills Corporation, a South Dakota corporation with principal offices in the state of South Dakota.

Employee means any person who is in the regular full-time employment of the Company or a Subsidiary, as determined by the personnel rules and practices of the Company or a Subsidiary. The term does not include persons who are retained by the Company or a Subsidiary solely as consultants.

Incentive Award means the incentive compensation to be awarded to a Participant as determined under Article 5.

Participants means those eligible Employees to whom an Incentive Award is granted.

Performance Period means the period of time selected by the Committee over which the attainment of one or more performance goals will be measured.

Plan means the 2015 Amended and Restated Omnibus Incentive Plan.

Plan Year means the 12 months beginning on January 1 and ending on the following December 31.

Retirement or **Retires** means a Separation from Service by a Participant on or after (i) attaining the age of 55 with at least 5 years of service, or (ii) attaining the age of 65.

Separation of Service (as defined in Treasury Regulation Section 1.409A-1(h)) during the Performance Period other than (i) due to Retirement, disability or death, or (ii) following a change in control shall require forfeiture of this entire award, with no payment to the Participant.

Subsidiary shall mean any business organization in which Company, directly or indirectly, owns a majority of its voting power or voting equity securities or equity interest.

Article 3. Eligibility and Participants

Employees eligible to participate under this Agreement will be designated by the Committee.

Article 4. Administration of the Plan

This Agreement and the rights of the Participant hereunder are subject to all the terms and conditions of the Plan, as the same may be amended, modified, suspended or terminated from time to time by the Committee, as well as to such rules and regulations as the Committee may adopt for administration of the Plan. It is expressly understood that the Committee is authorized to administer, construe, and make all determinations necessary or appropriate to the administration of the Plan and this Agreement, in its sole discretion, all of which shall be binding upon the Participant.

Any inconsistency between the Agreement and the Plan shall be resolved in favor of the Plan.

Article 5. Target Incentive Award and Performance Measures

Participant was assigned a target Incentive Award determined as a percent of a Participant's Eligible Earnings. Participant shall have the opportunity to earn various percentages of the target Incentive Award. The percentage of the target Incentive Award to be earned by the Participant shall be determined by the application of objective performance measurements determined by the Committee, such as earnings per share. The application of the Participant's target Incentive Award to actual performance results creates the actual award for each Participant ("Incentive Award").

If Participant has a change during the Plan Year that impacts their target Incentive Award, determination of the target Incentive Award and performance measures are based on the target Incentive Award and performance measures in place for the Employee as of September 30 or their termination date for eligible Participants as described in Article 6.

Article 6. Termination Provisions

Except as provided below in this Article 6 and in Article 7, a Participant shall be eligible for payment of the Incentive Award, as determined in Article 5, only if the Participant’s employment with the Company or a Subsidiary continues through the last working day of the Performance Period.

If Participant Retires, suffers a disability, or dies during the Performance Period, the Participant (or the Participant’s estate) shall be entitled to that proportion of the Incentive Award as such Participant is entitled to under Article 5 for such Performance Period. The form and timing of the payment of such Performance Shares shall be as set forth in Article 9.

Article 7. Change in Control

Notwithstanding anything herein to the contrary, in the event of a Change in Control, the Participant shall be entitled to that proportionate target Incentive Award as such Participant is entitled to under Article 5 for such Performance Period (as of the effective date of the Change in Control).

Article 8. Forfeiture and Repayment.

(a) In the event the Participant incurs a separation from service for a reason other than those described in Article 6 herein during the Performance Period this entire award will be forfeited.

(b) Without limiting the generality of Article 8(a), the Committee reserves the right to cancel the Incentive Award awarded hereunder, whether or not earned, and require the Participant to repay all income or gains previously realized in respect of such Incentive Award, in the event of the occurrence of any of the following events:

(i) termination of Participant's employment for Cause;

(ii) within one year following any termination of Participant's employment, the Committee determines that the Participant engaged in conduct before the Participant's termination date that would have constituted the basis for a termination of employment for Cause;

(iii) at any time during the Participant's employment or the twelve-month period immediately following any termination of employment, Participant:

(x) publicly disparages the Company, any of its Affiliates or any of its or their officers, directors or senior executive employees or otherwise makes any public statement that is materially detrimental to the interests or reputation of the Company, any of its Affiliates or such individuals; or

(y) violates in any material respect any policy or any code of ethics or standard of behavior or conduct generally applicable to Participant, including the Code of Conduct (defined to include any code of ethics or code of conduct now or hereafter adopted by the Company or any of its Affiliates, including to the extent applicable the Code of Business Conduct, as amended or supplemented from time to time, and the Company's or subsidiary Risk Management Policies, as amended, supplemented or replaced from time to time); or

(iv) Participant engages in any fraudulent, illegal or other misconduct involving the Company or any of its Affiliates, including but not limited to any breach of fiduciary duty, breach of a duty of loyalty, or interference with contract or business expectancy.

(c) If the Committee determines that the Participant's conduct, activities or circumstances constitute events described in Article 8(b), in addition to any other remedies the Company has available to it, the Committee may in its sole discretion:

(i) cancel any Incentive Award, whether or not issued; and/or

(ii) require the Participant to repay an amount equal to all income or gain realized in respect of all such Incentive Award.

There shall be no forfeiture or repayment under Article 8(b) following a Change in Control.

(d) The Committee, in its discretion, shall determine whether a Participant's conduct, activities or circumstances constitute events described in Article 8(b) and whether and to what extent the Incentive Award shall be forfeited by Participant and/or a Participant shall be required to repay an amount pursuant to Article 8(c). The Committee shall have the authority to suspend the payment, delivery or settlement of all or any portion of such Participant's outstanding Incentive Award pending an investigation of a bona fide dispute regarding Participant's eligibility to receive a payment under the terms of this Agreement as determined by the Committee in good faith.

(e) Participant agrees that the provisions of this Article 8 are entered into in consideration of, and as a material inducement to, the agreements herein as well as an inducement for the Company to enter into this Agreement, and that, but for Participant's agreement to the provisions of this Article 8, the Company would not have entered into this Agreement.

The Incentive Award is also subject to the provisions on forfeiture events and clawbacks set forth in Article 21 of the Plan.

Article 9. Payment of Incentive Award

The Incentive Award shall be paid to the Participant in the form of cash after required tax and applicable deductions are withheld.

Article 10. Assignability

No right to receive payments under this Agreement shall be subject to voluntary or involuntary alienation, assignment or transfer.

Article 11. Right to Incentive Award

The Committee determines the amount of the Incentive Award for the senior executive officers, and management determines the amount of the award for other participants, which determinations are to be made in January of each Plan Year based on the application of the target incentives and performance measures to the preceding year and no Participant shall be considered to have earned any portion of any Incentive Award until determination by the Committee. Notwithstanding anything contained herein, no Participant shall have any right to receive any Incentive Award unless he/she is an Employee of the Company through the last working day of each Plan Year. In the event of a Change in Control, a Participant's Incentive Award shall be determined as of the date of the Change in Control and shall be paid 30 days after the day of the Change in Control.

Article 12. Miscellaneous

(a) The selection of any employee for participation in the Plan shall not give such Participant any right to be retained in the employ of the Company. The right and power of the Company to dismiss or discharge any Participant at-will, is specifically reserved. Such Participant or any person claiming under or through the Participant shall not have any right or interest in the Plan or any Award thereunder, unless and until all terms, conditions, and provisions of the Plan that affect such Participant have been complied with as specified herein.

(b) With the approval of the Board, the Committee may terminate, amend, or modify the Plan; provided, however, that no such termination, amendment, or modification of the Plan may in any way adversely affect the Participant's rights under this Agreement without the Participant's written consent, except as required by law.

(c) This Agreement shall be subject to all applicable laws, rules, and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required.

(d) To the extent not preempted by federal law, this Agreement shall be governed by, and construed in accordance with, the laws of the State of South Dakota.

(e) Waiver and Modification. The provisions of this Agreement may not be waived or modified unless such waiver or modification is in writing and signed by the Company.

(f) Severability. In the event any provision of this Agreement shall be held to be illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining parts of this Agreement, and the Agreement shall be construed and enforced as if the illegal or invalid provision had not been included.

Article 13. No Tax Qualified or ERISA Plan

This is not intended to be a tax qualified Plan nor a Plan for the purposes of ERISA.

Black Hills Corporation Participant

________________________________ ________________________________

Amy K. Koenig
Vice President – Governance, Corporate Secretary
and Deputy General Counsel

Black Hills Corporation
Long-Term Incentive Plan
Performance Unit Award Agreement
Performance Period **-** January 1, 2024 – December 31, 2026

You have been selected to be a Participant in the Black Hills Corporation Long-Term Incentive Plan (the "LTIP"). This LTIP award is granted under the performance units and performance shares provisions of the Amended and Restated 2015 Omnibus Incentive Plan (the "Plan"). This Agreement and the Plan together govern your rights to the Award and set forth all of the conditions and limitations affecting such rights. All capitalized terms shall have the meanings ascribed to them in the Plan unless specifically set forth otherwise herein. If there is any inconsistency between the terms of this Agreement and the terms of the Plan, the Plan's terms shall supersede and replace the conflicting terms of this Agreement.

Overview of Your Award

Participant: Name: ____________________

Target Number of Performance Units: ____________________________

Performance Period: January 1, 2024 to December 31, 2026

Performance Measures: See Appendix A

Article 1. Performance Period

The Performance Period commences on January 1, 2024 and ends on December 31, 2026.

Article 2. Award of Performance Units

Subject to the terms and conditions of this Agreement, the Company grants to the Participant a Performance Unit Award consisting of the Target Number of Performance Units set forth above, with the actual number of Performance Units earned depending on the degree to which the Company satisfies the Performance Goals specified in Appendix A to this Agreement during the Performance Period. Each Performance Unit that vests in accordance with Article 3 represents the right to receive one Share. The Performance Units granted under this Agreement (the "Units") will be credited to an account in the Participant's name maintained by the Company. This account shall be unfunded and maintained for bookkeeping purposes only, with each Unit representing an unfunded and unsecured promise by the Company to issue to the Participant one Share in settlement of a vested Unit.

Article 3. Scheduled Vesting of Performance Units

For purposes of this Agreement, “Vesting Date” means any date, including the Scheduled Vesting Date (defined below), on which Units vest as provided in this Article 3 or in Article 4 or 5. For these purposes, the “Scheduled Vesting Date” means the date the Committee certifies the degree to which the applicable Performance Goals for the Performance Period have been satisfied, provided that such certification shall occur no later than February 1 of the calendar year immediately following the calendar year during which the Performance Period ended. The Units will vest on the Scheduled Vesting Date (i) if the Participant has not experienced a Separation from Service on or before the Scheduled Vesting Date, and (ii) only to the extent that the Units have been earned as provided below.

Article 4. Termination Provisions

If the Participant Retires, has a Separation of Service due to Disability, or dies during the Performance Period, then a portion of the Units subject to this Award will vest as of the Scheduled Vesting Date. That portion shall be equal to the number of Units as such Participant is entitled to under Article 3 for such Performance Period multiplied by a fraction, the numerator of which is the number of full months of participation during the Performance Period and the denominator is 36.

“Retirement” or “Retires” means a Separation from Service by a Participant on or after (i) attaining the age of 55 with at least 5 years of service, or (ii) attaining the age of 65.

Separation from Service during the Performance Period other than (i) due to Retirement, Disability, or death, or (ii) following a Change in Control shall require forfeiture of this entire award, with no payment to the Participant.

Article 5. Change in Control

The provisions of Article 17 of the Plan shall govern in the event of a Change in Control.

Article 6. Earned Units

The number of Units that the Participant will be deemed to have earned (the “Earned Units”) and that are eligible for vesting as of the Scheduled Vesting Date will be determined by the extent to which the Company has satisfied the Performance Goals for the Performance Period as set forth in Appendix A to this Agreement. The portion of the Units subject to this Award that will be deemed Earned Units as of the Scheduled Vesting Date will be determined in accordance with the formula specified in Appendix A, and in no event will the number of Units that are deemed Earned Units exceed 200% of the Target Number of Performance Units. Any Units subject to this Agreement that are not earned and do not vest as of the Scheduled Vesting Date will be forfeited.

Article 7. Settlement of Units

After any Units vest pursuant to Article 3, 4 or 5, the Company will promptly, but in no event later than the next dividend payment date, cause to be issued and delivered to the Participant (or to the Participant’s estate in the event of the Participant’s death) one Share in payment and settlement of each vested Unit. Delivery of the Shares shall be effected by the delivery of a stock certificate evidencing the Shares, by an appropriate entry in the stock register maintained by the Company’s transfer agent with a notice of issuance provided to the Participant, or by the electronic delivery of the Shares to a brokerage account designated by the Participant, and shall be subject to the tax withholding provisions of Article 10 and compliance with all applicable legal requirements, including compliance with the requirements of applicable federal and state securities laws, and shall be in complete satisfaction and settlement of such vested Units. Upon settlement of the Units, the Participant will obtain, with respect to the Shares received in such settlement, full voting and other rights as a shareholder of the Company. If the Committee determines, in its sole discretion, that a Participant at any time has willfully engaged in any activity that the Committee determines was or is harmful to the Company, any unpaid or unsettled Unit will be forfeited by such Participant.

Article 8. Forfeiture and Repayment.

(a) In the event the Participant incurs a Separation from Service for a reason other than those described in Article 4 herein during the Performance Period this entire award will be forfeited, except as otherwise provided in the Plan.

(b) Without limiting the generality of Article 8(a), the Company reserves the right to cancel all Units awarded hereunder, whether or not vested, and require the Participant to forfeit any Shares issued in settlement of the Units and repay all income or gains previously realized upon sale of any such Shares in the event of the occurrence of any of the following events:

(i) termination of Participant's employment for Cause;

(ii) within one year following any termination of Participant's employment, the Committee determines that the Participant engaged in conduct before the Participant's termination date that would have constituted the basis for a termination of employment for Cause;

(iii) at any time during the Participant's employment or the twelve month period immediately following any termination of employment, Participant:

(x) publicly disparages the Company, any of its Affiliates or any of its or their officers, directors or senior executive employees or otherwise makes any public statement that is materially detrimental to the interests or reputation of the Company, any of its affiliates or such individuals; or

(y) violates in any material respect any policy or any code of ethics or standard of behavior or conduct generally applicable to Participant, including the Code of Conduct (defined to include any code of ethics or code of conduct now or hereafter adopted by the Company or any of its Affiliates, including to the extent applicable the Code of Business Conduct, as amended or supplemented from time to time, and the Company's or subsidiary Risk Management Policies, as amended, supplemented or replaced from time to time); or

(iv) Participant engages in any fraudulent, illegal or other misconduct involving the Company or any of its Affiliates, including but not limited to any breach of fiduciary duty, breach of a duty of loyalty, or interference with contract or business expectancy.

(c) If the Committee determines that the Participant's conduct, activities or circumstances constitute events described in Article 8(b), in addition to any other remedies the Company has available to it, the Company may in its sole discretion:

(i) cancel any Units awarded hereby, whether or not issued;

(ii) require the Participant to repay any Shares issued upon settlement of the Units; and/or

(iii) require the Participant to repay an amount equal to all income or gain realized in respect of all Shares issued upon settlement of the Units.

There shall be no forfeiture or repayment under Article 8(b) following a Change in Control.

(d) The Committee, in its discretion, shall determine whether a Participant's conduct, activities or circumstances constitute events described in Article 8(b) and whether and to what extent the Units awarded hereby shall be forfeited by Participant and/or a Participant shall be required to repay an amount pursuant to Article 8(c). The Committee shall have the authority to suspend the payment, delivery or settlement of all or any portion of such Participant's outstanding Units pending an investigation of a bona fide dispute regarding Participant's eligibility to receive a payment under the terms of this Agreement as determined by the Committee in good faith.

(e) Participant agrees that the provisions of this Article 8 are entered into in consideration of, and as a material inducement to, the agreements by the Company herein as well as an inducement for the Company to enter into this Agreement, and that, but for Participant's agreement to the provisions of this Article 8, the Company would not have entered into this Agreement.

The Incentive Award is also subject to the provisions on forfeiture events and clawbacks set forth in Article 21 of the Plan.

Article 9. Dividends

If, during the Performance Period, a cash dividend is declared and paid by the Company with respect to its Shares, the Participant will be credited as of the applicable dividend payment date with an additional number of Units (the "Dividend Units") equal to (i) the total cash dividend the Participant would have received if the Target Number of Performance Units credited to the Participant under this Agreement as of the related dividend payment record date (including any previously credited Dividend Units) had been actual Shares, divided by (ii) the Fair Market Value of a Share as of the applicable dividend payment date (with the quotient rounded down to the nearest whole number). If, after the Performance Period but before the Scheduled Vesting Date, a cash dividend is declared and paid by the Company with respect to its Shares, the Participant will be credited as of the applicable dividend payment date a number of Dividend Units equal to (i) the total cash dividend the Participant would have received if the Earned Units under this Agreement as of the related dividend payment record date (including any previously credited Dividend Units) had been actual Shares, divided by (ii) the Fair Market Value of a Share as of the applicable dividend payment date (with the quotient rounded down to the nearest whole number). Once credited to the Participant's account, Dividend Units will be considered Units for all purposes of this Agreement.

Article 10. Tax Withholding

Neither the Company nor any of its Affiliates shall be liable or responsible in any way for the tax consequences relating to the award of Units, their vesting and the settlement of vested Units in Shares. The Participant agrees to determine and be responsible for any and all tax consequences to the Participant relating to the award, vesting and settlement of Units hereunder. If the Company is obligated to withhold an amount on account of any tax imposed as a result of the grant, vesting or settlement of the Units, the provisions of Section 19.2 of the Plan regarding the satisfaction of tax withholding obligations shall apply (including any required payments by the Participant).

Article 11. Transferability

The Units may not be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated, other than by will or by the laws of descent and distribution. Further, except as otherwise provided in a Participant's Award Agreement, a Participant's rights under the Plan shall be exercisable during the Participant's lifetime only by the Participant or the Participant's legal representative. The terms hereof shall be binding on the executors, administrators, heirs and successors of the Participant.

Article 12. Administration

This Agreement and the rights of the Participant hereunder are subject to all the terms and conditions of the Plan, as the same may be amended, modified, suspended or terminated from time to time by the Committee, as well as to such rules and regulations as the Committee may adopt for administration of the Plan. It is expressly understood that the Committee is authorized to administer, construe, and make all determinations necessary or appropriate to the administration of the Plan and this Agreement, in its sole discretion, all of which shall be binding upon the Participant.

Any inconsistency between the Agreement and the Plan shall be resolved in favor of the Plan.

Article 13. Miscellaneous

(a) The selection of any employee for participation in the Plan shall not give such Participant any right to be retained in the employ of the Company. The right and power of the Company to dismiss or discharge any Participant at-will, is specifically reserved. Such Participant or any person claiming under or through the Participant shall not have any right or interest in the Plan or any Award thereunder, unless and until all terms, conditions, and provisions of the Plan that affect such Participant have been complied with as specified herein.

(b) With the approval of the Board, the Committee may terminate, amend, or modify the Plan; provided, however, that no such termination, amendment, or modification of the Plan may in any way adversely affect the Participant's rights under this Agreement without the Participant's written consent, except as required by law.

(c) Participant shall not have voting rights with respect to the Units. Participant shall obtain voting rights with respect to any Shares issued upon settlement of the Units.

(d) This Agreement shall be subject to all applicable laws, rules, and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required.

(e) To the extent not preempted by federal law, this Agreement shall be governed by, and construed in accordance with, the laws of the State of South Dakota.

(f) Any awards received by Participant are subject to the provisions of the Stock Ownership Guidelines approved by the Board of Directors.

(g) Waiver and Modification. The provisions of this Agreement may not be waived or modified unless such waiver or modification is in writing and signed by the Company.

(h) Severability. In the event any provision of this Agreement shall be held to be illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining parts of this Agreement, and the Agreement shall be construed and enforced as if the illegal or invalid provision had not been included.

Black Hills Corporation   Participant

__________________________________   __________________________________

Amy K. Koenig, Vice President – Governance,
Corporate Secretary and Deputy General Counsel

Appendix A

Earned Units and Performance Measures

The determination of the number of Units that will be earned and vested as of the Scheduled Vesting Date specified above will be determined as follows:

Performance Measure (each as defined below)	Weighting	Performance Goal		Award Multiplier
Relative TSR	70%	Maximum	90th Percentile	200%
		Target	50th Percentile	100%
		Threshold	25th Percentile	25%
Average EPS as Adjusted	10%	Maximum	$4.516	200%
		Target	$4.105	100%
		Threshold	$3.695	25%
Average Cost to Serve	10%	Maximum	39.1%	200%
		Target	43.4%	100%
		Threshold	47.7%	25%
Natural Gas Emissions Reduction by 2035	10%	Maximum	38 miles per average year	200%
		Target	29 miles per average year	100%
		Threshold	22 miles per average year	25%

Based on the actual level of achievement of each Performance Measure, the applicable Award Multiplier will be calculated from the table above by determining where the Company's actual performance falls relative to the Performance Goals specified in the applicable column of the table, and then selecting the corresponding Award Multiplier associated with each Performance Measure. If the actual amount of any of these Performance Measures is between two Performance Goal amounts shown in the applicable column of the table, the corresponding Award Multiplier will be determined by linear interpolation between the two relevant Award Multipliers shown in the table. If the actual amount of any of the Performance Measures for the Performance Period is less than the corresponding Threshold Performance Goal specified in the table, the corresponding Award Multiplier is zero, and if it is greater than the corresponding Maximum Performance Goal specified in the table, the corresponding Award Multiplier will be equal to the percentage specified for the Maximum Performance Goal.

Notwithstanding the foregoing, (i) if absolute TSR is negative during the Performance Period, the total number of Earned Units for the achievement of the Relative TSR Performance Goal will not exceed Target and (ii) if Relative TSR is below Threshold, but absolute TSR is above 35%, the Relative TSR Performance Measure will be deemed to be satisfied at Threshold.

The number of Performance Units earned during the Performance Period that will vest as of the Vesting Date will be calculated using the following formula:

[Relative TSR Weighting x (Target Number of Performance Units + Dividend Units credited during the Performance Period and before the Scheduled Vesting Date)] x Relative TSR Award Multiplier
+
[Average EPS as Adjusted Weighting x (Target Number of Performance Units + Dividend Units credited during the Performance Period and before the Scheduled Vesting Date)] x Average EPS as Adjusted Award Multiplier
+
[Average Cost to Serve Weighting x (Target Number of Performance Units + Dividend Units credited during the Performance Period and before the Scheduled Vesting Date)] x Average Cost to Serve Award Multiplier

where:

- The "Relative TSR Weighting," "Average EPS as Adjusted Weighting," "Average EPS as Adjusted Weighting" and the applicable "Award Multiplier" are derived from the table above,

- "Target Number of Performance Units" is the number set forth at the beginning of this Agreement; and

- Dividend Units is defined in Section 8 of the Agreement.

Relative TSR Calculation

For this purpose, Total Shareholder Return (TSR) shall be determined as follows (rounded to nearest basis point):

$$\text{Total Shareholder Return} = \frac{\text{Change in Stock Price + Dividends Paid}}{\text{Beginning Stock Price}}$$

Beginning Stock Price shall mean the average closing price (rounded to nearest cent $xx.xx) on the applicable stock exchange of one share of Common Stock for the ten (10) trading days preceding the grant date; Ending Stock Price shall mean the average closing price (rounded to nearest cent $xx.xx) on the applicable stock exchange of one share of stock for the last ten (10) trading days of the Performance Period; Change in Stock Price shall mean the difference between the Beginning Stock Price and the Ending Stock Price; and Dividends Paid shall mean the total of all dividends (unrounded) on one (1) share of stock with Dividend Payable Dates during the Performance Period. Following the TSR determination, the Company's Percentile Rank shall be determined as follows:

Percentile Rank shall be determined by listing from highest TSR to lowest TSR each company in the Peer Index (excluding the Company) as described on Appendix B. The top company would have a one hundred percentile (100%) rank and the bottom company would have a zero percentile (0.0%) rank. Each company in between would be one hundred divided by n minus one (100/(n-1)) (rounded to nearest basis point - x.xx%) above the company below it, where "n" is the total number of companies in the Peer Index. The Company percentile rank would then be interpolated based on the Company TSR, resulting in the Company's Relative TSR.

If the Company's or any Peer Index company's stock splits (or if there are other similar subdivisions, consolidations or changes in such company's stock or capitalization), such company's

TSR performance will be proportionately adjusted for the stock split or other change so as not to give an advantage or disadvantage to such company by comparison to the other Peer Index companies.

Average EPS as Adjusted Calculation

Average EPS as Adjusted is defined as diluted earnings per share calculated in accordance with GAAP, adjusted for material, non-recurring events (such as impairment charges, one-time events, external acquisition costs, changes to accounting rules, etc.).

Average Cost to Serve Calculation

Average Cost to Serve is defined as non-fuel operations and maintenance (O&M) expense divided by gross margin calculated in accordance with GAAP, adjusted for material, non-recurring events that are approved by the Company's Audit Committee (such as impairment charges, one-time tax events, changes to accounting rules, etc.). No adjustment shall be made to normalize the impact of extreme weather.

Appendix B

Companies Included in the Performance Peer Group for Relative TSR Performance Purposes, Excluding Black Hills Corporation

The Performance Peer Group for Relative TSR performance purposes consist of all companies approved by the Compensation Committee of Black Hills Corporation on January 25, 2024. In the event a member of the Performance Peer Group is impacted by M&A activity during the performance period, the member shall be removed from the Performance Peer Group upon announcement of the transaction. If the Performance Peer Group drops below 12 members, the Compensation Committee of Black Hills Corporation may in its sole discretion modify the Performance Peer Group.

Companies included in the Performance Peer Group for Relative TSR performance purposes at the beginning of the Performance Period, excluding Black Hills Corporation, are listed below:

ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
Atmos Energy Corporation	ATO
Avista Corporation	AVA
CMS Energy Corporation	CMS
Hawaiian Electric Industries, Inc.	HE
IDACORP, Inc.	IDA
MGE Energy, Inc.	MGEE
New Jersey Resources Corporation	NJR
NiSource Inc.	NI
Northwest Natural Holding Company	NWN
NorthWestern Energy Group, Inc.	NWE
OGE Energy Corp.	OGE
ONE Gas, Incl	OGS
Pinnacle West Capital Corporation	PNW
Portland General Electric Company	POR
PNM Resources, Inc.	PNM
Spire, Inc.	SR

BLACK HILLS CORPORATION COMPANY POLICY	
Affected Business Unit(s): All	**Originating Department(s):** Governance **Effective Date:** 12-07-2011
Policy No.: Corp-Governance-01	**Revision Date:** 08-17-2023

Insider Trading Policy

1. PURPOSE

The purchase or sale of securities while possessing material nonpublic ("insider") information or the selective disclosure of such information to others who may trade is prohibited by Federal and state laws. As an essential part of your work, you may have access to material nonpublic information about Black Hills Corporation or its subsidiaries (collectively, the "Company") or about the Company's business (including information about other companies with which the Company does or may do business).

The Company has adopted this Policy to avoid even the appearance of improper conduct on the part of any Company employee. The Company has earned a reputation for conducting business with integrity and ethical conduct. This Policy is designed to further the reputation of the Company and each employee for integrity and good corporate citizenship.

2. SCOPE

This Policy applies to all directors, officers and employees of the Company.

3. POLICY

No director, officer or employee who has material nonpublic information relating to the Company nor any related or other person living in that person's household may buy or sell securities of the Company or engage in any other action to take advantage of, or pass on to others, that information.

This Policy applies to all transactions in the Company's securities, including purchases and sales, as well as gifts of the Company's securities, provided that this Policy shall not apply to bona fide gifts of the Company's securities to persons subject to all the restrictions of this Policy (such as family members living in the person's household) or others, unless the individual making the gift knows or is reckless in not knowing that the recipient intends to sell the securities while the donor is in possession of material, non-public information about the Company.

This Policy also applies to the securities of any other company with respect to information relating to that company obtained in the course of employment with Black Hills Corporation or any of its subsidiaries. A director, officer or employee who learns of material, nonpublic information about a company with whom the Company does or may do business (including customers, suppliers or potential acquisition or strategic partners), as well as any competitor of the Company, should not trade in that company's securities until the information becomes public.

Transactions that may be necessary or justifiable for independent reasons (such as the need to raise money for an emergency expenditure) are no exception. The securities laws do not recognize such mitigating circumstances and even the appearance of an improper transaction must be avoided to preserve the Company's reputation for adhering to the highest standards of conduct.

4. DEFINITION OF MATERIAL NONPUBLIC INFORMATION

4.1 "Material" Information

Any information that a reasonable investor would consider important in a decision to buy, hold or sell securities. Either positive or negative information may be material. In short, any information which could reasonably be expected to affect trading in the Company's stock or other securities is considered material.

Common examples of information that will frequently be regarded as material are:

4.1.1 Financial performance, earnings information and quarterly results;

4.1.2 Guidance on earnings estimates;

4.1.3 Mergers and acquisitions or the sale of significant assets;

4.1.4 Significant accounting matters, including the impairment or changes in asset values;

4.1.5 New products, contracts with suppliers, or developments regarding major customers or suppliers (e.g., the acquisition or loss of a contract);

4.1.6 Changes in auditors or a determination that the Company's financial statements can no longer be relied upon;

4.1.7 Events regarding the Company's securities (e.g., defaults on senior securities, change in debt ratings, calls of securities for redemption, repurchase plans, stock splits or changes in dividends, changes to the rights of securityholders, public or private sales of additional securities or information related to any additional funding);

4.1.8 Significant changes in senior management or the board of directors;

4.1.9 Significant changes in operations;

4.1.10 Significant litigation or government investigations;

4.1.11 Bankruptcies, receiverships or financial liquidity problems; and

4.1.12 Regulatory approvals or changes in regulations and any analysis of how they affect the Company.

The above list is only illustrative; many other types of information may be considered "material," depending on the circumstances. The materiality of particular information is subject to reassessment on a regular basis.

4.2 "Nonpublic" Information

Any information which has not been disclosed generally to the marketplace. Information about the Company that is not yet in general circulation should be considered nonpublic. Similarly, information received about another company in circumstances indicating that it is not yet in general circulation should be considered nonpublic. All information that you learn about the Company or its business plans in connection with your employment is potentially "insider" information until publicly disclosed or made available to the public by the Company. You should treat all such information as confidential and proprietary to the Company. You may not disclose it to others, such as family, relatives, business or social acquaintances, who do not need to know it for legitimate business reasons. **If this nonpublic information is also "material", you are required by law and the Company policy to refrain from trading in Company securities and from passing the information on to others who may trade.**

5. MATERIAL NONPUBLIC INFORMATION

5.1 Prohibited Transactions

When you know of material, nonpublic information about the Company, you, your spouse and members of your immediate family living in your household are prohibited from the following activities:

5.1.1 Trading in Black Hills Corporation securities (including trading in puts and calls for Black Hills Corporation's securities);

5.1.2 Having others trade for you in Black Hills Corporation securities; and

5.1.3 Disclosing the information to anyone else who might then trade.

Neither you nor anyone acting on your behalf nor anyone who learns the information from you (including your spouse and family members) can trade. This prohibition continues whenever and for as long as you know material, nonpublic information.

These prohibitions also apply to the securities of any other company with respect to information relating to that company obtained in the course of employment with Black Hills Corporation or any of its subsidiaries.

5.2 Transactions by Family Members

The very same restrictions apply to your family members who reside with you, anyone else who lives in your household, and any family members who do not live in your household but whose transactions in the Company's securities are directed by you or are subject to your influence or control. Directors, officers and employees are expected to be responsible for the compliance of their immediate family and personal household and therefore should make them aware of the need to confer with them before they trade in Black Hills Corporation securities.

5.3 Twenty-Twenty Hindsight

Remember, if securities transactions become the subject of scrutiny, they will be viewed after-the-fact with the benefit of hindsight. As a result, before engaging in any transaction an employee should carefully consider how regulators and others might view such transaction in hindsight.

5.4 Tipping Information to Others

Whether the information is proprietary information about the Company or information that could have an impact on Black Hills Corporation or another company's stock price, directors, officers and employees of the Company must not pass the information on to others.

5.5 When Information is Public

It would be improper for a director, officer or employee to enter a trade immediately after the Company has made a public announcement of material information, including earnings releases.

Because the Company's shareholders and the investing public should be afforded the time to receive the information and act upon it, as a general rule you should not engage in any transaction in the Company's securities until at least 48 hours after the date the information has been released to the public.

5.6 Section 10b5-1 Trading Program

Notwithstanding the prohibition against insider trading, Rule 10b5-1 of the Securities Exchange Act of 1934 and this Policy permit directors, officers and employees to trade in Black Hills Corporation securities while aware of material, nonpublic information, so long as the trades occur pursuant to a binding contract, instruction or written trading program that was put into place at a time when the trader was not aware of material, nonpublic information that otherwise complies with the requirements of Rule 10b5-1. Transactions made pursuant to a plan meeting the requirements of Rule 10b5-1 need not be pre-cleared as set forth above, so long as the following requirements have been met:

5.6.1 The form of the Rule 10b5-1 trading plan that you propose to execute must:

5.6.1.1. Be delivered to, and approved by the General Counsel or Corporate Secretary prior to adoption or amendment of the trading plan;

5.6.1.2. Include an affirmation that you are not aware of material nonpublic information about the Company or its securities;

5.6.1.3. Include an affirmation that you are adopting the plan in good faith and not as part of a plan or scheme to evade the prohibitions of Rule 10b-5 of the Exchange Act; and

5.6.1.4. Includes a "cooling off" period for (i) Section 16 officers and directors that extends to the later of 90 days after adoption or modification of the trading plan or two business days after filing the Form 10-K or Form 10-Q covering the fiscal quarter in which the trading plan was adopted, up to a maximum of 120 days; and (ii) other employees, other than the Company, that extends 30 days after adoption or modification of the trading plan.

5.6.2 If applicable to you, you must comply with the requirements of Rule 144 under the Securities Act of 1933, and make or cause to be made all necessary filings, including Rule 144 filings, filings pursuant to Section 13 and Section 16 of the Securities Exchange Act of 1934, and any other filings necessary pursuant to the Securities Act and/or the Exchange Act; and

5.6.3 You must establish the Rule 10b5-1 trading program at a time when you are not in possession of material, non-public information about the Company.

You must consult with your own legal counsel and other financial advisors in connection with your decision to enter into a Rule 10b5-1 trading program, and determine, based upon their advice, whether the plan you propose to execute meets the criteria set forth in Rule 10b5-1.

6. TRANSACTIONS UNDER COMPANY PLANS

6.1 Trading in the Company 401(k) Plan

This Policy applies to certain transactions involving Company stock in an employee's 401(k) Plan account. For example, the Policy applies to:

6.1.1 Elections to make intra-plan transfers into or out of the Company stock fund; and

6.1.2 Elections to increase or decrease the percentage allocation of new investments in the 401(k) Plan to the Company stock fund.

The Policy does not apply, however, to repetitive investments in the Company stock fund which occur every pay period pursuant to a payroll deduction in a like amount each pay period.

6.2 Stock Option Exercises and Stock Unit Vesting

This Policy does not apply to the exercise of an employee stock option or the vesting of stock units (restricted stock units or performance stock units) or the forfeiture of shares to the Company to satisfy any exercise price and/or tax withholding obligation.

The Policy does apply, however, to any sale of stock as part of a broker-assisted cashless exercise of a stock option, or any market sale of stock received upon exercise of a stock option or vesting of a stock unit for the purpose of generating the cash needed to pay the exercise price of an option or required tax withholding.

6.3 Dividend Reinvestment Plan

This Policy does not apply to purchases of Black Hills Corporation securities under the Company's Dividend Reinvestment and Direct Stock Purchase Plan resulting from your reinvestment of dividends paid on Black Hills Corporation securities or the systematic monthly purchases of Black Hills Corporation securities under the optional cash investment feature of the plan.

This Policy does apply, however, to voluntary purchases of Black Hills Corporation securities resulting from your election to participate in the plan or your increase in the level of participation in the plan. The Policy also applies to your sale of any securities of Black Hills Corporation purchased pursuant to the plan.

7. ADDITIONAL PROHIBITED TRANSACTIONS

The Company considers it improper and inappropriate for any director, officer or other employee of the Company to engage in short-term or speculative transactions in Black Hills Corporation securities. It is therefore Company policy that directors, officers and other employees may not engage in any of the following transactions:

7.1 Short-Term Trading

An employee's short-term trading of Black Hills Corporation securities may be distracting to the employee and may unduly focus the employee on the Company's short-term stock market performance instead of the Company's long-term business objectives. For these reasons, any director, officer or other employee of the Company who purchases Black Hills Corporation securities in the open market may not sell any Black Hills Corporation securities of the same class during the six months following the purchase.

7.2 Short Sales

Short sales of Black Hills Corporation securities evidence an expectation on the part of the seller that the securities will decline in value, and therefore signal to the market that the seller has no confidence in Black Hills Corporation or its short-term prospects. In addition, short sales may reduce the seller's incentive to improve Black Hills Corporation performance. For these reasons, short sales of Black Hills Corporation securities are prohibited by this Policy. In addition, Section 16(c) of the Securities Exchange Act of 1934 prohibits Section 16 officers and directors from engaging in short sales.

7.3 Publicly Traded Options

A transaction in options is, in effect, a bet on the short-term movement of Black Hills Corporation stock and therefore creates the appearance that the director, officer or employee is trading based on inside information. Transactions in options also may focus the director, officer or employee's attention on short-term performance at the expense of the Company's long-term objectives. Accordingly, transaction in puts, calls or other derivative securities, on an exchange or in any other organized market, are prohibited by this Policy.

7.4 Hedging Transactions

Certain forms of hedging or monetization transactions, such as zero-cost collars, equity swaps, forward sale contracts and exchange funds, allow a director, officer, or employee to lock in much of the value of his or her stock holdings, often in exchange for all or part of the potential for upside appreciation in the stock. These transactions allow the director, officer or employee to continue to own the covered securities, but without the full risks and rewards of ownership. When that occurs, the director, officer or employee may no longer have the same objectives as the Company's other shareholders. Therefore, hedging transactions are prohibited by this Policy.

7.5 Margin Accounts and Pledges

Securities held in margin account may be sold by the broker without the customer's consent if the customer fails to meet a margin call. Similarly, securities pledged as collateral for a loan may be sold in foreclosure if the borrower defaults on the loan. Because a margin sale or foreclosure sale may occur at a time when the pledgor is aware of material nonpublic information or otherwise is not permitted to trade in Black Hills Corporation securities, directors, officers and employees are prohibited from holding Black Hills Corporation securities in a margin account or pledging Black Hills Corporation securities as collateral for a loan.

8. POST-TERMINATION TRANSACTIONS

This Policy continues to apply to your transactions in Black Hills Corporation securities even after you have terminated employment. If you are in possession of material nonpublic information when your employment terminates, you may not trade in Black Hills Corporation securities until that information has become public or is no longer material.

9. BLACKOUT PERIODS

9.1 Quarterly Blackout Periods

The Company prohibits directors, officers and all employees who have received equity under the Company's equity compensation program, from buying or selling Black Hills Corporation securities during a period of time beginning 10 business days before the last day of each fiscal quarter, until 48 hours following the release of quarterly earnings.

9.2 Event Specific Blackout Periods

From time to time, an event may occur that is material to the Company and is known by only a few directors or employees. So long as the event remains material and nonpublic, directors, officers, and such other persons as are designated by the General Counsel or Corporate Secretary may not trade in Black Hills Corporation securities. The existence of an event-specific blackout will not be announced, other than to those who are aware of the event giving rise to the blackout. If, however, a person whose trades are subject to preclearance requests permission to trade in Black Hills Corporation securities during an event-specific blackout, the General Counsel or Corporate Secretary may inform the requestor of the existence of a blackout period, without disclosing the reason for the blackout. Any person made aware of the existence of an event-specific blackout should not disclose the existence of the blackout to any other person. The failure of the General Counsel or Corporate Secretary to designate a person as being subject to an event-specific blackout will not relieve that person of the obligation not to trade while aware of material nonpublic information.

In addition, Section 306(a) of the Sarbanes-Oxley Act of 2002 prohibits any director or Section 16 officer of the Company from, directly or indirectly, purchasing, selling or otherwise acquiring or transferring any equity security of the Company during a pension plan blackout period that prevents plan participants and beneficiaries from engaging in transactions involving issuer equity securities held in their plan accounts. These prohibitions apply only if the securities acquired or disposed of by the director or officer were acquired in connection with his or her service or employment as a director or officer. Officers and directors will be notified of an impending pension plan blackout period. Regulations promulgated pursuant to Section 306 (a) further define the type of securities subject to the prohibition, as well as exemptions from the trading prohibition.

10. PRE-CLEARANCE OF ALL TRADES BY DIRECTORS, OFFICERS AND KEY EMPLOYEES

To provide assistance in preventing inadvertent violations and avoiding even the appearance of an improper transaction (which could result, for example, where an employee engages in a trade while unaware of a pending major development), the procedures set forth below must be followed by the Company's directors, officers, and other employees who may have access to material nonpublic information:

All transactions in Black Hills Corporation stock (acquisitions, dispositions, transfers, etc., including discretionary transactions in Company plans) by directors, officers and all employees who have received equity under the Company's equity compensation program must be pre-cleared by the Senior Vice President-General Counsel or the Corporate Secretary of the Company. Individuals who are not directors or officers but who are subject to the pre-clearance policy will be so notified. This requirement does not apply to gifts or stock option exercises, but would cover market sales of option stock, including cashless exercises.

11. RULE 144 AND SECTION 16 COMPLIANCE FOR DIRECTORS AND EXECUTIVE OFFICERS

Members of the Board of Directors of the Company, and those individuals specified by the Company as Section 16 officers for purposes of Rule 144 and Section 16 (and only these individuals) are also subject to additional Section 16 trading prohibitions (short-swing profit rules), as well as very stringent transaction reporting requirements under Rule 144 and Section 16. Those individuals should familiarize themselves with these rules and regulations. If you are subject to Rule 144 and Section 16 compliance, you may obtain information on these rules and regulations from the Vice President-Governance. Generally, directors and executive officers must file with the Securities and Exchange Commission a Form 144 no later than the end of any business day that an order for sale is placed or a sale of the Company securities occurs. A **Form 3**, **Form 4** or **Form 5** is also required to be filed with the Securities and Exchange Commission by a director or executive officer of the Company for transactions involving the securities of the Company. In this regard, the Manager-Equity Compensation and Shareholder Services will assist in the preparation and filing of the necessary Form 4s by preparing the applicable form for signature by the individual director or Section 16 officer based upon information furnished by such individual and filing the executed forms with the Securities and Exchange Commission as promptly as possible (generally due within two business days of a transaction). Form 144s are expected to be prepared and filed by the individual director of Section 16 officer's broker. Under the law, the individual director or Section 16 officer is obligated to file appropriate forms in a timely manner and to refrain from engaging in any unlawful transactions. The Company cannot and does not assume any legal responsibility in this regard, but the Manager-Equity Compensation and Shareholder Services will assist in accordance with the procedures outlined in this Section 11.

12. UNAUTHORIZED DISCLOSURE

Serious problems could arise for the Company and you by any unauthorized disclosure of nonpublic information about the Company or its customers, whether or not for the purpose of facilitating improper trading in Company securities. It is the Company's policy that you should not discuss nonpublic Company matters or developments relating to the Company or its customers with anyone outside of the Company (including family members, relatives and friends), except as required in the performance of your regular employment duties. Similarly, you should not discuss Company affairs in public or quasi-public areas where your conversation may be overheard (e.g., airplanes, restaurants, restrooms, elevators, etc.). This prohibition also applies to inquiries about the Company which may be made by the press, investment analysts or others in the financial community, including shareholders. It is important that all such communications on behalf of the Company be made only through authorized individuals. Unless you are expressly authorized to respond to inquiries of this nature, you should decline comment and refer the inquirer to the Company's Director of Investor Relations.

13. CONSEQUENCES

The consequences of insider trading violations can be significant.

13.1 Individuals

Individuals who trade on inside information (or tip information to others) face sanctions of (a) a civil penalty of up to three times the profit gained or loss avoided, (b) criminal fines of up to $1.0 million (no matter how small the profit), and (c) a jail term.

Moreover, **a breach of Black Hills Corporation Policy regarding insider trading [or unauthorized disclosure] may be grounds for [disciplinary action, which may be up to and include termination of employment]**. Needless to say, any of the above consequences, even an investigation by the Securities and Exchange Commission that does not result in prosecution, can tarnish one's reputation and irreparably damage a career.

13.2 Company

A company (as well as possibly any supervisory person) that fails to take appropriate steps to prevent illegal trading faces sanctions of (a) a civil penalty of the greater of $1.0 million or three times the profit gained or loss avoided as a result of the employee's violation, and (b) a criminal penalty.

14. COMPANY ASSISTANCE

If you have any questions about whether information received by you about the Company (or any corporation with whom we do business) is inside information, you should refrain from trading or disclosing such information until you first determine that such information is public, nonmaterial, or both. When in doubt, consult with the Company's Corporate Secretary or General Counsel. Remember however, the ultimate responsibility for adhering to the Policy and avoiding improper transactions rests with you. It is imperative that you use your best judgment.

15. REVISION HISTORY

Revision #	Revision Date	Description	Revised By
New	12-07-2001	New Policy	Sr. Management
2	12-08-2017	Prohibit all pledging of company stock by employees	Sr. Management
3	11-09-2020	Transferred policy to new template and annual review	Sr. Management
4	08-17-2023	Updated examples of material information to align with other Company policies, revised references to key employees to say all employees who have received equity under the Company's equity compensation plan, removed executive and replaced with Section 16 when referring to impacted officers, and updated to conform to revised 10b5-1 plan SEC rules.	Sr. Management
(List every instance of the document being changed or reissued).			

Exhibit 21

BLACK HILLS CORPORATION
SUBSIDIARIES
December 31, 2023

	Subsidiary Name	State of Origin
1.	Black Hills Colorado Electric, LLC *	Delaware
2.	Black Hills Colorado Gas, Inc. *	Colorado
3.	Black Hills Colorado IPP, LLC *	South Dakota
4.	Black Hills Colorado Wind, LLC	Delaware
5.	Black Hills Electric Generation, LLC *	South Dakota
6.	Black Hills Electric Parent Holdings, LLC	South Dakota
7.	Black Hills Energy Arkansas, Inc. *	Arkansas
8.	Black Hills Energy Renewable Resources, LLC	South Dakota
9.	Black Hills Energy Services Company *	Colorado
10.	Black Hills Exploration and Production, Inc. *	Wyoming
11.	BHERR Holdings, LLC	South Dakota
12.	Black Hills Gas, Inc.	Delaware
13.	Black Hills Gas, LLC	Delaware
14.	Black Hills Gas Holdings, LLC	Delaware
15.	Black Hills Gas Parent Holdings II, Inc.	Delaware
16.	Black Hills Gas Resources, Inc. *	Colorado
17.	Black Hills/Iowa Gas Utility Company, LLC *	Delaware
18.	Black Hills/Kansas Gas Utility Company, LLC *	Kansas
19.	Black Hills Nebraska Gas, LLC *	Delaware
20.	Black Hills Non-regulated Holdings, LLC	South Dakota
21.	Black Hills Plateau Production, LLC *	Delaware
22.	Black Hills Power, Inc. *	South Dakota
23.	Black Hills Service Company, LLC *	South Dakota
24.	Black Hills Shoshone Pipeline, LLC *	Wyoming
25.	Black Hills Utility Holdings, Inc. *	South Dakota
26.	Black Hills Wyoming, LLC	Wyoming
27.	Black Hills Wyoming Gas, LLC *	Wyoming
28.	Cheyenne Light, Fuel and Power Company *	Wyoming
29.	Mallon Oil Company, Sucursal Costa Rica	Costa Rica
30.	N780BH, LLC	South Dakota
31.	Rocky Mountain Natural Gas LLC *	Colorado
32.	Wyodak Resources Development Corp. *	Delaware

* doing business as **Black Hills Energy**

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-272739 on Form S-3 and Registration Statement Nos. 333-170451, 333-217679, 333-170448, 333-170452, and 333-203714 on Form S-8 of our reports dated February 14, 2024, relating to the consolidated financial statements of Black Hills Corporation and subsidiaries (the “Company”), and the effectiveness of the Company’s internal control over financial reporting, appearing in this Annual Report on Form 10-K of Black Hills Corporation for the year ended December 31, 2023.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 14, 2024

Exhibit 31.1

CERTIFICATION

I, Linden R. Evans, certify that:

1. I have reviewed this Annual Report on Form 10-K of Black Hills Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting.

5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of registrant’s board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 14, 2024

/s/ Linden R. Evans

Linden R. Evans

President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Kimberly F. Nooney, certify that:

1. I have reviewed this Annual Report on Form 10-K of Black Hills Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 14, 2024

/s/ Kimberly F. Nooney

Kimberly F. Nooney

Senior Vice President and Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Black Hills Corporation (the “Company”) on Form 10-K for the year ended December 31, 2023 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Linden R. Evans, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13 (a) or 15 (d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 14, 2024

/s/ Linden R. Evans

Linden R. Evans
President and Chief Executive Officer

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Black Hills Corporation (the “Company”) on Form 10-K for the year ended December 31, 2023 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Kimberly F. Nooney, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13 (a) or 15 (d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 14, 2024

/s/ Kimberly F. Nooney

Kimberly F. Nooney
Senior Vice President and Chief Financial Officer

Exhibit 95

Information concerning mine safety violations or other regulatory matters required by Sections 1503(a) of Dodd-Frank is included below.

Mine Safety and Health Administration Safety Data

Safety is a core value at Black Hills Corporation and at each of its subsidiary operations. We have in place a comprehensive safety program that includes extensive health and safety training for all employees, site inspections, emergency response preparedness, crisis communications training, incident investigation, regulatory compliance training and process auditing, as well as an open dialogue between all levels of employees. The goals of our processes are to eliminate exposure to hazards in the workplace, ensure that we comply with all mine safety regulations, and support regulatory and industry efforts to improve the health and safety of our employees along with the industry as a whole.

Under the recently enacted Dodd-Frank Act, each operator of a coal or other mine is required to include certain mine safety results in its periodic reports filed with the SEC. Our mining operation, consisting of Wyodak Coal Mine, is subject to regulation by the federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the “Mine Act”). Below we present the following information regarding certain mining safety and health matters for the twelve month period ended December 31, 2023. In evaluating this information, consideration should be given to factors such as: (i) the number of citations and orders will vary depending on the size of the coal mine, (ii) the number of citations issued will vary from inspector to inspector and mine to mine, and (iii) citations and orders can be contested and appealed, and in that process, are often reduced in severity and amount, and are sometimes dismissed. The information presented includes:

- Total number of violations of mandatory health and safety standards that could significantly and substantially contribute to the cause and effect of a coal or other mine safety or health hazard under section 104 of the Mine Act for which we have received a citation from MSHA;
- Total number of orders issued under section 104(b) of the Mine Act;
- Total number of citations and orders for unwarrantable failure of the mine operator to comply with mandatory health and safety standards under section 104(d) of the Mine Act;
- Total number of imminent danger orders issued under section 107(a) of the Mine Act; and
- Total dollar value of proposed assessments from MSHA under the Mine Act.

The table below sets forth the total number of citations and/or orders issued by MSHA to BHE – Wyodak Mine under the indicated provisions of the Mine Act, together with the total dollar value of proposed MSHA assessments received during the twelve months ended December 31, 2023 and legal actions pending before the Federal Mine Safety and Health Review Commission, together with the Administrative Law Judges thereof, for BHE – Wyodak Mine, our only mining complex. All citations were abated within 24 hours of issue.

Mine/ MSHA Identification Number	Mine Act Section 104 S&S Citations issued during twelve months ended December 31, 2023	Mine Act Section 104(b) Orders (#)	Mine Act Section 104(d) Citations and Orders (#)	Mine Act Section 110(b)(2) Violations (#)	Mine Act Section 107(a) Imminent Danger Orders (#)	Total Dollar Value of Proposed MSHA Assessments (a)	Total Number of Mining Related Fatalities (#)	Received Notice of Potential to Have Pattern Under Section 104(e) (yes/no)	Legal Actions Pending as of Last Day of Period (#) (b)	Legal Actions Initiated During Period (#)	Legal Actions Resolved During Period (#)
Wyodak Coal Mine - 4800083	1	0	0	0	0	$ 2,050	0	No	0	0	0

(a) The types of proceedings by class: (1) Contests of citations and orders – none; (2) contests of proposed penalties – none; (3) complaints for compensation – none; (4) complaints of discharge, discrimination or interference under Section 105 of the Mine Act – none; (5) applications for temporary relief – none; and (6) appeals of judges' decisions or orders to the FMSHRC – none.

	BLACK HILLS CORPORATION POLICY
Affected Business Unit(s): **All**	**Originating Department(s): Governance** **Effective Date: December 1, 2023**
Policy No.: Corp-Governance-05	**Revision Date:**
Title: Mandatory Compensation Recovery Policy (applicable to current and former Section 16 Officers)	

1. PURPOSE

The Board of Directors (the "Board") of the Company has adopted this Mandatory Compensation Recovery Policy (this "Policy") pursuant to Rule 10D-1 of the Securities and Exchange Act of 1934, as amended (the "Exchange Act"), the Securities and Exchange Commission ("SEC") regulations promulgated thereunder, and applicable New York Stock Exchange ("NYSE") listing standards.

Subject to and in accordance with the terms of this Policy, upon a Recoupment Event, each Covered Executive shall be obligated to return to the Company, reasonably promptly, the amount of Erroneously Awarded Compensation that was received by such Covered Executive during the Lookback Period.

This Policy will be administered by the Compensation Committee of the Board (the "Committee"). Any determinations made by the Committee will be final and binding on all affected individuals.

2. SCOPE

This Policy shall be binding and enforceable against all Covered Executives (defined in Section 3.2 to be current and former Section 16 Officers) and their beneficiaries, heirs, executors, administrators, or other legal representatives.

3. DEFINITIONS

3.1. Accounting Restatement

"Accounting Restatement" means an accounting restatement due to the material noncompliance of the Company with any financial reporting requirement under the securities laws, including any required accounting restatement to correct an error in previously issued financial statements that is (a) material to the previously issued financial statements (commonly referred to as a "Big R" restatement), or (b) would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period (commonly referred to as a "little r" restatement).

3.2. Covered Executive

"Covered Executive" means each of the Company's current and former Section 16 Officers.

3.3. Erroneously Awarded Compensation

"Erroneously Awarded Compensation" means, with respect to each Covered Executive in connection with an Accounting Restatement, the excess of the amount of Incentive-Based Compensation received by the Covered Executive during the Lookback Period over the amount of Incentive-Based Compensation that otherwise would have been received had it been determined based on the restated amounts, computed without regard to any taxes paid. For Incentive-Based Compensation based on stock price or total shareholder return, where the amount of Erroneously Awarded Compensation is not subject to mathematical recalculation directly from the information in an Accounting Restatement: (a) the amount must be based on a reasonable estimate of the effect of the Accounting Restatement on the stock price or total shareholder return upon which the Incentive-Based Compensation was received; and (b) the Company must maintain documentation of the determination of that reasonable estimate and provide such documentation to NYSE.

3.4. Financial Reporting Measures

"Financial Reporting Measures" are any measures that are determined and presented in accordance with the accounting principles used in preparing the Company's financial statements, and any measures derived wholly or in part from such measures. Stock price and total shareholder return are also Financial Reporting Measures. A Financial Reporting Measure need not be presented within the financial statements or included in a filing with the SEC.

3.5. Incentive-Based Compensation

"Incentive-Based Compensation" is any compensation that is granted, earned, or vested based wholly or in part upon the attainment of a Financial Reporting Measure.

3.6. Lookback Period

"Lookback Period" means the three completed fiscal years immediately preceding the Required Restatement Date and any transition period (that results from a change in the Company's fiscal year) of less than nine months within or immediately following those three completed fiscal years.

3.7. Recoupment Event

A "Recoupment Event" occurs when the Company is required to prepare an Accounting Restatement.

3.8. Required Restatement Date

"Required Restatement Date" means the earlier to occur of: (a) the date the Company's Board, a committee of the Board, or the officer(s) of the Company authorized to take such action if Board action is not required, concludes, or reasonably should have concluded, that the Company is required to prepare an Accounting Restatement, or (b) the date a court, regulator, or other legally authorized body directs the Company to prepare an Accounting Restatement.

3.9. Section 16 Officer

"Section 16 Officer" is defined as an "officer" of the Company within the meaning of Rule 16a-1(f) of the Exchange Act.

3.10. Section 409A

"Section 409A" means Section 409A of the Internal Revenue Code and the regulations and guidance promulgated thereunder.

4. POLICY STATEMENT

4.1. Amount Subject to Recovery

The Incentive-Based Compensation that is subject to recovery under this Policy includes such compensation that is received by a Covered Executive (i) on or after October 2, 2023 (even if such Incentive-Based Compensation was approved, awarded or granted prior to this date), (ii) after the individual began service as a Covered Executive, (iii) if the individual served as a Section 16 Officer at any time during the performance period for such Incentive-Based Compensation, and (iv) while the Company has a class of securities listed on a national securities exchange or national securities association.

The amount of Incentive-Based Compensation subject to recovery from a Covered Executive upon a Recoupment Event is the Erroneously Awarded Compensation, which amount shall be determined by the Committee.

For purposes of this Policy, Incentive-Based Compensation is deemed "received" in the Company's fiscal period during which the Financial Reporting Measure specified in the Incentive-Based Compensation award is attained, even if the payment or grant of the Incentive-Based Compensation occurs after the end of that period.

4.2. Recovery of Erroneously Awarded Compensation

Promptly following a Recoupment Event, the Committee will determine the amount of Erroneously Awarded Compensation for each Covered Executive, and the Company will provide each such Covered Executive with a written notice of such amount and a demand for repayment or return. Upon receipt of such notice, each affected Covered Executive shall promptly repay or return such Erroneously Awarded Compensation to the Company.

If such repayment or return is not made within a reasonable time, the Company shall recover Erroneously Awarded Compensation in a reasonable and prompt manner using any lawful method determined by the Committee; provided that recovery of any Erroneously Awarded Compensation must be made in compliance with Section 409A.

4.3. Limited Exceptions

Erroneously Awarded Compensation will be recovered in accordance with this Policy unless the Committee determines that recovery would be impracticable and one of the following conditions is met:

- the direct expense paid to a third party to assist in enforcing this Policy would exceed the amount to be recovered, provided the Company has first made a reasonable effort to recover the Erroneously Awarded Compensation; or

- the recovery would likely cause a U.S. tax-qualified retirement plan to fail to meet the requirements of Internal Revenue Code Sections 401(a)(13) and 411(a) and the regulations thereunder.

Reliance on any of the above exemptions will further comply with applicable listing standards, including without limitation, documenting the reason for the impracticability and providing required documentation to NYSE.

4.4. No Insurance or Indemnification

Neither the Company nor any of its affiliates or subsidiaries may indemnify any Covered Executive against the loss of any Erroneously Awarded Compensation (or related expenses incurred by the Covered Executive) pursuant to a recovery of Erroneously Awarded Compensation under this Policy, nor will the Company nor any of its affiliates or subsidiaries pay or reimburse a Covered Executive for any insurance premiums on any insurance policy obtained by the Covered Executive to protect against the forfeiture or recovery of any compensation pursuant to this Policy.

4.5. Interpretation

The Committee is authorized to interpret and construe this Policy and to make all determinations necessary, appropriate, or advisable for the administration of this Policy. This Policy shall be applied and interpreted in a manner that is consistent with the requirements of Rule 10D-1 and any applicable regulations, rules or standards adopted by SEC or the rules of any national securities exchange or national securities association on which the Company's securities are listed. In the event that this Policy does not meet the requirements of Rule 10D-1, the SEC regulations promulgated thereunder, or the rules of any national securities exchange or national securities association on which the Company's securities are listed, this Policy shall be deemed to be amended to meet such requirements.

4.6. Indemnification of Policy Administrators

Any members of the Committee who participate in the administration of this Policy shall not be personally liable for any action, determination or interpretation made with respect to this Policy and shall be fully indemnified by the Company to the fullest extent permitted under applicable law and Company governing documents and policies with respect to any such action, determination or interpretation. The foregoing shall not limit any other rights to indemnification of the members of the Committee under applicable law or Company governing documents and policies.

4.7. Amendment; Termination

The Board or the Committee may amend this Policy in its discretion and shall amend this Policy as it deems necessary to comply with the regulations adopted by the SEC under Rule 10D-1 and the rules of any national securities exchange or national securities association on which the Company's securities are listed. The Board or the Committee may terminate this Policy at any time. Notwithstanding anything herein to the contrary, no amendment or termination of this Policy shall be effective if that amendment or termination would cause the

Company to violate any federal securities laws, SEC rules or the rules of any national securities exchange or national securities association on which the Company's securities are listed.

4.8. Other Recoupment Rights

Any right of recoupment under this Policy is in addition to, and not in lieu of, any other remedies or rights of recoupment that may be available to the Company pursuant to the terms of any similar provision in any employment agreement or other compensation plan or agreement and any other legal remedies available to the Company. This Policy is in addition to any other clawback or compensation recovery, recoupment or forfeiture policy in effect or that may be adopted by the Company from time to time, or any laws, rules or listing standards applicable to the Company, including without limitation, the Company's right to recoup compensation subject to Section 304 of the Sarbanes-Oxley Act of 2002. To the extent that application of this Policy would provide for recovery of Erroneously Awarded Compensation that the Company recovers pursuant to another policy or provision, the amount that is recovered will be credited to the required recovery under this Policy.

5. RELATED DOCUMENTS

Black Hills Corporation Supplemental Compensation Recovery Policy

6. REVISION HISTORY

Revision #	Revision Date	Description	Revised By
New		New Policy	
(List every instance of the document being changed or reissued).			