UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2026
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

Former name, former address, and former fiscal year if changed since last report
NONE

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 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 is a shell company (as defined in Rule 12b-2 of the Exchange Act).Yes ☐ No ☒

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

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

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

Class	Outstanding at November 2, 2026
Common stock, $1.00 par value	76,524,804 shares

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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:

Aeolus Transmission Project	Transmission expansion project in Wyoming consisting of two new parallel 230-kV lines, with upgrade capabilities to 345-kV, from PacifiCorp's Aeolus substation to Wyoming Electric's substation. The total project spans approximately 125 miles and is needed to support large-load customer growth in the Cheyenne region and is also expected to provide broader reliability benefits, operational flexibility and enhanced transmission capability to Wyoming Electric's system. Recovery of project costs is expected to be requested under the LCTCAM, which is pending approval from the WPSC.
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).
ASC	Accounting Standards Codification as issued by the FASB
ASU	Accounting Standards Update as issued by the FASB
ATM	At-the-market equity offering program
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-box 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.
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 Electric Parent Holdings	Black Hills Electric Parent Holdings, LLC., a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Energy	The name used to conduct the business of our Utilities
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.
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
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.
Captive	A protected separate cell captive insurance company sponsored by Energy Insurance Services, Inc. (EIS), a nonaffiliated captive insurance company and consolidated VIE of BHC. EIS is owned by Energy Insurance Mutual Limited Company and allows participating member sponsoring organizations, such as BHC, to insure risks using captive entities.
Choice Gas Program	Regulator-approved programs in Wyoming and Nebraska that allow certain utility customers to select their natural gas commodity supplier, providing for the unbundling of the commodity service from the distribution delivery service.
Chief Operating Decision Maker (CODM)	Chief Executive Officer
CIAC	Contribution in aid of construction
Clean Energy Plan	2030 Ready Plan that establishes a roadmap and preferred resource portfolio for Colorado Electric to achieve the State of Colorado's requirement calling upon electric utilities to reduce greenhouse gas emissions by a minimum of 80% from 2005 levels by 2030.
Colorado Electric	Black Hills Colorado Electric, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Parent Holdings, providing electric services 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).
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 the low temperatures 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.
CP Program	Commercial Paper Program
CPCN	Certificate of Public Convenience and Necessity
CPGS	Cheyenne Prairie Generating Station
CPUC	Colorado Public Utilities Commission
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)
ECA	Energy Cost Adjustment is an adjustment that allows us to pass the prudently-incurred cost of fuel and purchased energy through to customers.
EIA	Environmental Improvement Adjustment is an annual adjustment mechanism that allows South Dakota Electric to recover from customers eligible investments in, and expense related to, new environmental measures.
FASB	Financial Accounting Standards Board
FCC	Federal Communications Commission
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States of America
Google	Google, LLC and its affiliates
GSRS	Gas System Reliability Surcharge is a monthly charge that recovers Kansas Gas's costs associated with pipeline safety, integrity, growth, facility, equipment, and government-mandated projects.
GW	Gigawatts
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.
HSR Act	Hart-Scott-Rodino Antitrust Improvements Act of 1976
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).
IRP	Integrated Resource Plan
IRS	United States Internal Revenue Service
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).
KCC	Kansas Corporation Commission
kV	Kilovolt
Lange II	A dual fuel (natural gas and diesel oil) electric generation project in Rapid City, South Dakota with an estimated total capacity of 99 MW. This facility will be owned and operated by South Dakota Electric and will be located adjacent to the Lange CT generation facility. This project is expected to be in service by the end of 2026. The addition of these resources will replace generation facilities planned for retirement and support updated planning reserve margin requirements.
LCTCAM	Large Customer Transmission Cost Adjustment Mechanism
Large Power Contract Service (LPCS) Tariff	Wyoming Electric offers service under the LPCS tariff approved by the Wyoming Public Service Commission. The LPCS Tariff provides a cost-based rate structure for customers with very large electric loads, typically data centers or other high-demand facilities.This Tariff is designed to ensure that service to LPCS customers is fully self-supporting and does not shift costs to other customer classes.
Merger	Merger Sub merging with and into NorthWestern
Merger Agreement	The Agreement and Plan of Merger, dated August 18, 2025, by and among BHC, Merger Sub, and NorthWestern
Merger Sub	River Merger Sub Inc., a Delaware corporation and direct, wholly owned subsidiary of BHC
Microgrid	A localized electrical network that can operate independently or in conjunction with the main power grid and is capable of generating, distributing, and controlling the flow of electricity within a defined area.
MMBtu	Million British thermal units
Moody's	Moody's Ratings
MPSC	Montana Public Service Commission
MW	Megawatts

MWh	Megawatt-hours
N/A	Not applicable
Nameplate capacity	The maximum rated output of a generating unit.
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).
NorthWestern	NorthWestern Energy Group, Inc., a Delaware corporation
NPSC	Nebraska Public Service Commission
OCI	Other Comprehensive Income
Phase-in Plan Rate (PIPR) Rider	South Dakota law provides for a utility to begin recovering costs outside of a general rate review for investments in new generation facilities.
PPA	Power Purchase Agreement
PTC	Production Tax Credit
Ready Wyoming	A 260-mile, multi-phase transmission expansion project in Wyoming which was fully completed and placed in service in 2025. The project provides customers long-term price stability and greater flexibility as power markets develop in the western United States. This project is also expected to enable economic growth in Wyoming, expand access to renewable resources and facilitate additional renewable development across wind- and sun-rich resource areas.
Reserve margin	The capacity held above projected peak load to maintain reliability.
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 31, 2024, and will terminate on May 31, 2030. 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.
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 ongoing monthly service agreements to residential utility customers.
S&P	S&P Global Ratings, a division of S&P Global Inc.
South Cheyenne Transmission Project	Transmission expansion project to expand infrastructure in southern Wyoming. The project includes new substations and nearly 15 miles of transmission lines and upgrades to be in-service in multiple phases in late 2027 through 2028. Recovery of project costs is expected to be requested under the LCTCAM, which is currently pending with the WPSC.
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).
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.
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.
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.
TFA	Transmission Facility Adjustment is an annual adjustment mechanism that allows South Dakota Electric to recover charges for qualifying new and modified transmission facilities from customers.
Utilities	Black Hills' Electric and Gas Utilities
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.
Wildfire Mitigation Plan (WMP)	Our three-layered approach to manage wildfire risks driven by asset-based risk assessments that include asset programs, integrity programs and operational response.
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).
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).

FORWARD-LOOKING INFORMATION

This Quarterly Report on Form 10-Q includes “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. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995. These forward-looking statements are based on assumptions which we believe are reasonable based on current expectations and projections about future events and industry conditions and trends affecting our business. However, whether actual results and developments will conform to our expectations and predictions is subject to a number of risks and uncertainties that, among other things, could cause actual results to differ materially from those contained in the forward-looking statements, including without limitation, the risk factors described in Item 1A of Part I of our 2025 Annual Report on Form 10-K, Part II, Item 1A of this Quarterly Report on Form 10-Q, and other reports that we file with the SEC from time to time, and the following:

- Our ability to obtain timely and adequate regulatory approvals and cost recovery;
- Our ability to execute our capital investment program and strategic initiatives;
- Our ability to access capital markets and successfully execute financing plans;
- The effects of inflation, interest rates, commodity prices, supply chain constraints and labor availability;
- Severe weather, wildfire, cybersecurity incidents (including risks associated with the use of artificial intelligence and evolving cyber threats), operational and other business risks;
- Changes in laws, regulations and governmental policies;
- Our ability to serve customer growth opportunities, including large-load customers and accurately forecast long-term customer demand;
- The expected timing, scope and benefits of the Google data center project in southern Wyoming, including construction, financing and operational milestones; the timing and availability of equipment and milestone payments; the receipt of required regulatory, permitting and licensing approvals; transmission availability; the availability and cost of labor, materials and financing; changes in customer development schedules, customer demand forecasts, and energy requirements; the ability to satisfy contractual conditions and performance obligations; the performance of customers, suppliers, contractors and other counterparties; and the ability to successfully develop, place into service and realize the anticipated economic and operational benefits of the project and related large-load customer opportunities; and
- The expected timing and likelihood of completion and our ability to realize the anticipated benefits of the proposed merger with NorthWestern, including the timing, receipt and terms and conditions of any required governmental and regulatory approvals of the proposed acquisition that could reduce anticipated benefits or give rise to the termination of the merger.

New factors that could cause actual results to differ materially from those described in forward-looking statements emerge from time-to-time, and it is not possible for us to predict all such factors, or the extent to which any such factor or combination of factors may cause actual results to differ from those contained in any forward-looking statement. We assume no obligation to update publicly any such forward-looking statements, whether as a result of new information, future events or otherwise.

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

(unaudited)	Three Months Ended September 30, 2026	2025	Nine Months Ended September 30, 2026	2025
	(in millions, except per share amounts)			
Revenue	$ 466.1	$ 430.2	$ 1,699.6	$ 1,674.5
Operating expenses:				
Fuel, purchased power and cost of natural gas sold	121.4	112.0	572.8	595.7
Operations and maintenance	153.4	150.8	451.9	452.2
Depreciation and amortization	76.2	71.5	226.3	210.5
Taxes other than income taxes	17.0	17.2	51.5	50.0
Total operating expenses	368.0	351.5	1,302.5	1,308.4
Operating income	98.1	78.7	397.1	366.1
Other income (expense):				
Interest expense incurred net of amounts capitalized	(51.7)	(50.6)	(157.6)	(152.2)
Interest income	1.6	1.2	3.9	2.6
Other income (expense), net	1.3	0.6	2.2	1.1
Total other (expense)	(48.8)	(48.8)	(151.5)	(148.5)
Income before income taxes	49.3	29.9	245.6	217.6
Income tax (expense)	(5.8)	(4.0)	(28.5)	(26.5)
Net income	43.5	25.9	217.1	191.1
Net income attributable to non-controlling interest	(2.5)	(1.0)	(6.9)	(4.5)
Net income available for common stock	$ 41.0	$ 24.9	$ 210.2	$ 186.6
Earnings per share of common stock:				
Earnings per share, Basic	$ 0.54	$ 0.34	$ 2.77	$ 2.58
Earnings per share, Diluted	$ 0.54	$ 0.34	$ 2.76	$ 2.58
Weighted average common shares outstanding:				
Basic	76.1	72.8	75.8	72.3
Diluted	76.4	72.9	76.1	72.4

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

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(unaudited)	Three Months Ended September 30, 2026	2025	Nine Months Ended September 30, 2026	2025
	(in millions)			
Net income	$ 43.5	$ 25.9	$ 217.1	$ 191.1
Other comprehensive income (loss), net of tax:				
Reclassification of benefit plan liability	—	—	0.2	0.1
Derivative instruments designated as cash flow hedges:				
Reclassification of settled/amortized interest rate swaps	0.4	0.5	1.4	1.6
Unrealized (loss) on commodity derivatives	(0.3)	(1.3)	(0.2)	(1.5)
Reclassification of settled commodity derivatives	—	—	1.8	0.4
Other comprehensive income (loss), net of tax	0.1	(0.8)	3.2	0.6
Comprehensive income	43.6	25.1	220.3	191.7
Less: comprehensive income attributable to non-controlling interest	(2.5)	(1.0)	(6.9)	(4.5)
Comprehensive income available for common stock	$ 41.1	$ 24.1	$ 213.4	$ 187.2

See Note 9 for additional disclosures.

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

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS

(unaudited)

	As of	
	September 30, 2026	**December 31, 2025**
	(in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 18.2	$ 182.8
Restricted cash and equivalents	8.3	7.6
Accounts receivable, net	256.8	389.0
Materials, supplies and fuel	186.3	172.4
Income tax receivable, net	23.0	23.3
Regulatory assets, current	125.8	139.7
Other current assets	75.9	81.1
Total current assets	694.3	995.9
Property, plant and equipment	11,055.5	10,344.9
Less: accumulated depreciation	(2,273.3)	(2,110.7)
Total property, plant and equipment, net	8,782.2	8,234.2
Other assets:		
Goodwill	1,299.5	1,299.5
Intangible assets, net	5.4	6.4
Regulatory assets, non-current	266.7	255.0
Other assets, non-current	95.6	78.8
Total other assets, non-current	1,667.2	1,639.7
TOTAL ASSETS	$ 11,143.7	$ 10,869.8

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

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS
(Continued)

(unaudited)

	As of	
	September 30, 2026	**December 31, 2025**
	(in millions, except par value and shares)	
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 198.4	$ 311.7
Accrued liabilities	305.3	322.6
Refundable advances for construction	398.8	—
Derivative liabilities, current	3.5	5.8
Regulatory liabilities, current	97.3	99.9
Notes payable	61.5	—
Current maturities of long-term debt	410.0	—
Total current liabilities	1,474.8	740.0
Long-term debt, net of current maturities	3,995.3	4,701.1
Deferred credits and other liabilities:		
Deferred income tax liabilities, net	751.9	697.9
Regulatory liabilities, non-current	498.3	488.3
Benefit plan liabilities	121.0	123.4
Other deferred credits and other liabilities	270.0	213.4
Total deferred credits and other liabilities	1,641.2	1,523.0
Commitments, contingencies and guarantees (Note 3)		
Equity:		
Stockholders' equity -		
Common stock $1 par value; 100,000,000 shares authorized; issued 76,579,673 and 75,520,234 shares, respectively	76.6	75.5
Additional paid-in capital	2,493.3	2,417.5
Retained earnings	1,392.9	1,342.9
Treasury stock, at cost - 54,409 and 43,167 shares, respectively	(3.5)	(2.6)
Accumulated other comprehensive (loss)	(6.5)	(9.7)
Total stockholders' equity	3,952.8	3,823.6
Non-controlling interest	79.6	82.1
Total equity	4,032.4	3,905.7
TOTAL LIABILITIES AND TOTAL EQUITY	$ 11,143.7	$ 10,869.8

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

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)	Nine Months Ended September 30, 2026	2025
	(in millions)	
Operating activities:		
Net income	$ 217.1	$ 191.1
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	226.3	210.5
Deferred financing cost amortization	7.0	7.2
Stock compensation	9.5	8.0
Deferred income taxes	39.2	40.6
Employee benefit plans	7.0	8.9
Other adjustments	11.6	2.8
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	(12.7)	(19.0)
Accounts receivable and other current assets	139.7	90.8
Accounts payable and other current liabilities	(80.5)	(70.4)
Regulatory assets	1.7	47.1
Other operating activities, net	(23.3)	(12.3)
Net cash provided by operating activities	542.6	505.3
Investing activities:		
Property, plant and equipment additions	(756.0)	(550.2)
Other investing activities	(7.7)	(6.2)
Net cash (used in) investing activities	(763.7)	(556.4)
Financing activities:		
Dividends paid on common stock	(160.2)	(146.8)
Issuance of common stock, net	68.9	219.2
Net borrowings (payments) of Revolving Credit Facility and CP Program	61.5	(7.8)
Long-term debt - repayments	(300.0)	—
Distributions to non-controlling interests	(9.3)	(5.2)
Proceeds from refundable advances for construction	398.8	—
Other financing activities	(2.5)	(2.6)
Net cash provided by financing activities	57.2	56.8
Net change in cash, restricted cash and cash equivalents	(163.9)	5.7
Cash, restricted cash, and cash equivalents beginning of period	190.4	23.4
Cash, restricted cash, and cash equivalents end of period	$ 26.5	$ 29.1
Supplemental cash flow information:		
Cash (paid) received during the period:		
Interest, net of amounts capitalized	$ (150.3)	$ (145.4)
Income taxes, net of transferred tax credits (Note 11)	12.2	12.9
Non-cash investing and financing activities:		
Accrued property, plant, and equipment purchases	98.7	121.7

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

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY

(unaudited)	Common Stock		Treasury Stock						
	Shares	Value	Shares	Value	Additional Paid in Capital	Retained Earnings	AOCI	Non-controlling Interest	Total
	(in millions except share amounts)								
December 31, 2025	75,520,234	$ 75.5	43,167	$ (2.6)	$ 2,417.5	$ 1,342.9	$ (9.7)	$ 82.1	$ 3,905.7
Net income	—	—	—	—	—	131.0	—	2.1	133.1
Other comprehensive income, net of tax	—	—	—	—	—	—	2.2	—	2.2
Dividends on common stock ($0.703 per share)	—	—	—	—	—	(53.1)	—	—	(53.1)
Share-based compensation	93,064	0.1	14,338	(1.1)	1.8	—	—	—	0.8
Issuance of common stock	560,966	0.6	—	—	40.6	—	—	—	41.2
Issuance costs	—	—	—	—	(0.5)	—	—	—	(0.5)
Distributions to non-controlling interest	—	—	—	—	—	—	—	(2.5)	(2.5)
March 31, 2026	76,174,264	$ 76.2	57,505	$ (3.7)	$ 2,459.4	$ 1,420.8	$ (7.5)	$ 81.7	$ 4,026.9
Net income	—	—	—	—	—	38.2	—	2.2	40.4
Other comprehensive income, net of tax	—	—	—	—	—	—	0.9	—	0.9
Dividends on common stock ($0.703 per share)	—	—	—	—	—	(53.5)	—	—	(53.5)
Share-based compensation	13,906	—	3,604	(0.3)	3.5	—	—	—	3.2
Issuance of common stock	129,275	0.1	—	—	9.4	—	—	—	9.5
Issuance costs	—	—	—	—	(0.1)	—	—	—	(0.1)
Distributions to non-controlling interest	—	—	—	—	—	—	—	(3.6)	(3.6)
June 30, 2026	76,317,445	$ 76.3	61,109	$ (4.0)	$ 2,472.2	$ 1,405.5	$ (6.6)	$ 80.3	$ 4,023.7
Net income	—	—	—	—	—	41.0	—	2.5	43.5
Other comprehensive income, net of tax	—	—	—	—	—	—	0.1	—	0.1
Dividends on common stock ($0.703 per share)	—	—	—	—	—	(53.6)	—	—	(53.6)
Share-based compensation	9	—	(6,700)	0.5	2.6	—	—	—	3.1
Issuance of common stock	262,219	0.3	—	—	18.9	—	—	—	19.2
Issuance costs	—	—	—	—	(0.4)	—	—	—	(0.4)
Distributions to non-controlling interest	—	—	—	—	—	—	—	(3.2)	(3.2)
September 30, 2026	76,579,673	$ 76.6	54,409	$ (3.5)	$ 2,493.3	$ 1,392.9	$ (6.5)	$ 79.6	$ 4,032.4

(unaudited)	Common Stock		Treasury Stock						
	Shares	Value	Shares	Value	Additional Paid in Capital	Retained Earnings	AOCI	Non-controlling Interest	Total
					(in millions except share amounts)				
December 31, 2024	71,676,756	$ 71.7	56,608	$ (3.3)	$ 2,193.4	$ 1,249.1	$ (9.4)	$ 83.7	$ 3,585.2
Net income	—	—	—	—	—	134.3	—	2.1	136.4
Other comprehensive income, net of tax	—	—	—	—	—	—	1.0	—	1.0
Dividends on common stock ($0.676 per share)	—	—	—	—	—	(48.6)	—	—	(48.6)
Share-based compensation	103,995	0.1	(22,488)	1.3	(0.1)	—	—	—	1.3
Issuance of common stock	763,481	0.7	—	—	45.4	—	—	—	46.1
Issuance costs	—	—	—	—	(0.5)	—	—	—	(0.5)
Distributions to non-controlling interest	—	—	—	—	—	—	—	(3.8)	(3.8)
March 31, 2025	72,544,232	$ 72.5	34,120	$ (2.0)	$ 2,238.2	$ 1,334.8	$ (8.4)	$ 82.0	$ 3,717.1
Net income	—	—	—	—	—	27.5	—	1.3	28.8
Other comprehensive income, net of tax	—	—	—	—	—	—	0.4	—	0.4
Dividends on common stock ($0.676 per share)	—	—	—	—	—	(49.0)	—	—	(49.0)
Share-based compensation	19,159	0.1	13,827	(0.8)	3.4	—	—	—	2.7
Issuance of common stock	339,285	0.3	—	—	19.4	—	—	—	19.7
Issuance costs	—	—	—	—	(0.3)	—	—	—	(0.3)
June 30, 2025	72,902,676	$ 72.9	47,947	$ (2.8)	$ 2,260.7	$ 1,313.3	$ (8.0)	$ 83.3	$ 3,719.4
Net income	—	—	—	—	—	24.9	—	1.0	25.9
Other comprehensive income, net of tax	—	—	—	—	—	—	(0.8)	—	(0.8)
Dividends on common stock ($0.676 per share)	—	—	—	—	—	(49.2)	—	—	(49.2)
Share-based compensation	10	—	(1,504)	0.1	2.7	—	—	—	2.8
Issuance of common stock	2,617,539	2.6	—	—	153.0	—	—	—	155.6
Issuance costs	—	—	—	—	(1.4)	—	—	—	(1.4)
Distributions to non-controlling interest	—	—	—	—	—	—	—	(1.4)	(1.4)
September 30, 2025	75,520,225	$ 75.5	46,443	$ (2.7)	$ 2,415.0	$ 1,289.0	$ (8.8)	$ 82.9	$ 3,850.9

BLACK HILLS CORPORATION

Condensed Notes to Consolidated Financial Statements
(unaudited)
(Reference is made to Notes to Consolidated Financial Statements
included in the Company's 2025 Annual Report on Form 10-K)

(1) Management's Statement

The unaudited Consolidated Financial Statements included herein have been prepared by Black Hills Corporation (together with our subsidiaries the "Company", "us", "we", or "our"), pursuant to the rules and regulations of the SEC. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted pursuant to such rules and regulations; however, we believe that the footnotes adequately disclose the information presented. These Consolidated Financial Statements should be read in conjunction with the consolidated financial statements and the notes included in our 2025 Annual Report on Form 10-K.

Use of Estimates and Basis of Presentation

The information furnished in the accompanying Consolidated Financial Statements reflects certain estimates required and all adjustments, including accruals, which are, in the opinion of management, necessary for a fair presentation of the September 30, 2026, December 31, 2025, and September 30, 2025, financial information. Certain lines of business in which we operate are highly seasonal and our interim results of operations are not necessarily indicative of the results of operations to be expected for an entire year.

Recently Issued Accounting Standards

Disaggregation of Income Statement Expenses, ASU 2024-03

In November 2024, the FASB issued ASU 2024-03, *Income Statement - Reporting Comprehensive Income - Expense Disaggregation Disclosures*, and in January 2025, the FASB issued ASU 2025-01, *Income Statement - Reporting Comprehensive Income - Expense Disaggregation Disclosures: Clarifying the Effective Date.* ASU 2024-03 requires public entities to disclose, in the notes to financial statements, certain costs and expenses, such as purchases of inventory, employee compensation, and costs related to depreciation and amortization. ASU 2024-03, as clarified by ASU 2025-01, is effective for our Annual Report on Form 10-K for the fiscal year ended December 31, 2027, and subsequent interim periods, with early adoption permitted. We are currently evaluating the impact of these standards on our consolidated financial statement disclosures.

Targeted Improvements to the Accounting for Internal-Use Software, ASU 2025-06

In September 2025, the FASB issued ASU 2025-06, Targeted Improvements to the Accounting for Internal-Use Software, which amends the accounting guidance for internal-use software under ASC 350-40. The amendments are intended to modernize the recognition and capitalization framework to better reflect current software development practices, particularly agile methodologies. ASU 2025-06 is effective for fiscal years beginning after December 15, 2027, including interim periods within those fiscal years. Early adoption is permitted. We are currently evaluating the impact of ASU 2025-06 on our consolidated financial statements and related disclosures.

(2) Regulatory Matters

We had the following regulatory assets and liabilities:

	As of September 30, 2026	As of December 31, 2025
	(in millions)	
Regulatory assets		
Winter Storm Uri	$ 16.8	$ 50.7
Deferred energy and fuel cost adjustments	95.4	83.3
Deferred gas cost adjustments	18.1	10.2
Gas price derivatives	3.1	4.6
Deferred taxes on AFUDC	11.5	10.6
Employee benefit plans and related deferred taxes	85.1	87.4
Environmental	13.3	13.1
Loss on reacquired debt	12.9	14.1
Deferred taxes on flow through accounting	100.3	94.8
Other regulatory assets	36.0	25.9
Total regulatory assets	392.5	394.7
Less current regulatory assets	(125.8)	(139.7)
Regulatory assets, non-current	$ 266.7	$ 255.0
Regulatory liabilities		
Deferred energy and fuel cost adjustments	$ 19.0	$ 12.3
Deferred gas cost adjustments	24.7	51.5
Employee benefit plan costs and related deferred taxes	35.5	36.2
Cost of removal	230.4	216.5
Excess deferred income taxes	223.5	230.3
Colorado renewable energy	40.0	33.2
Other regulatory liabilities	22.5	8.2
Total regulatory liabilities	595.6	588.2
Less current regulatory liabilities	(97.3)	(99.9)
Regulatory liabilities, non-current	$ 498.3	$ 488.3

Recent Rate Review Activity

Arkansas Gas

On December 5, 2025, Arkansas Gas filed a rate review with the APSC seeking recovery of infrastructure investments in its natural gas pipeline system. On October 12, 2026, Arkansas Gas received final approval from the APSC for approval of new rates. The new rates are expected to generate $17.9 million in new annual revenue with a capital structure of 47.5% equity and 52.5% debt and a return on equity of 9.8%. New rates were effective October 12, 2026.

Colorado Electric

On June 12, 2026, Colorado Electric filed a rate review with the CPUC seeking recovery of infrastructure and operational costs in its electric service. The rate review requested $26.7 million in new annual revenue with a capital structure of 51% equity and 49% debt and a return on equity of 10.5%. The request seeks to implement new rates in the first quarter of 2027.

Kansas Gas

On February 3, 2025, Kansas Gas filed a rate review with the KCC seeking recovery of infrastructure investments and increased operations and maintenance costs driven by inflation and operational needs to serve customers. On July 24, 2025, Kansas Gas received final approval from the KCC for a Black-box Settlement agreement for a general rate increase expected to generate $10.8 million in new annual revenue and shift $4.4 million of GSRS rider revenue to base rates. New rates were enacted on August 1, 2025. The settlement also included approval for Kansas Gas to file an abbreviated case in first quarter of 2026 that includes the addition of capital placed in service through December 31, 2025. On March 2, 2026, Kansas Gas filed the abbreviated case, which was limited in scope and requested increases in base rate revenues of $2.4 million. On June 25, 2026, the KCC approved the abbreviated request with new rates effective July 1, 2026.

Nebraska Gas

On May 1, 2025, Nebraska Gas filed a rate review with the NPSC seeking recovery of infrastructure investments and increased operations and maintenance costs driven by inflation and operational needs to serve customers. On December 9, 2025, Nebraska Gas received final approval from the NPSC for a settlement agreement for a general rate increase. The settlement is expected to generate $23.9 million in new annual revenue with a capital structure of 51% equity and 49% debt and a return on equity of 9.85%. The settlement also includes renewal of Nebraska Gas' SSIR for five years and the development of a two-year pilot program for a weather normalization adjustment rider. New rates were enacted on January 1, 2026, which replaced interim rates effective in August 2025. Nebraska Gas customers were entitled to a $4.7 million refund due to the interim rate increase exceeding the final approved rate increase, which was retroactive to August 2025. These amounts were refunded to customers as a one-time bill credit during the second quarter of 2026.

South Dakota Electric

On February 19, 2026, South Dakota Electric filed a rate review with the SDPUC seeking recovery of infrastructure investments and increased operations and maintenance costs driven by inflation and operational needs to serve customers since its last rate review in 2014. On November 4, 2026, South Dakota Electric received approval from the SDPUC for a settlement agreement for a general rate increase. The Black-box settlement is expected to generate $27.4 million in new annual revenue based on a weighted average cost of capital of 7.58%. The settlement also includes a 4-year moratorium period, in which South Dakota Electric will not increase base rates, absent an extraordinary event, until August 2030. The moratorium excludes South Dakota Electric's additional regulatory mechanisms such as the ECA, TFA, EIA and the pending PIPR. New rates are effective in December 2026, and will replace interim rates which were effective in August 2026.

On March 18, 2026, South Dakota Electric filed a rate review with the WPSC seeking recovery of infrastructure investments and increased operations and maintenance costs driven by inflation and operational needs to serve customers since its last rate review in 2014. On October 7, 2026, South Dakota Electric received approval from the WPSC for a settlement agreement for a general rate increase. The settlement is expected to generate $4.0 million in new annual revenue with a capital structure of 53% equity and 47% debt and a return on equity of 9.60%. New rates are effective December 1, 2026.

(3) Commitments, Contingencies and Guarantees

Google Data Center Agreements

In September 2026, the Company entered into long-term agreements with Google and other third-party partners to serve a planned data center project to be constructed in Cheyenne, Wyoming. The negotiated agreements include a LPCS agreement and a generation facilities agreement, both of which extend through December 2048. The project is contracted to be served through a total resource mix of 2.7 GW, including reserve margins, and is expected to begin taking energy service in late 2027 and ramp to the data center's projected peak load by the end of 2030. We expect to provide up to 590 MW of grid-connected energy service through company-owned generation and market energy. In addition, we expect to manage the output of approximately 2.1 GW of third-party contracted resources through a privately managed microgrid under the Company's LPCS tariff.

To provide 590 MW of grid-connected service, the Company expects to construct 564 MW of new company-owned natural gas-fired generation between 2027 and 2029 through a non-regulated affiliate. In connection with the development of the project, the Company previously disclosed customer-funded refundable advances received pursuant to the parties' generation reservation agreement to support procurement of long-lead generation equipment. During the third quarter of 2026, the parties amended the generation reservation agreement to increase the permitted advances to $398.8 million and extend the repayment date to June 30, 2027. As of September 30, 2026, the Company had recorded $398.8 million of refundable customer advances as a liability on its Consolidated Balance Sheets and expects to repay such advances by their June 30, 2027 maturity date.

Deborah Ferrari et al. v. Colorado Electric, Case No. 2024CV31889 (District Court for the City and County of Denver, Colorado)

During the year ended December 31, 2025, Colorado Electric settled a legal matter involving an auto accident. As part of the settlement, Colorado Electric recognized a legal liability of $20 million, which was paid in the first quarter of 2026. In connection with this matter, Colorado Electric also recognized a loss recovery receivable of $20 million under its insurance coverage, which was received in the first quarter of 2026. We do not expect additional material losses related to this matter.

Power Purchase Agreement for Clean Energy Plan

On February 18, 2026, Colorado Electric executed a PPA with Honors Energy, LLC to purchase up to 200 MW of solar energy upon construction of a new renewable generation facility, which is expected to be completed by mid-2029. The agreement will expire 15 years after construction completion. The solar energy from this PPA will be used to support Colorado Electric's Clean Energy Plan.

(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 three and nine months ended September 30, 2026, and 2025. Sales tax and other similar taxes are excluded from revenues.

Three Months Ended September 30, 2026	Electric Utilities	Gas Utilities	Inter-segment Eliminations	Total
Customer types:		(in millions)		
Retail	$ 227.8	$ 127.9	$ —	$ 355.7
Transportation	—	47.2	(0.1)	47.1
Wholesale	6.4	—	—	6.4
Market - off-system sales	9.7	—	—	9.7
Transmission	20.8	0.2	—	21.0
Other revenues	14.3	10.6	(3.9)	21.0
Revenue from contracts with customers	$ 279.0	$ 185.9	$ (4.0)	$ 460.9
Alternative revenue and other	1.4	3.8	—	5.2
Total revenues	$ 280.4	$ 189.7	$ (4.0)	$ 466.1
Timing of revenue recognition:				
Services transferred at a point in time	$ 9.2	$ —	$ —	$ 9.2
Services transferred over time	269.8	185.9	(4.0)	451.7
Revenue from contracts with customers	$ 279.0	$ 185.9	$ (4.0)	$ 460.9

Three Months Ended September 30, 2025	Electric Utilities	Gas Utilities	Inter-segment Eliminations	Total
Customer types:		(in millions)		
Retail	$ 201.3	$ 128.6	$ —	$ 329.9
Transportation	—	43.6	(0.1)	43.5
Wholesale	5.5	—	—	5.5
Market - off-system sales	16.3	—	—	16.3
Transmission	11.1	0.1	—	11.2
Other revenues	14.6	10.2	(3.8)	21.0
Revenue from contracts with customers	$ 248.8	$ 182.5	$ (3.9)	$ 427.4
Alternative revenue and other	0.9	1.9	—	2.8
Total revenues	$ 249.7	$ 184.4	$ (3.9)	$ 430.2
Timing of revenue recognition:				
Services transferred at a point in time	$ 8.8	$ —	$ —	$ 8.8
Services transferred over time	240.0	182.5	(3.9)	418.6
Revenue from contracts with customers	$ 248.8	$ 182.5	$ (3.9)	$ 427.4

Nine Months Ended September 30, 2026	Electric Utilities	Gas Utilities	Inter-segment Eliminations	Total
Customer types:		(in millions)		
Retail	$ 609.2	$ 751.7	$ —	$ 1,360.9
Transportation	—	146.5	(0.3)	146.2
Wholesale	17.7	—	—	17.7
Market - off-system sales	23.0	—	—	23.0
Transmission	50.3	0.6	—	50.9
Other revenues	43.5	30.9	(11.7)	62.7
Revenue from contracts with customers	$ 743.7	$ 929.7	$ (12.0)	$ 1,661.4
Alternative revenue and other	4.6	33.6	—	38.2
Total revenues	$ 748.3	$ 963.3	$ (12.0)	$ 1,699.6
Timing of revenue recognition:				
Services transferred at a point in time	$ 26.1	$ —	$ —	$ 26.1
Services transferred over time	717.6	929.7	(12.0)	1,635.3
Revenue from contracts with customers	$ 743.7	$ 929.7	$ (12.0)	$ 1,661.4

Nine Months Ended September 30, 2025	Electric Utilities	Gas Utilities	Inter-segment Eliminations	Total
Customer types:		(in millions)		
Retail	$ 570.6	$ 797.0	$ —	$ 1,367.6
Transportation	—	143.4	(0.3)	143.1
Wholesale	16.9	—	—	16.9
Market - off-system sales	38.3	0.1	—	38.4
Transmission	33.3	0.3	—	33.6
Other revenues	43.9	31.5	(11.4)	64.0
Revenue from contracts with customers	$ 703.0	$ 972.3	$ (11.7)	$ 1,663.6
Alternative revenue and other	3.3	7.6	—	10.9
Total revenues	$ 706.3	$ 979.9	$ (11.7)	$ 1,674.5
Timing of revenue recognition:				
Services transferred at a point in time	$ 25.9	$ —	$ —	$ 25.9
Services transferred over time	677.1	972.3	(11.7)	1,637.7
Revenue from contracts with customers	$ 703.0	$ 972.3	$ (11.7)	$ 1,663.6

(5) 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, subordinated 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 June 16, 2023 (Registration No. 333-272739), we filed a new shelf registration statement on Form S-3 on May 19, 2026, (Registration No. 333-296010).

Short-term Debt

Refundable Advances for Construction

See Note 3 for discussion of our Refundable advances for construction under our generation reservation agreement.

Revolving Credit Facility and CP Program

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 as of:

	September 30, 2026	December 31, 2025
	(dollars in millions)	
Amount outstanding	$ 61.5	$ —
Letters of credit [(a)]	3.7	3.2
Available capacity	$ 684.8	$ 746.8
Weighted average interest rates	4.09%	N/A

(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 was as follows:

	Nine Months Ended September 30, 2026	2025
	(dollars in millions)	
Maximum amount outstanding (based on daily outstanding balances)	$ 338.0	$ 263.6
Average amount outstanding (based on daily outstanding balances)	118.9	115.9
Weighted average interest rates	3.90%	4.55%

Long-term Debt

On October 2, 2025, we completed a public debt offering of $450 million, 4.55% senior unsecured notes due January 31, 2031. Proceeds from the offering, which were reduced by $4.0 million of deferred financing costs, were used to repay all $300 million principal amount outstanding of our 3.95% senior unsecured notes at their January 15, 2026, maturity date and for other general corporate purposes.

Financial Covenants

Revolving Credit Facility

We were in compliance with all of our Revolving Credit Facility covenants as of September 30, 2026. 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 September 30, 2026, our Consolidated Indebtedness to Capitalization Ratio was 0.53 to 1.00. Consolidated Indebtedness, as defined under the terms of our Revolving Credit Facility, does not include the $398.8 million of Refundable advances for construction as of September 30, 2026, discussed in Note 3.

Wyoming Electric

Wyoming Electric was in compliance with all covenants within its financing agreements as of September 30, 2026. Wyoming Electric is required to maintain a debt to capitalization ratio of no more than 0.60 to 1.00. As of September 30, 2026, Wyoming Electric's debt to capitalization ratio was 0.48 to 1.00. Debt, as defined under the terms of Wyoming Electric's financing agreements, does not include the $398.8 million of Refundable advances for construction as of September 30, 2026, discussed in Note 3.

Equity

ATM

ATM activity was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	**2025**	**2026**	**2025**
June 16, 2023 ATM Program	(in millions, except Average price per share amounts)			
Proceeds, (net of issuance costs of $0.0, $0.0, $0.0, and $(0.5), respectively)	$ —	$ —	$ —	$ 45.7
Number of shares issued	—	—	—	0.8
May 8, 2025 ATM Program				
Proceeds, (net of issuance costs of $(0.4), $(1.3), $(1.0), and $(1.5), respectively)	$ 18.9	$ 154.3	$ 68.9	$ 173.9
Number of shares issued	0.3	2.6	1.0	2.9
Total activity under both ATM Programs				
Proceeds, (net of issuance costs of $(0.4), $(1.3), $(1.0), and $(2.0), respectively)	$ 18.9	$ 154.3	$ 68.9	$ 219.6
Number of shares issued	0.3	2.6	1.0	3.7
Average price per share	$ 73.13	$ 59.47	$ 73.42	$ 59.56

(6) Earnings Per Share

A reconciliation of share amounts used to compute earnings per share in the accompanying Consolidated Statements of Income was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
	(in millions, except per share amounts)			
Net income available for common stock	$ 41.0	$ 24.9	$ 210.2	$ 186.6
Weighted average shares - basic	76.1	72.8	75.8	72.3
Dilutive effect of equity compensation	0.3	0.1	0.3	0.1
Weighted average shares - diluted	76.4	72.9	76.1	72.4
Net income available for common stock, per share - Diluted	$ 0.54	$ 0.34	$ 2.76	$ 2.58

Anti-dilutive shares excluded from the diluted earnings per share computation were not material for the three and nine months ended September 30, 2026, and 2025.

(7) 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 weather, geopolitical events, pandemics, market speculation, imposition of new tariffs, 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.

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 customers' 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.

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 are detailed below and in Note 8.

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 the state regulatory commission guidelines. When the related costs are recovered through our rates, the hedging activity is recognized in the Consolidated Statements of Income.

Through Black Hills Energy Services, our non-regulated natural gas commodity supplier, we buy, sell, and deliver natural gas in Nebraska and Wyoming 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 through September 2028. 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 electric and natural gas derivative commodity instruments held at our Utilities are composed of both long and short positions. We had the following net long and (short) positions as of:

	September 30, 2026		December 31, 2025	
	Notional Amounts (MMBtus)	Maximum Term (months) [a]	Notional Amounts (MMBtus)	Maximum Term (months) [a]
Natural gas futures purchased	1,740,000	6	620,000	3
Natural gas options purchased, net	7,660,000	6	2,750,000	3
Natural gas basis swaps purchased	1,740,000	6	1,040,000	3
Natural gas over-the-counter swaps, net [b]	5,670,000	23	3,430,000	23
Natural gas physical contracts, net [c]	21,178,995	6	14,285,200	10

(a) Term reflects the maximum forward period hedged.
(b) As of September 30, 2026, 1,281,000 MMBtus of natural gas over-the-counter swaps purchases were designated as cash flow hedges.
(c) Volumes exclude contracts that qualify for the normal purchases and normal sales exception under 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 September 30, 2026, the Company had $0.7 million related to such provisions, which would be included in Other current assets on the Consolidated Balance Sheets.

Derivatives by Balance Sheet Classification

The following table presents the fair value and balance sheet classification of our derivative instruments as of:

	Balance Sheet Location	September 30, 2026	December 31, 2025
		(in millions)	
Derivatives designated as hedges:			
Liability derivative instruments:			
Current commodity derivatives	Derivative liabilities, current	$ (0.7)	$ (2.8)
Total derivatives designated as hedges		$ (0.7)	$ (2.8)
Derivatives not designated as hedges:			
Liability derivative instruments:			
Current commodity derivatives	Derivative liabilities, current	$ (2.8)	$ (3.0)
Total derivatives not designated as hedges		$ (2.8)	$ (3.0)

Derivatives Designated as Hedge Instruments

The impact of cash flow hedges on our Consolidated Statements of Comprehensive Income and Consolidated Statements of Income are presented below for the three and nine months ended September 30, 2026, and 2025. 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	Three Months Ended September 30, 2026	2025	Income Statement Location	Three Months Ended September 30, 2026	2025
	Amount of Gain/(Loss) Recognized in OCI			Amount of Gain/(Loss) Reclassified from AOCI into Income	
	(in millions)			(in millions)	
Interest rate swaps	$ 0.5	$ 0.7	Interest expense	$ (0.5)	$ (0.7)
Commodity derivatives	(0.4)	(1.6)	Fuel, purchased power, and cost of natural gas sold	—	(0.1)
Total	$ 0.1	$ (0.9)		$ (0.5)	$ (0.8)

Derivatives in Cash Flow Hedging Relationships	Nine Months Ended September 30, 2026	2025	Income Statement Location	Nine Months Ended September 30, 2026	2025
	Amount of Gain/(Loss) Recognized in OCI			Amount of Gain/(Loss) Reclassified from AOCI into Income	
	(in millions)			(in millions)	
Interest rate swaps	$ 1.8	$ 2.1	Interest expense	$ (1.8)	$ (2.1)
Commodity derivatives	2.0	(1.3)	Fuel, purchased power, and cost of natural gas sold	(2.3)	(0.5)
Total	$ 3.8	$ 0.8		$ (4.1)	$ (2.6)

As of September 30, 2026, $1.0 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 three and nine months ended September 30, 2026, and 2025. 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 profit or loss 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	Three Months Ended September 30, 2026	2025
		Amount of Gain/(Loss) on Derivatives Recognized in Income	
		(in millions)	
Commodity derivatives	Fuel, purchased power, and cost of natural gas sold	$ (0.6)	$ (0.6)
		$ (0.6)	$ (0.6)

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Nine Months Ended September 30, 2026	2025
		Amount of Gain/(Loss) on Derivatives Recognized in Income	
		(in millions)	
Commodity derivatives	Fuel, purchased power, and cost of natural gas sold	$ —	$ —
		$ —	$ —

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 our Regulatory asset accounts related to these financial instruments were $3.1 million and $4.6 million as of September 30, 2026, and December 31, 2025, respectively.

(8) Fair Value Measurements

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.

Recurring Fair Value Measurements

Derivatives

The commodity contracts for our Utilities segments 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 wholesale electric energy and natural gas contracts. 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. For additional information, see Note 1 of our Notes to the Consolidated Financial Statements in our 2025 Annual Report on Form 10-K.

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 September 30, 2026				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting [(a)]	Total
			(in millions)		
Assets:					
Commodity derivatives - Gas Utilities	$ —	$ 4.6	$ —	$ (4.6)	$ —
Total	$ —	$ 4.6	$ —	$ (4.6)	$ —
Liabilities:					
Commodity derivatives - Gas Utilities	$ —	$ 5.6	$ —	$ (2.1)	$ 3.5
Total	$ —	$ 5.6	$ —	$ (2.1)	$ 3.5

(a) As of September 30, 2026, $4.6 million of our commodity derivative assets and $2.1 million of our commodity derivative liabilities, as well as related gross collateral amounts, were subject to master netting agreements.

	As of December 31, 2025				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting [(a)]	Total
			(in millions)		
Assets:					
Commodity derivatives - Gas Utilities	$ —	$ 2.0	$ —	$ (2.0)	$ —
Total	$ —	$ 2.0	$ —	$ (2.0)	$ —
Liabilities:					
Commodity derivatives - Gas Utilities	$ —	$ 8.8	$ —	$ (3.0)	$ 5.8
Total	$ —	$ 8.8	$ —	$ (3.0)	$ 5.8

(a) As of December 31, 2025, $2.0 million of our commodity derivative assets and $3.0 million of our commodity derivative liabilities, as well as related gross collateral amounts, were subject to master netting agreements.

Pension and Postretirement Plan Assets

The fair value of our pension and postretirement plan assets is presented in Note 13 to the Consolidated Financial Statements included in our 2025 Annual Report on Form 10-K.

Captive Insurance Cell Investments

We have investments in the Captive that may be used to pay insurance losses in the event of certain insured loss events. The Captive may hold investment assets in cash, cash equivalents, and equity and fixed income instruments. These investments are restricted for insured loss events. Additional information regarding the Captive is presented in Note 12 to the Consolidated Financial Statements included in our 2025 Annual Report on Form 10-K.

Other Fair Value Measures

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 as of:

	September 30, 2026		December 31, 2025	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Long-term debt, including current maturities [(a)]	$ 4,405.3	$ 4,096.9	$ 4,701.1	$ 4,639.0

(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.

(9) 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:

		Amount Reclassified from AOCI			
		Three Months Ended September 30,		Nine Months Ended September 30,	
	Location on the Consolidated Statements of Income	2026	2025	2026	2025
		(in millions)			
Gains and (losses) on cash flow hedges:					
Interest rate swaps	Interest expense	$ (0.5)	$ (0.7)	$ (1.8)	$ (2.1)
Commodity contracts	Fuel, purchased power, and cost of natural gas sold	—	(0.1)	(2.3)	(0.5)
		$ (0.5)	$ (0.8)	$ (4.1)	$ (2.6)
Income tax	Income tax (expense) benefit	0.1	0.2	0.9	0.6
Total reclassification adjustments related to cash flow hedges, net of tax		$ (0.4)	$ (0.6)	$ (3.2)	$ (2.0)
Amortization of components of defined benefit plans:					
Actuarial (loss)	Operations and maintenance	—	—	(0.2)	(0.1)
Total reclassification adjustments related to defined benefit plans, net of tax		$ —	$ —	$ (0.2)	$ (0.1)
Total reclassifications		$ (0.4)	$ (0.6)	$ (3.4)	$ (2.1)

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

	Derivatives Designated as Cash Flow Hedges			
	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
	(in millions)			
As of December 31, 2025	$ (1.6)	$ (2.2)	$ (5.9)	$ (9.7)
Other comprehensive income (loss) before reclassifications	—	(0.2)	—	(0.2)
Amounts reclassified from AOCI	1.4	1.8	0.2	3.4
As of September 30, 2026	$ (0.2)	$ (0.6)	$ (5.7)	$ (6.5)

	Derivatives Designated as Cash Flow Hedges			
	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
		(in millions)		
As of December 31, 2024	$ (3.8)	$ (0.3)	$ (5.3)	$ (9.4)
Other comprehensive income (loss) before reclassifications	—	(1.5)	—	(1.5)
Amounts reclassified from AOCI	1.6	0.4	0.1	2.1
As of September 30, 2025	$ (2.2)	$ (1.4)	$ (5.2)	$ (8.8)

(10) Employee Benefit Plans

Components of Net Periodic Expense

The components of net periodic expense were as follows:

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plan	
Three Months Ended September 30,	2026	2025	2026	2025	2026	2025
			(in millions)			
Service cost	$ 0.4	$ 0.4	$ 0.1	$ 1.2	$ 0.4	$ 0.4
Interest cost	3.6	4.0	0.3	0.3	0.5	0.6
Expected return on plan assets	(4.2)	(4.2)	—	—	(0.1)	(0.1)
Net amortization of prior service costs	—	—	—	—	0.1	0.1
Recognized net actuarial loss	0.6	0.5	—	—	—	—
Net periodic expense	$ 0.4	$ 0.7	$ 0.4	$ 1.5	$ 0.9	$ 1.0

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plan	
Nine Months Ended September 30,	2026	2025	2026	2025	2026	2025
			(in millions)			
Service cost	$ 1.2	$ 1.3	$ 2.3	$ 2.8	$ 1.1	$ 1.1
Interest cost	11.0	12.0	0.9	1.1	1.6	1.8
Expected return on plan assets	(12.7)	(12.7)	—	—	(0.2)	(0.2)
Net amortization of prior service costs	(0.1)	(0.1)	—	—	0.1	0.2
Recognized net actuarial loss	1.8	1.6	—	—	—	—
Net periodic expense	$ 1.2	$ 2.1	$ 3.2	$ 3.9	$ 2.6	$ 2.9

Plan Contributions

Contributions made in the first nine months of 2026 and additional contributions anticipated for the remainder of 2026 are as follows:

	Contributions Made Nine Months Ended September 30, 2026	Additional Contributions Anticipated for 2026
	(in millions)	
Defined Benefit Pension Plan	$ 1.6	$ —
Non-pension Defined Benefit Postretirement Healthcare Plan	3.3	1.2
Supplemental Non-qualified Defined Benefit and Defined Contribution Plans	2.1	0.7

(11) Income Taxes

Transfers of Production Tax Credits

In January 2025 and 2026, we entered into agreements with a third party to sell 2024 and 2025 generated PTCs for $16.0 million and $15.3 million, respectively. We expect to continue to explore monetization of our tax credits through third party transferability agreements.

Income Tax (Expense) and Effective Tax Rates

Three Months Ended September 30, 2026, Compared to the Three Months Ended September 30, 2025

Income tax (expense) for the three months ended September 30, 2026, was $(5.8) million compared to $(4.0) million reported for the same period in 2025. For the three months ended September 30, 2026, the effective tax rate was 11.8%, which was lower compared to 13.4% for the same period in 2025. The lower effective tax rate was primarily driven by increased current year tax benefits from federal PTCs associated with increased wind production and the non-deductibility of certain prior year costs related to the pending Merger.

Nine Months Ended September 30, 2026, Compared to the Nine Months Ended September 30, 2025

Income tax (expense) for the nine months ended September 30, 2026, was $(28.5) million compared to $(26.5) million reported for the same period in 2025. For the nine months ended September 30, 2026, the effective tax rate was 11.6%, which was lower compared to 12.2% for the same period in 2025. The lower effective tax rate was primarily driven by increased current year tax benefits from federal PTCs associated with increased wind production.

(12) Business Segment Information

We are a holding company that, through our subsidiaries, conducts our operations through the following two reportable segments: Electric Utilities and Gas Utilities. Certain unallocated corporate expenses that support our reportable segments are presented as Corporate and Other.

Our operating segments, which are equivalent to our reportable 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 consists of certain unallocated expenses for administrative activities that support our operating segments. Corporate and Other also includes our captive insurance cell, business development activities that are not part of our operating segments (such as costs related to the pending Merger), and inter-segment eliminations.

Our Chief Executive Officer, who is considered to be our CODM, sets financial performance objectives and budgets and establishes separate targets based on operating income for our Electric Utilities segment as well as our Gas Utilities segment. Our CODM assesses segment financial performance, including quarterly and annual budget-to-actual and year-over-year variances in revenues and expenses, to inform operating decisions, capital investments and cost recovery strategies. Our CODM reviews capital expenditures by operating segment rather than any individual or total asset amount.

Segment information was as follows:

	Consolidating Income Statement				
Three Months Ended September 30, 2026	**Electric Utilities**	**Gas Utilities**	**Total Reportable Segments**	**Corporate and Other**	**Total**
			(in millions)		
Revenue -					
External Customers	$ 277.9	$ 188.2	$ 466.1	$ —	$ 466.1
Inter-segment	2.5	1.5	4.0	(4.0)	—
Total revenue	280.4	189.7	470.1	(4.0)	466.1
Fuel, purchased power and cost of natural gas sold	81.8	39.7	121.5	(0.1)	121.4
Operations and maintenance [(a)] -					
Direct	36.2	39.8	76.0	(0.1)	75.9
Allocated	34.5	43.0	77.5	—	77.5
Depreciation and amortization	41.9	34.3	76.2	—	76.2
Taxes other than income taxes	9.1	7.9	17.0	—	17.0
Total operating expenses	203.5	164.7	368.2	(0.2)	368.0
Operating income (loss)	$ 76.9	$ 25.0	$ 101.9	$ (3.8)	$ 98.1
Interest expense, net					(50.1)
Other income (expense), net					1.3
Income tax (expense)					(5.8)
Net income					43.5
Net income attributable to non-controlling interest					(2.5)
Net income available for common stock					$ 41.0

	Consolidating Income Statement				
Three Months Ended September 30, 2025	**Electric Utilities**	**Gas Utilities**	**Total Reportable Segments**	**Corporate and Other**	**Total**
			(in millions)		
Revenue -					
External Customers	$ 247.3	$ 182.9	$ 430.2	$ —	$ 430.2
Inter-segment	2.4	1.5	3.9	(3.9)	—
Total revenue	249.7	184.4	434.1	(3.9)	430.2
Fuel, purchased power and cost of natural gas sold	69.8	42.3	112.1	(0.1)	112.0
Operations and maintenance [(a)] -					
Direct	36.1	38.9	75.0	0.7	75.7
Allocated	33.7	41.4	75.1	—	75.1
Depreciation and amortization	38.3	33.2	71.5	—	71.5
Taxes other than income taxes	9.4	7.8	17.2	—	17.2
Total operating expenses	187.3	163.6	350.9	0.6	351.5
Operating income	$ 62.4	$ 20.8	$ 83.2	$ (4.5)	$ 78.7
Interest expense, net					(49.4)
Other income (expense), net					0.6
Income tax (expense)					(4.0)
Net income					25.9
Net income attributable to non-controlling interest					(1.0)
Net income available for common stock					$ 24.9

Nine Months Ended September 30, 2026	Consolidating Income Statement				
	Electric Utilities	Gas Utilities	Total Reportable Segments	Corporate and Other	Total
			(in millions)		
Revenue -					
External Customers	$ 740.7	$ 958.9	$ 1,699.6	$ —	$ 1,699.6
Inter-segment	7.6	4.4	12.0	(12.0)	—
Total revenue	748.3	963.3	1,711.6	(12.0)	1,699.6
Fuel, purchased power and cost of natural gas sold	198.3	374.8	573.1	(0.3)	572.8
Operations and maintenance [(a)] -					
Direct	102.7	121.5	224.2	1.4	225.6
Allocated	99.4	126.9	226.3	—	226.3
Depreciation and amortization	123.3	103.0	226.3	—	226.3
Taxes other than income taxes	27.5	24.0	51.5	—	51.5
Total operating expenses	551.2	750.2	1,301.4	1.1	1,302.5
Operating income (loss)	$ 197.1	$ 213.1	$ 410.2	$ (13.1)	$ 397.1
Interest expense, net					(153.7)
Other income, net					2.2
Income tax (expense)					(28.5)
Net income					217.1
Net income attributable to non-controlling interest					(6.9)
Net income available for common stock					$ 210.2

Nine Months Ended September 30, 2025	Consolidating Income Statement				
	Electric Utilities	Gas Utilities	Total Reportable Segments	Corporate and Other	Total
			(in millions)		
Revenue -					
External Customers	$ 699.1	$ 975.4	$ 1,674.5	$ —	$ 1,674.5
Inter-segment	7.2	4.5	11.7	(11.7)	—
Total revenue	706.3	979.9	1,686.2	(11.7)	1,674.5
Fuel, purchased power and cost of natural gas sold	192.2	403.7	595.9	(0.2)	595.7
Operations and maintenance [(a)] -					
Direct	107.9	121.9	229.8	(4.1)	225.7
Allocated	99.9	126.6	226.5	—	226.5
Depreciation and amortization	113.0	97.6	210.6	(0.1)	210.5
Taxes other than income taxes	27.6	22.4	50.0	—	50.0
Total operating expenses	540.6	772.2	1,312.8	(4.4)	1,308.4
Operating income (loss)	$ 165.7	$ 207.7	$ 373.4	$ (7.3)	$ 366.1
Interest expense, net					(149.6)
Other income, net					1.1
Income tax (expense)					(26.5)
Net income					191.1
Net income attributable to non-controlling interest					(4.5)
Net income available for common stock					$ 186.6

(a) Direct and Allocated Operations and maintenance expenses for our operating segments are regularly provided to the CODM. Direct Operations and maintenance expense represents the costs incurred directly by our operating segments. Allocated Operations and maintenance expense represent costs incurred by BHSC for various direct and indirect support services provided to our operating segments. Pursuant to the BHSC Cost Allocation Manual, indirect cost allocations are determined in accordance with the Public Utility Holding Company Act of 2005.

Capital Expenditures [a] for the nine months ended September 30,	2026	2025
	(in millions)	
Electric Utilities	$ 511.0	$ 334.0
Gas Utilities	287.1	267.6
Corporate and Other	6.9	6.9
Total capital expenditures	$ 805.0	$ 608.5

(a) Includes accruals for property, plant, and equipment as disclosed in supplemental cash flow information in the Consolidated Statements of Cash Flows in the Consolidated Financial Statements. Capital expenditures are presented net of CIACs in the Consolidated Statements of Cash Flows.

(13) Selected Balance Sheet Information

Accounts Receivable and Allowance for Credit Losses

Following is a summary of Accounts receivable, net included in the accompanying Consolidated Balance Sheets as of:

	September 30, 2026	December 31, 2025
	(in millions)	
Billed Accounts Receivable	$ 168.8	$ 223.3
Unbilled Revenue	89.9	168.1
Less: Allowance for Credit Losses	(1.9)	(2.4)
Account Receivable, net	$ 256.8	$ 389.0

Changes to allowance for credit losses for the nine months ended September 30, 2026, and 2025, respectively, were as follows:

	Balance at Beginning of Year	Additions Charged to Costs and Expenses	Recoveries and Other Additions	Write-offs and Other Deductions	Balance at September 30,
			(in millions)		
2026	$ 2.4	$ 6.2	$ 2.9	$ (9.6)	$ 1.9
2025	$ 2.1	$ 5.8	$ 2.4	$ (8.2)	$ 2.1

Materials, Supplies and Fuel

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

	September 30, 2026	December 31, 2025
	(in millions)	
Materials and supplies	$ 126.0	$ 117.3
Fuel - Electric Utilities	5.8	6.4
Natural gas in storage	54.5	48.7
Total materials, supplies, and fuel	$ 186.3	$ 172.4

Accrued Liabilities

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

	September 30, 2026	December 31, 2025
	(in millions)	
Accrued employee compensation, benefits, and withholdings	$ 85.8	$ 92.8
Accrued property taxes	50.7	54.8
Customer deposits and prepayments	68.1	59.0
Accrued interest	57.4	57.2
Other (none of which is individually significant)	43.3	58.8
Total accrued liabilities	$ 305.3	$ 322.6

(14) Strategic Transactions

Pending Merger with NorthWestern

On August 18, 2025, we entered into an Agreement and Plan of Merger (the "Merger Agreement"), with NorthWestern and Merger Sub. The Merger Agreement provides for Merger Sub to merge with and into NorthWestern (the "Merger"), with NorthWestern continuing as the surviving entity and a direct wholly owned subsidiary of Black Hills Corporation, which will assume a new corporate name, Bright Horizon Energy Corporation, as the resulting parent company of the combined corporate group. At the effective time of the Merger (the "Effective Time"), each share of common stock of NorthWestern, par value $0.01 per share, issued and outstanding as of immediately prior to the Effective Time will be converted into the right to receive 0.98 validly issued, fully paid and non-assessable shares of our common stock, par value $1.00 per share (or cash-in-lieu of fractional shares thereof), in each case upon and subject to the terms and conditions of the Merger Agreement.

In connection with this pending merger, we have incurred merger-related costs. During the three and nine months ended September 30, 2026, we incurred merger-related costs of $3.1 million and $11.7 million, respectively. During the three and nine months ended September 30, 2025, we incurred merger-related costs of $8.4 million and $8.4 million, respectively. These merger-related costs are included in Operations and maintenance in our Consolidated Statements of Income.

The Merger Agreement, which was unanimously approved on August 18, 2025, by both the board of directors of Black Hills Corporation and the board of directors of NorthWestern, provides for a tax-free, all-stock business combination of Black Hills Corporation and NorthWestern upon the terms and subject to the conditions set forth therein. Such conditions include, among other things, clearance under the HSR Act, approval from each company's shareholders, and regulatory approvals, including approval from the SDPUC, NPSC and MPSC, as well as the FERC. To date, the status of these matters is as follows:

- In October 2025, we filed joint applications for approval with the MPSC, NPSC, and SDPUC.
  - In March 2026, we reached a settlement agreement with all intervening parties in Nebraska. On May 19, 2026, the NPSC approved the Merger.
  - In April 2026, we reached a settlement with the SDPUC Staff, which was filed with the SDPUC. On June 24, 2026, the SDPUC approved the Merger.
  - In April 2026, we reached settlements agreements with several parties in Montana, which were filed with the MPSC. Hearings before the MPSC occurred during the second quarter of 2026. The settlement agreements are subject to approval by the MPSC. The statutory deadline for the MPSC decision is November 12, 2026.
- On December 22, 2025, we filed a joint application with the FERC. The initial public comment period closed on January 20, 2026. On May 29, 2026, we received approval for the Merger from the FERC.
- On January 30, 2026, the Form S-4, which contains a joint proxy statement/prospectus for the Black Hills Corporation and NorthWestern, was publicly filed with the SEC. On February 6, 2026, the Form S-4 was declared effective by the SEC. On April 2, 2026, shareholders from both Black Hills Corporation and NorthWestern voted to approve the proposed all-stock merger.
- In March 2026, we filed an application for clearance under the HSR Act. The waiting period under the HSR Act was completed on April 20, 2026, satisfying a U.S. antitrust condition to closing.

We anticipate the transaction closing by year-end 2026, subject to receipt of a satisfactory approval from the MPSC as mentioned above.

Pending Sale of Investment

In August 2026, we entered into an agreement to sell our minority stake in an investment in equity securities of a privately held oil and gas company. The transaction remains subject to regulatory approvals and other customary closing conditions and is currently expected to close during the fourth quarter of 2026. No gain or loss was recognized during the three and nine months ended September 30, 2026.

(15) Subsequent Events

Except as described below, there have been no events subsequent to September 30, 2026, which would require recognition in the Consolidated Financial Statements or disclosures.

See Note 2 for updates related to the Arkansas Gas and South Dakota Electric rate reviews.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussions should be read in conjunction with the Notes contained herein and Management's Discussion and Analysis of Financial Condition and Results of Operations appearing in our 2025 Annual Report on Form 10-K.

Executive Summary

We are a customer-focused energy solutions provider with a mission of *Improving Life with Energy* for more than 1.37 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 priorities: *People & Culture*—build a team that wins together, *Operational Excellence*—relentlessly deliver on our commitment to serve our customers, *Transformation*—be a simple and connected company and *Growth*—grow to be a dominant long-term energy provider.

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 ourselves a domestic electric and natural gas utility company.

We have provided energy and served customers for 143 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.

Recent Developments

Pending Merger with NorthWestern

On August 18, 2025, we entered into the Merger Agreement with NorthWestern and Merger Sub. We anticipate the transaction closing by year-end 2026, subject to receipt of a satisfactory approval from the MPSC. See Note 14 of the Condensed Notes to Consolidated Financial Statements for further information regarding the pending Merger.

Google Data Center Project

In September 2026, the Company entered into long-term agreements with Google and other third-party partners to serve a planned data center project to be constructed in Cheyenne, Wyoming. The project is contracted to be served through a total resource mix of 2.7 GW, including reserve margins, and is expected to begin taking energy service in late 2027 and ramp to the data center's projected peak load by the end of 2030. We expect to provide up to 590 MW of grid-connected energy service through company-owned generation and market energy. In addition, we expect to manage the output of approximately 2.1 GW of third-party contracted resources through a privately managed microgrid under the Company's LPCS tariff.

To provide 590 MW of grid-connected service, the Company expects to invest approximately $1.8 billion to construct 564 MW (nameplate capacity) of new company-owned natural gas generation between 2027 and 2029 through a non-regulated affiliate, which will be located at the Company's existing CPGS facility. The remaining 26 MW is expected to be supplied through a combination of market energy purchases and retail utility service provided under the Company's applicable industrial tariff.

The Company expects to finance the approximately $1.8 billion of generation investment through a combination of project-generated cash flow and debt and equity instruments with a focus on earnings accretion while maintaining solid investment-grade credit ratings. In connection with the development of the project, the Company previously disclosed customer-funded refundable advances received pursuant to the parties' generation reservation agreement to support procurement of long-lead generation equipment. During the third quarter of 2026, the parties amended the generation reservation agreement to increase the permitted advances to $398.8 million and extend the repayment date to June 30, 2027. The Company expects to reimburse those advances by their June 30, 2027 maturity date.

The agreements include contractual protections throughout the 2048 contract term intended to prevent cost shifting to existing retail customers, including:

- Cost pass-through mechanisms – protect customers from costs associated with the planned data center while protecting returns from inflation, interest rate volatility, and other cost pressures;
- Stranded asset risk protection – provides for full recovery of all generation capital investment over the contract term, protecting customers against risk of stranded assets;
- Early termination protection – safeguard customers and shareholders should the project terminate prior to the end of the agreements' term; and

- Credit protections – strong collateral and financial assurance requirements back the data center's long-term commitments.

The Company has obtained or initiated key regulatory approvals for the project during 2026, including a substation CPCN approval, the filing of an industrial siting permit for the CPGS expansion, and approval of an air quality permit and an industrial siting permit for the CPGS expansion. Additionally, the Company is advancing transmission expansion opportunities through regulatory filings to serve this project and other regional large-load opportunities. See Business Segment Recent Developments section below with further details on these transmission expansion filings.

Business Segment Recent Developments

Electric Utilities

- See Note 2 of the Condensed Notes to Consolidated Financial Statements for recent rate review activity for South Dakota Electric and Colorado Electric.

- In 2026 to date, Wyoming Electric requested approval from the WPSC for a new LCTCAM tariff and CPCNs for two transmission expansion projects with total investment of $686 million to serve the growing energy needs of Wyoming Electric's large-load customers.
  - On June 19, 2026, Wyoming Electric filed a request with the WPSC to establish an LCTCAM tariff. The LCTCAM tariff provides a framework to directly recover transmission investment costs from LPCS customers who are served by, and benefit from, the transmission facilities. The proposed mechanism is designed to ensure that customers not directly served by those facilities are protected from bearing those costs. A WPSC decision is expected in the first quarter of 2027.
  - On September 1, 2026, Wyoming Electric filed a CPCN with the WPSC for its South Cheyenne Transmission Project. The $80 million project includes new substations and nearly 15 miles of transmission lines and upgrades to be in-service in multiple phases in late 2027 through 2028. Recovery is expected to be requested under the LCTCAM, which is currently pending with the WPSC. A WPSC decision on the South Cheyenne Transmission Project CPCN request is expected by mid-2027.
  - On November 2, 2026, Wyoming Electric filed a request with the WPSC for a CPCN for its Aeolus Transmission Project to expand transmission capacity across the Cheyenne region and key interconnection points. The $606 million project includes two new 230-kV transmission lines, with upgrade capabilities to 345-kV, spanning approximately 125 miles. Pending approval by the WPSC, completion of the project is expected by mid-2029. Recovery is expected to be requested under the LCTCAM, which is also pending approval from the WPSC. A WPSC decision on the Aeolus Transmission Project CPCN request is expected by mid-2027.
- During the third quarter of 2026, South Dakota Electric continued with construction of its Lange II project which is anticipated to be in service by year-end 2026. The addition of these resources will replace generation facilities planned for retirement and support updated planning reserve margin requirements. On August 4, 2026, South Dakota Electric filed an application with the SDPUC for a PIPR rider which requests recovery of $320 million of Lange II project costs outside of a general rate review. If approved by the SDPUC, the rider is anticipated to be effective on December 1, 2026.
- On September 11, 2026, Colorado Electric filed its 2026 Clean Energy Plan with the CPUC. The updated plan builds on Colorado Electric's 2022 Clean Energy Plan. The plan includes a 25-year planning horizon and reliably achieves Colorado’s statutory requirement to reduce greenhouse gas emissions by 80% by 2030, based on 2005 levels. To meet these objectives, the plan proposes the addition of 100 MW of wind energy, 200 MW of battery energy storage systems and 125 MW of firm, dispatchable natural gas-fired generation.
- On March 12, 2026, the state of South Dakota enacted comprehensive wildfire liability mitigation legislation (Senate Bill 36), effective July 1, 2026. The legislation provides material liability protections for a utility that complies with its published wildfire mitigation plan. On July 2, 2026, South Dakota Electric filed its WMP with the SDPUC. Under Senate Bill 36, a utility's WMP is valid and current if it is on file and all annual reports are timely filed with the SDPUC. In 2025, the state of Wyoming enacted similar legislation. In November 2025, Wyoming Electric filed its WMP with the WPSC, which was approved on July 9, 2026.
- On June 30, 2026, Wyoming Electric submitted an IRP to the WPSC. The IRP, which is based on 20-year planning period including a near-term planning period through 2033, identified a near-term capacity shortfall of 95 MW beginning in 2027. Based on its forecasts and analysis, Wyoming Electric recommends the addition of natural gas-fired generation, battery storage assets and energy market purchases to meet the identified resource need. Wyoming Electric's IRP does not address any LPCS Tariff capacity needs, which are handled separately under customer-specific agreements.
- In 2026, Wyoming Electric has set multiple all-time records for System Peak Demand driven by growth in large-load data center demand. The most recent all-time peak of 439 MW was set on July 20, 2026. Prior to 2026, the previous all-time peak was 379 MW set on June 20, 2025.

- In 2025, Colorado Electric received CPUC approval for the addition of 250 MW of new renewable generation resources in support of its Clean Energy Plan, which included a 50-MW utility-owned battery storage project and a 200-MW solar PPA. During the fourth quarter of 2025, Colorado Electric commenced construction of the 50-MW battery storage project. The project is expected to be completed by year-end 2027. On February 18, 2026, Colorado Electric entered into a 200-MW solar PPA. See Note 3 of the Condensed Notes to Consolidated Financial Statements for additional information regarding the PPA.

Gas Utilities

- See Note 2 of the Condensed Notes to Consolidated Financial Statements for recent rate review activity for Arkansas Gas, Kansas Gas and Nebraska Gas.

Corporate and Other

- See Note 5 of the Condensed Notes to Consolidated Financial Statements for information regarding recent financing activities.
- During the second quarter of 2026, we published our 2025 Corporate Sustainability Report, highlighting our environmental, social and governance impacts and our progress on major projects and climate goals. We reported a 43% reduction in electric utility emissions intensity compared to 2005, driven by the addition of renewable and natural gas resources and the retirement of aging power plants. We also reduced natural gas utility emissions by 25% since 2022, including a 53% reduction from transfer stations, reflecting progress toward our net-zero by 2035 goal through expanded leak detection and repair efforts.

Results of Operations

Certain lines of business in which we operate are highly seasonal, and revenue from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements. In particular, the normal peak usage season for our Electric Utilities is June through August while the normal peak usage season for our Gas Utilities is November through March. Significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and nine months ended September 30, 2026, and 2025, and our financial condition as of September 30, 2026, and December 31, 2025, are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period or for the entire year.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2026	2025	2026 vs 2025 Variance	2026	2025	2026 vs 2025 Variance
	(in millions, except per share amounts)					
Operating income (loss):						
Electric Utilities	$ 76.9	$ 62.4	$ 14.5	$ 197.1	$ 165.7	$ 31.4
Gas Utilities	25.0	20.8	4.2	213.1	207.7	5.4
Corporate and Other [(a)]	(3.8)	(4.5)	0.7	(13.1)	(7.3)	(5.8)
Operating income	98.1	78.7	19.4	397.1	366.1	31.0
Interest expense, net	(50.1)	(49.4)	(0.7)	(153.7)	(149.6)	(4.1)
Other income, net	1.3	0.6	0.7	2.2	1.1	1.1
Income tax (expense)	(5.8)	(4.0)	(1.8)	(28.5)	(26.5)	(2.0)
Net income	43.5	25.9	17.6	217.1	191.1	26.0
Net income attributable to non-controlling interest	(2.5)	(1.0)	(1.5)	(6.9)	(4.5)	(2.4)
Net income available for common stock	$ 41.0	$ 24.9	$ 16.1	$ 210.2	$ 186.6	$ 23.6
Weighted average common shares outstanding, Diluted	76.4	72.9	3.5	76.1	72.4	3.7
Total earnings per share of common stock, Diluted	$ 0.54	$ 0.34	$ 0.20	$ 2.76	$ 2.58	$ 0.18

(a) Includes inter-segment eliminations.

Three Months Ended September 30, 2026, Compared to the Three Months Ended September 30, 2025:

- Electric Utilities' operating income increased $14.5 million primarily due to new rates driven by the South Dakota Electric rate review (interim rates effective August 2026) and rider recovery driven by Wyoming Electric's Ready Wyoming project, favorable weather and increased retail customer usage.
- Gas Utilities' operating income increased $4.2 million primarily due to new rates and rider recovery driven by the Nebraska Gas rate review, increased retail customer usage, increased transportation volumes, and favorable weather partially offset by higher operating expenses.

Nine Months Ended September 30, 2026, Compared to the Nine Months Ended September 30, 2025:

- Electric Utilities' operating income increased $31.4 million primarily due to new rates and rider recovery driven by the Colorado Electric and South Dakota Electric rate reviews and Wyoming Electric's Ready Wyoming project partially offset by higher operating expenses.
- Gas Utilities' operating income increased $5.4 million primarily due to new rates and rider recovery driven by the Nebraska Gas and Kansas Gas rate reviews, increased transportation volumes and customer growth partially offset by unfavorable weather and higher operating expenses.
- Corporate and Other operating loss increased $5.8 million primarily due to higher costs related to the pending Merger and the prior year consolidation of our Captive insurance cell.
- Net interest expense increased $4.1 million primarily due to higher rates on higher debt balances.
- Income tax expense increased $2.0 million due to higher pre-tax income partially offset by a lower effective tax rate primarily driven by increased current year tax benefits from federal PTCs associated with increased wind production.
- Net income attributable to non-controlling interest increased $2.4 million due to higher net income from Black Hills Colorado IPP primarily driven by prior year unplanned generation outages.

Segment Operating Results

A discussion of operating results from our business segments follows. Unless otherwise indicated, segment information does not include inter-segment eliminations.

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with GAAP and a “non-GAAP financial measure", Electric and Gas Utility margin. 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. We define Electric and Gas Utility margin as operating revenue less cost of fuel, purchased power and cost of natural gas sold. Electric and Gas Utility margin is a non-GAAP financial measure due to the exclusion of operation and maintenance expenses determined to be directly attributable to revenue-producing activities, depreciation and amortization expenses, and taxes other than income taxes from the measure.

We believe that Gas and Electric Utility margin provides a useful basis for evaluating our segment operating results since our Utilities have regulatory mechanisms that allow them to pass prudently incurred costs of energy through to the customer in current rates. As a result, management uses Gas and Electric Utility margin internally when assessing the financial performance of our operating segments as this measure excludes the majority of revenue fluctuations caused by changes in these costs of energy. Similarly, the presentation of Gas and Electric Utility margin is intended to supplement investors’ understanding of operating performance.

Our Electric and Gas Utility margin measure may not be comparable to other companies' Electric and Gas Utility margin measures. The following table includes a reconciliation of Electric and Gas Utility margin to Gross margin, the most directly comparable GAAP measure:

	Electric Utilities				Gas Utilities			
	Three Months Ended September 30,		Nine Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025	2026	2025	2026	2025
	(in millions)							
Revenue	$ 280.4	$ 249.7	$ 748.3	$ 706.3	$ 189.7	$ 184.4	$ 963.3	$ 979.9
Fuel, purchased power and cost of natural gas sold	(81.8)	(69.8)	(198.3)	(192.2)	(39.7)	(42.3)	(374.8)	(403.7)
Operations and maintenance [(a)]	(44.5)	(44.4)	(125.3)	(130.1)	(42.3)	(42.0)	(126.3)	(129.0)
Depreciation and amortization	(41.9)	(38.3)	(123.3)	(113.0)	(34.3)	(33.2)	(103.0)	(97.6)
Taxes other than income taxes	(9.1)	(9.4)	(27.5)	(27.6)	(7.9)	(7.8)	(24.0)	(22.4)
Gross margin (GAAP)	$ 103.1	$ 87.8	$ 273.9	$ 243.4	$ 65.5	$ 59.1	$ 335.2	$ 327.2
Operations and maintenance [(a)]	44.5	44.4	125.3	130.1	42.3	42.0	126.3	129.0
Depreciation and amortization	41.9	38.3	123.3	113.0	34.3	33.2	103.0	97.6
Taxes other than income taxes	9.1	9.4	27.5	27.6	7.9	7.8	24.0	22.4
Electric and Gas Utility margin (non-GAAP)	$ 198.6	$ 179.9	$ 550.0	$ 514.1	$ 150.0	$ 142.1	$ 588.5	$ 576.2

(a) Operations and maintenance expenses which are deemed to be directly attributable to revenue-producing activities include plant operations and maintenance expenses at our electric generation facilities, operations and maintenance expenses at our WRDC coal mine, and electric and gas transmission and distribution expenses. These amounts are included in the table above to calculate gross margin in accordance with GAAP. These amounts excluded operations and maintenance expenses not directly attributable to revenue-producing activities of $26.2 million, $25.4 million, $76.8 million, and $77.7 million for the three and nine months ended September 30, 2026, and 2025, respectively, for the Electric Utilities and $40.5 million, $38.3 million, $122.1 million, and $119.5 million for the three and nine months ended September 30, 2026, and 2025, respectively, for the Gas Utilities.

Electric Utilities

Operating results for the Electric Utilities were as follows:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2026	2025	2026 vs 2025 Variance	2026	2025	2026 vs 2025 Variance
			(in millions)			
Revenue	$ 280.4	$ 249.7	$ 30.7	$ 748.3	$ 706.3	$ 42.0
Fuel and purchased power	81.8	69.8	12.0	198.3	192.2	6.1
Electric Utility margin (non-GAAP) [(a)]	198.6	179.9	18.7	550.0	514.1	35.9
Operations and maintenance	70.7	69.8	0.9	202.1	207.8	(5.7)
Depreciation and amortization	41.9	38.3	3.6	123.3	113.0	10.3
Taxes other than income taxes	9.1	9.4	(0.3)	27.5	27.6	(0.1)
Total operating expenses (excluding Fuel and purchased power)	121.7	117.5	4.2	352.9	348.4	4.5
Operating income	$ 76.9	$ 62.4	$ 14.5	$ 197.1	$ 165.7	$ 31.4

(a) See Non-GAAP Financial Measures section above for reconciliation to Gross margin, the most directly comparable GAAP measure.

Three Months Ended September 30, 2026, Compared to the Three Months Ended September 30, 2025:

- Electric Utility margin increased as a result of the following:

	(in millions)
New rates and rider recovery	$ 11.4
Weather	4.5
Residential and commercial customer usage	2.9
Other	(0.1)
	$ 18.7

- Operations and maintenance expense was comparable primarily due to increased employee-related costs and outside services expenses mostly offset by lower expenses related to prior year unplanned generation outages.
- Depreciation and amortization increased primarily due to higher asset base driven by capital expenditures.
- Taxes other than income taxes were comparable to the same period in the prior year.

Nine Months Ended September 30, 2026, Compared to the Nine Months Ended September 30, 2025:

- Electric Utility margin increased as a result of the following:

	(in millions)
New rates and rider recovery	$ 32.9
Weather	1.7
Other	1.3
	$ 35.9

- Operations and maintenance expense decreased primarily due to $4.8 million of lower expenses related to prior year unplanned generation outages and $2.7 million of lower outside services expenses partially offset by higher employee costs.
- Depreciation and amortization increased primarily due to higher asset base driven by capital expenditures.
- Taxes other than income taxes were comparable to the same period in the prior year.

Operating Statistics

	Revenue				Quantities Sold			
	Three Months Ended September 30,		Nine Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
By Customer Class	**2026**	**2025**	**2026**	**2025**	**2026**	**2025**	**2026**	**2025**
	(in millions)				(in GWh)			
Retail Revenue -								
Residential	$ 78.8	$ 68.8	$ 197.9	$ 189.3	448.2	393.5	1,134.1	1,120.9
Commercial	76.5	74.6	213.9	210.3	573.7	561.6	1,565.5	1,578.5
Industrial [(a)]	64.2	49.8	178.7	147.3	770.1	639.1	2,261.5	1,912.8
Municipal	5.3	4.6	13.9	13.4	43.0	41.4	109.9	110.1
Other Retail	3.0	3.5	4.8	10.3	—	—	—	—
Subtotal Retail Revenue - Electric	227.8	201.3	609.2	570.6	1,835.0	1,635.6	5,071.0	4,722.3
Wholesale	6.4	5.5	17.7	16.9	128.0	110.5	391.6	366.7
Market - off-system sales	9.7	16.3	23.0	38.3	256.9	267.0	545.5	660.6
Transmission	20.8	11.1	50.3	33.3	—	—	—	—
Other [(b)]	15.7	15.5	48.1	47.2	—	—	—	—
Total Revenue and Quantities Sold	$ 280.4	$ 249.7	$ 748.3	$ 706.3	2,219.9	2,013.1	6,008.1	5,749.6
Other Uses, Losses, or Generation, net [(c)]					148.6	112.9	394.2	332.4
Total Energy					2,368.5	2,126.0	6,402.3	6,082.0

(a) The increase in industrial quantities sold for the three and nine months ended September 30, 2026, compared to the same periods in 2025, was primarily driven by Wyoming Electric's large-load customers under the LPCS and BCIS Tariffs.
(b) Includes Integrated Generation, inter-segment rent, and non-regulated services to our retail customers under the Service Guard Comfort Plan and Tech Services.
(c) Includes company uses and line losses.

By Business Unit	Revenue				Quantities Sold			
	Three Months Ended September 30,		Nine Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025	2026	2025	2026	2025
	(in millions)				(in GWh)			
Colorado Electric	$ 86.8	$ 79.6	$ 220.7	$ 218.3	568.6	621.3	1,599.4	1,677.7
South Dakota Electric	95.1	90.6	257.7	255.5	769.5	711.8	1,976.2	2,032.7
Wyoming Electric	87.1	68.6	237.6	200.0	856.9	659.9	2,360.5	1,970.9
Integrated Generation	11.4	10.9	32.3	32.5	24.9	20.1	72.0	68.3
Total Revenue and Quantities Sold	$ 280.4	$ 249.7	$ 748.3	$ 706.3	2,219.9	2,013.1	6,008.1	5,749.6

Quantities Generated and Purchased by Fuel Type	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
	(in GWh)			
Generated:				
Coal	628.3	556.8	1,702.4	1,614.1
Natural Gas and Oil	640.9	718.7	1,584.3	1,816.1
Wind	128.1	115.7	477.5	426.5
Total Generated	1,397.3	1,391.2	3,764.2	3,856.7
Purchased:				
Coal, Natural Gas, Oil, and Other Market Purchases	696.8	458.9	1,667.7	1,305.4
Wind and Solar	274.4	275.9	970.4	919.9
Total Purchased [(a)]	971.2	734.8	2,638.1	2,225.3
Total Generated and Purchased	2,368.5	2,126.0	6,402.3	6,082.0

(a) The increase in total purchases for the three and nine months ended September 30, 2026, compared to the same period in 2025, was primarily driven by increased demand from Wyoming Electric's large-load customers under the LPCS and BCIS Tariffs.

Quantities Generated and Purchased by Business Unit	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
	(in GWh)			
Generated:				
Colorado Electric	134.9	228.1	459.2	595.5
South Dakota Electric	526.4	453.8	1,373.6	1,377.6
Wyoming Electric	248.2	236.9	645.5	676.3
Integrated Generation	487.8	472.4	1,285.9	1,207.3
Total Generated	1,397.3	1,391.2	3,764.2	3,856.7
Purchased:				
Colorado Electric	127.7	72.8	315.1	269.5
South Dakota Electric	267.5	294.7	691.7	738.6
Wyoming Electric [(a)]	520.2	357.7	1,534.3	1,173.5
Integrated Generation	55.8	9.6	97.0	43.7
Total Purchased	971.2	734.8	2,638.1	2,225.3
Total Generated and Purchased	2,368.5	2,126.0	6,402.3	6,082.0

(a) As discussed in footnote (a) in the Quantities Generated and Purchased by Fuel Type table above, the increase in Wyoming Electric's purchases for the three and nine months ended September 30, 2026, compared to the same periods in 2025, is primarily driven by increased demand from large-load customers under the LPCS and BCIS Tariffs.

Degree Days	Three Months Ended September 30, 2026 Actual	2026 Variance from Normal	2025 Actual	2025 Variance from Normal	Nine Months Ended September 30, 2026 Actual	2026 Variance from Normal	2025 Actual	2025 Variance from Normal
Heating Degree Days:								
Colorado Electric	17	(61)%	34	(15)%	2,557	(19)%	3,390	8%
South Dakota Electric	71	(50)%	86	(41)%	3,618	(19)%	4,432	---
Wyoming Electric	85	(47)%	157	---	3,384	(22)%	4,382	2%
Combined [(a)]	50	(51)%	77	(24)%	3,094	(20)%	3,952	3%
Cooling Degree Days:								
Colorado Electric	1,056	22%	770	(13)%	1,414	23%	1,005	(14)%
South Dakota Electric	767	37%	598	10%	869	27%	760	15%
Wyoming Electric	522	32%	277	(31)%	569	19%	337	(30)%
Combined [(a)]	847	28%	610	(8)%	1,053	24%	785	(8)%

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

Gas Utilities

Operating results for the Gas Utilities were as follows:

	Three Months Ended September 30, 2026	2025	2026 vs 2025 Variance	Nine Months Ended September 30, 2026	2025	2026 vs 2025 Variance
			(in millions)			
Revenue	$ 189.7	$ 184.4	$ 5.3	$ 963.3	$ 979.9	$ (16.6)
Cost of natural gas sold	39.7	42.3	(2.6)	374.8	403.7	(28.9)
Gas Utility margin (non-GAAP) [(a)]	150.0	142.1	7.9	588.5	576.2	12.3
Operations and maintenance	82.8	80.3	2.5	248.4	248.5	(0.1)
Depreciation and amortization	34.3	33.2	1.1	103.0	97.6	5.4
Taxes other than income taxes	7.9	7.8	0.1	24.0	22.4	1.6
Total operating expenses (excluding Cost of natural gas sold)	125.0	121.3	3.7	375.4	368.5	6.9
Operating income	$ 25.0	$ 20.8	$ 4.2	$ 213.1	$ 207.7	$ 5.4

(a) See Non-GAAP Financial Measures section above for reconciliation to Gross margin, the most directly comparable GAAP measure.

Three Months Ended September 30, 2026, Compared to the Three Months Ended September 30, 2025:

- Gas Utility margin increased as a result of the following:

	(in millions)
New rates and rider recovery	$ 2.9
Transportation volumes	1.5
Retail customer usage	1.1
Weather	1.0
Other	1.4
	$ 7.9

- Operations and maintenance expense increased primarily due to higher employee-related costs partially offset by lower outside services expenses.
- Depreciation and amortization were comparable to the same period in the prior year.
- Taxes other than income taxes were comparable to the same period in the prior year.

Nine Months Ended September 30, 2026, Compared to the Nine Months Ended September 30, 2025:

- Gas Utility margin increased as a result of the following:

	(in millions)
New rates and rider recovery	$ 22.8
Transportation volumes	2.8
Customer growth	2.7
Weather	(12.6)
Retail customer usage	(1.7)
Other	(1.7)
	$ 12.3

- Operations and maintenance expense was comparable to the same period in the prior year.
- Depreciation and amortization increased primarily due to higher asset base driven by capital expenditures.
- Taxes other than income taxes were comparable to the same period in the prior year.

Operating Statistics

	Revenue				Quantities Sold and Transported			
	Three Months Ended September 30,		Nine Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
By Customer Class	**2026**	**2025**	**2026**	**2025**	**2026**	**2025**	**2026**	**2025**
	(in millions)				(Dth in millions)			
Retail Revenue -								
Residential	$ 83.6	$ 86.0	$ 506.9	$ 543.4	3.4	3.6	35.3	41.5
Commercial	28.2	30.0	193.4	206.3	2.4	2.5	18.3	20.5
Industrial	9.9	8.2	23.7	21.3	2.6	2.0	5.2	4.4
Other Retail [(a)]	6.2	4.4	27.7	26.0	—	—	—	—
Subtotal Retail Revenue - Gas	127.9	128.6	751.7	797.0	8.4	8.1	58.8	66.4
Transportation	47.2	43.6	146.5	143.4	37.4	36.2	121.6	122.8
Other [(b) (c)]	14.6	12.2	65.1	39.5	—	—	—	—
Total Revenue and Quantities Sold	$ 189.7	$ 184.4	$ 963.3	$ 979.9	45.8	44.3	180.4	189.2

(a) Includes Black Hills Energy Services revenue under the Choice Gas Program.
(b) Includes inter-segment rent and non-regulated services under the Service Guard Comfort Plan, Tech Services, and HomeServe.
(c) The increase in Other Revenue for the nine months ended September 30, 2026 was primarily driven by an increase in weather normalization mechanism revenue, including the implementation of the Nebraska Gas's pilot program effective August 2025.

	Revenue				Quantities Sold and Transported			
	Three Months Ended September 30,		Nine Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
By Business Unit	**2026**	**2025**	**2026**	**2025**	**2026**	**2025**	**2026**	**2025**
	(in millions)				(Dth in millions)			
Arkansas Gas	$ 28.5	$ 31.0	$ 192.1	$ 196.5	4.9	4.9	22.0	23.4
Colorado Gas	26.8	27.9	153.8	182.7	3.3	3.5	19.0	21.9
Iowa Gas	23.0	21.7	149.9	138.6	6.0	6.1	27.2	28.1
Kansas Gas	26.8	23.7	113.2	114.9	10.1	8.6	29.1	27.9
Nebraska Gas	61.7	57.2	256.1	245.4	15.8	15.6	58.2	61.7
Wyoming Gas	22.9	22.9	98.2	101.8	5.7	5.6	24.9	26.2
Total Revenue and Quantities Sold	$ 189.7	$ 184.4	$ 963.3	$ 979.9	45.8	44.3	180.4	189.2

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2026		2025		2026		2025	
Heating Degree Days	Actual	Variance from Normal	Actual	Variance from Normal	Actual	Variance from Normal	Actual	Variance from Normal
Arkansas Gas [(a)]	---	(100)%	1	(92)%	1,727	(20)%	2,151	(3)%
Colorado Gas	59	(46)%	99	(7)%	2,834	(25)%	3,758	---
Iowa Gas	54	(26)%	75	2%	3,645	(10)%	4,003	(1)%
Kansas Gas [(a)]	1	(96)%	18	(20)%	2,309	(18)%	3,001	7%
Nebraska Gas [(a)]	20	(62)%	41	(23)%	3,097	(15)%	3,633	---
Wyoming Gas	109	(45)%	153	(22)%	3,634	(22)%	4,586	---
Combined [(b)]	53	(57)%	71	(11)%	3,223	(22)%	3,811	(1)%

(a) Arkansas Gas and Kansas Gas have weather normalization mechanisms that mitigate the weather impact on Gas Utility margins. Nebraska Gas received NPSC approval to implement a two-year pilot program for a weather normalization mechanism which was effective August 1, 2025.

(b) The combined heating degree days are calculated based on a weighted average of total customers by state excluding Kansas Gas and Nebraska Gas (effective in August 2025) 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 consists of certain unallocated expenses for administrative activities that support our operating segments. Corporate and Other also includes our Captive, business development activities that are not part of our operating segments, and inter-segment eliminations.

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2026	2025	2026 vs 2025 Variance	2026	2025	2026 vs 2025 Variance
	(in millions)					
Operating income (loss)	$ (3.8)	$ (4.5)	$ 0.7	$ (13.1)	$ (7.3)	$ (5.8)

Three Months Ended September 30, 2026, Compared to the Three Months Ended September 30, 2025:

- Operating loss was comparable primarily due to lower costs related to the pending Merger mostly offset by higher unallocated employee costs and the prior year consolidation of our Captive insurance cell.

Nine Months Ended September 30, 2026, Compared to the Nine Months Ended September 30, 2025:

- Operating loss increased due to $11.7 million of current year costs related to the pending Merger compared to $8.4 million for the same period in 2025. The remaining variance is primarily driven by the prior year consolidation of our Captive insurance cell.

Consolidated Interest Expense, Other Income and Income Tax Expense

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2026	2025	2026 vs 2025 Variance	2026	2025	2026 vs 2025 Variance
	(in millions)					
Interest expense, net	$ (50.1)	$ (49.4)	$ (0.7)	$ (153.7)	$ (149.6)	$ (4.1)
Other income, net	1.3	0.6	0.7	2.2	1.1	1.1
Income tax (expense)	(5.8)	(4.0)	(1.8)	(28.5)	(26.5)	(2.0)

Three Months Ended September 30, 2026, Compared to the Three Months Ended September 30, 2025:

- Interest expense, net, was comparable to the same period in the prior year.
- Other income, net, was comparable to the same period in the prior year.
- Income tax (expense) increased compared to the same period in the prior year primarily due to higher pre-tax income. For the three months ended September 30, 2026, the effective tax rate was 11.8%, which was lower compared to 13.4% for the same period in 2025. The lower effective tax rate was primarily driven by increased current year tax benefits from federal PTCs associated with increased wind production and the non-deductibility of certain prior year costs related to the pending Merger.

Nine Months Ended September 30, 2026, Compared to the Nine Months Ended September 30, 2025:

- Interest expense, net, increased compared to the same period in the prior year primarily driven by higher debt balances partially offset by higher AFUDC debt driven by construction work-in-progress balances.
- Other income, net, was comparable to the same period in the prior year.
- Income tax (expense) increased compared to the same period in the prior year primarily due to higher pre-tax income. For the nine months ended September 30, 2026, the effective tax rate was 11.6%, which was lower compared to 12.2% for the same period in 2025. The lower effective tax rate was primarily driven by increased current year tax benefits from federal PTCs associated with increased wind production.

Liquidity and Capital Resources

The following table provides an informational summary of our liquidity and capital structure as of:

	September 30, 2026	December 31, 2025
	(dollars in millions)	
Cash and cash equivalents	$ 18.2	$ 182.8
Available capacity under Revolving Credit Facility and CP Program [(a)]	684.8	746.8
Available liquidity	$ 703.0	$ 929.6
Capital structure		
Short-term debt		
Notes Payable	$ 61.5	$ —
Current maturities of long-term debt	410.0	—
Refundable advances for construction	398.8	—
Long-term debt	3,995.3	4,701.1
Total debt [(b)]	4,865.6	4,701.1
Total stockholders' equity (excludes non-controlling interest)	3,952.8	3,823.6
Total capitalization	$ 8,818.4	$ 8,524.7
Debt to capitalization	55.2%	55.1%
Long-term debt to total debt	82.1%	100.0%

(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 5 of the Notes to Consolidated Financial Statements for more information.

(b) Total debt includes $398.8 million of Refundable advances for construction, which are excluded from Consolidated Indebtedness as defined under our Revolving Credit Facility and from debt under Wyoming Electric's financing agreements (see Note 5 of the Notes to Consolidated Financial Statements for more information).

Future Financing Plans

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, the issuance of common stock under our ATM or in a secondary offering, a term loan and refundable advances from customers. We plan to re-finance our $400 million, 3.15%, senior unsecured notes due January 15, 2027, at or before the maturity date.

As discussed in the Recent Developments section above, the Company expects to finance the approximately $1.8 billion of generation investment through a combination of project-generated cash flow and debt and equity instruments with a focus on earnings accretion while maintaining solid investment-grade credit ratings. Google has provided us with $398.8 million of refundable advances for the procurement of long lead-time equipment under the parties' generation reservation agreement. We expect to reimburse those advances by their June 30, 2027 maturity date.

CASH FLOW ACTIVITIES

The following tables summarize our cash flows for the nine months ended September 30, 2026:

Operating Activities:

	Nine Months Ended September 30,		2026 vs 2025 Variance
	2026	2025	
	(in millions)		
Net income	$ 217.1	$ 191.1	$ 26.0
Non-cash adjustments to Net income	300.6	278.0	22.6
Total earnings	$ 517.7	$ 469.1	$ 48.6
Changes in certain operating assets and liabilities:			
Materials, supplies and fuel, Accounts receivable and other current assets	127.0	71.8	55.2
Accounts payable and other current liabilities	(80.5)	(70.4)	(10.1)
Regulatory assets	1.7	47.1	(45.4)
Net inflow (outflow) from changes in certain operating assets and liabilities	$ 48.2	$ 48.5	$ (0.3)
Other operating activities	(23.3)	(12.3)	(11.0)
Net cash provided by operating activities	$ 542.6	$ 505.3	$ 37.3

Nine Months Ended September 30, 2026, Compared to the Nine Months Ended September 30, 2025

- Total earnings (net income plus non-cash adjustments) were $48.6 million higher than the same period in the prior year primarily as a result of increased Electric and Gas Utility margins due to new rates and rider recovery partially offset by higher financing costs.
- Net inflows from changes in certain operating assets and liabilities were $0.3 million lower, primarily attributable to:
  - Cash inflows increased by $55.2 million as a result of changes in accounts receivable and other current assets primarily driven by fluctuations in commodity prices and weather, and receipt of an insurance loss recovery receivable related to a legal settlement in Colorado;
  - Cash outflows increased by $10.1 million as a result of changes in accounts payable and other current liabilities primarily driven by fluctuations in commodity prices, payment of a legal liability from settlement in Colorado and changes in other working capital requirements; and
  - Cash inflows decreased by $45.4 million as a result of changes in our regulatory assets and liabilities primarily due to lower recoveries of gas and fuel cost adjustments driven by fluctuations in commodity prices, and lower recoveries of our Winter Storm Uri regulatory asset as recovery is now complete in nearly all jurisdictions.
- Cash outflows from other operating activities increased by $11.0 million primarily driven by settlement of contractor retainage balances from Wyoming Electric's completed Ready Wyoming project and higher costs from cloud computing arrangements.

Investing Activities:

	Nine Months Ended September 30,		2026 vs 2025 Variance
	2026	2025	
	(in millions)		
Capital expenditures	$ (756.0)	$ (550.2)	$ (205.8)
Other investing activities	(7.7)	(6.2)	(1.5)
Net cash (used in) investing activities	$ (763.7)	$ (556.4)	$ (207.3)

Nine Months Ended September 30, 2026, Compared to the Nine Months Ended September 30, 2025

- Cash outflows from capital expenditures increased $205.8 million primarily driven by the Lange II project and milestone payments for long lead-time generation equipment for the Google data center project.
- Cash outflows from other investing activities were comparable to the same period in the prior year.

Financing Activities:

	Nine Months Ended September 30,		
	2026	2025	2026 vs 2025 Variance
	(in millions)		
Dividends paid on common stock	$ (160.2)	$ (146.8)	$ (13.4)
Common stock issued	68.9	219.2	(150.3)
Short-term and long-term debt borrowings (repayments), net	(238.5)	(7.8)	(230.7)
Distributions to non-controlling interests	(9.3)	(5.2)	(4.1)
Proceeds from refundable advances for construction	398.8	—	398.8
Other financing activities	(2.5)	(2.6)	0.1
Net cash provided by financing activities	$ 57.2	$ 56.8	$ 0.4

Nine Months Ended September 30, 2026, Compared to the Nine Months Ended September 30, 2025

- Dividends paid on common stock increased $13.4 million due to the increased dividend rate per share and increased number of common shares outstanding.
- Cash inflows decreased $150.3 million due to decreased issuances of common stock under our ATM.
- Net cash outflows increased $230.7 million primarily as a result of the repayment of $300 million, 3.95% senior unsecured notes on their January 15, 2026 maturity date partially offset by net borrowing activity under our CP Program.
- Distributions to non-controlling interests increased due to higher net income from Black Hills Colorado IPP primarily driven by prior year unplanned generation outages.
- Cash inflows increased due to $398.8 million of refundable advances from Google for long lead-time generation equipment.
- Cash outflows from other financing activities were comparable to the same period in the prior year.

CAPITAL RESOURCES

See Note 5 of the Condensed Notes to Consolidated Financial Statements for recent financing updates and financial covenants information.

CREDIT RATINGS

The following table represents the credit ratings and outlook and risk profile of BHC as of the date of this report:

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

(a) On October 7, 2026, S&P affirmed our BBB+ rating and maintained a Stable outlook.
(b) On October 19, 2026, Moody's affirmed our Baa2 rating and maintained a Stable outlook.

The following table represents the credit rating of South Dakota Electric as of the date of this report:

Rating Agency	Senior Secured Rating
S&P	A

CAPITAL REQUIREMENTS

Common Stock Dividends

Dividends paid on our common stock totaled $160.2 million for the nine months ended September 30, 2026. The quarterly cash dividend was $0.703 per share. On October 28, 2026, our board of directors declared a quarterly dividend of $0.703 per share payable December 1, 2026, equivalent to an annual dividend of $2.812 per share. The amount of any future cash dividends to be declared and paid, if any, will depend upon, among other things, our financial condition, funds from operations, the level of our capital expenditures, restrictions under our Revolving Credit Facility, and our future business prospects.

Critical Accounting Estimates

A summary of our critical accounting estimates is included in our 2025 Annual Report on Form 10-K. There were no material changes made as of September 30, 2026.

New Accounting Pronouncements

See Note 1 of the Condensed Notes to Consolidated Financial Statements for a description of recent accounting pronouncements, if any, and our expectation of their impact on our results of operations and financial condition.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

There have been no material changes to our quantitative and qualitative disclosures about market risk previously disclosed in Item 7A of our 2025 Annual Report on Form 10-K.

ITEM 4. 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, as amended (the "Exchange Act")) as of September 30, 2026. Based on their evaluation, they have concluded that our disclosure controls and procedures were effective at September 30, 2026.

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 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 September 30, 2026, there have been no changes in our internal controls over financial reporting that have materially affected, or are reasonably likely, to materially affect our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see Note 3 of the Condensed Notes to Consolidated Financial Statements and Note 3 in Item 8 of our 2025 Annual Report on Form 10-K.

ITEM 1A. RISK FACTORS

Except as discussed below, there have been no material changes to the risk factors previously disclosed in Item 1A of Part I in our 2025 Annual Report on Form 10-K.

Our anticipated benefits from the Google data center project are dependent on a single customer and long-term demand for data center services and electric power.

Our agreements with Google represent a significant long-term growth opportunity and are expected to contribute meaningfully to future revenues, earnings, cash flows and capital investment. As a result, we will have increased exposure to a single large customer and to trends affecting the data center, cloud computing and artificial intelligence industries. If Google delays, reduces, suspends, relocates or terminates all or a portion of its planned operations, elects to pursue alternative energy solutions, experiences financial difficulties, or otherwise reduces its demand for electric service, our anticipated benefits from the project could be adversely affected.

In addition, forecasts regarding future electricity demand associated with data centers, cloud computing and artificial intelligence applications are subject to significant uncertainty. Technological advancements, increased computing efficiency, changes in customer business strategies, economic conditions, regulatory developments or reduced demand for data center services could reduce projected load growth and adversely affect the utilization and economics of assets constructed to support the project. Although the agreements contain customer credit support, termination payment and other investment recovery provisions, those protections may not fully mitigate the impact of reduced customer demand, contract disputes, non-renewal or customer default.

In addition, the scale of anticipated investments associated with large-load customer growth opportunities, including data center development, may increase our exposure to construction, permitting, regulatory approval and financing risks, which are discussed elsewhere in this Quarterly Report on Form 10-Q and in our 2025 Annual Report on Form 10-K.

The contractual arrangements supporting the Google data center project differ from our traditional utility operations and may not provide the returns or investment recovery we expect.

The Google project is supported by long-term negotiated contractual arrangements that differ from the rate-regulated framework applicable to many of our traditional utility operations. Although the agreements include provisions intended to support recovery of capital investments, operating expenses, fuel costs, financing costs and other project-related expenditures, our ability to achieve expected returns depends on successful project execution, compliance with contractual obligations and the continued performance of the customer and other counterparties.

The project also exposes us to risks associated with contract interpretation, dispute resolution, enforcement of contractual remedies and the collection of amounts owed by counterparties. While the agreements include credit support, termination payments and other mechanisms intended to mitigate stranded asset and investment recovery risks, such provisions may not be sufficient under all circumstances. Because portions of the project's generation assets and related infrastructure are being developed to serve a specific large-load customer, we may not be able to readily redeploy such assets or replace the associated revenue stream if that customer ceases operations, reduces load, defaults under its agreements, or elects not to renew applicable arrangements. If we are unable to recover costs or achieve anticipated returns, its financial condition, results of operations and cash flows could be adversely affected.

These initiatives may increase the significance of certain regulatory, permitting and approval-related risks discussed elsewhere in this Quarterly Report on Form 10-Q and in our 2025 Annual Report on Form 10-K.

Operational, market, environmental and public policy developments could adversely affect the Google data center project and its expected benefits.

We will rely on the successful operation of dedicated generation facilities, transmission infrastructure and a privately managed microgrid structure to serve the Google project. Operational failures, fuel supply disruptions, cyber incidents, transmission constraints, third-party resource performance issues, reliability events or other interruptions could adversely affect the Company's ability to satisfy its contractual obligations and realize anticipated economic benefits.

In addition, the project may be affected by evolving environmental regulations, energy policies and stakeholder expectations. We may face opposition from community groups, environmental organizations, governmental entities or other stakeholders relating to data center development, transmission expansion, natural gas-fired generation, greenhouse gas emissions, water usage or other environmental and land use considerations. Increased regulatory scrutiny, permitting challenges, litigation, adverse publicity or policy changes could delay project development, increase project costs, limit future expansion opportunities or otherwise adversely affect the expected benefits of the project.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table contains monthly information about our acquisitions of equity securities for the three months ended September 30, 2026:

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
July 1, 2026 - July 31, 2026	1	$ 73.68	—	—
August 1, 2026 - August 31, 2026	559	72.15	—	—
September 1, 2026 - September 30, 2026	1	72.39	—	—
Total	561	$ 72.15	—	—

(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 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.

ITEM 5. 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 September 30, 2026.

ITEM 6. 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
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.
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 Linkbase Documents
104*	Cover Page Interactive Data File (formatted as inline XBRL and contained in Exhibit 101)

SIGNATURES

Pursuant to the requirements 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

/s/ Linden R. Evans

Linden R. Evans, President and
Chief Executive Officer

/s/ Kimberly F. Nooney

Kimberly F. Nooney, Senior Vice President and
Chief Financial Officer

Dated: November 5, 2026

Exhibit 31.1

CERTIFICATION

I, Linden R. Evans, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q 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: November 5, 2026

/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 Quarterly Report on Form 10-Q 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: November 5, 2026

/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 Quarterly Report of Black Hills Corporation (the "Company") on Form 10-Q for the period ended September 30, 2026, 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: November 5, 2026

/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 Quarterly Report of Black Hills Corporation (the "Company") on Form 10-Q for the period ended September 30, 2026, 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: November 5, 2026

/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 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 three month period ended September 30, 2026. 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 Wyodak Mine under the indicated provisions of the Mine Act, together with the total dollar value of proposed MSHA assessments received during the three months ended September 30, 2026, and legal actions pending before the Federal Mine Safety and Health Review Commission (FMSHRC), together with the Administrative Law Judges thereof, for 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 three months ended September 30, 2026	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 Mine - 4800083	0	0	0	0	0	$ 302	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.