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To date, we have experienced limited impacts to our results of operations, financial condition, cash flows or business plans. However, the situation remains fluid and it is difficult to predict with certainty the potential impact of COVID-19 on our results of operations, financial condition and cash flows.

## ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

## ITEM 3. LEGAL PROCEEDINGS

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

## ITEM 4. MINE SAFETY DISCLOSURES

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

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## INFORMATION ABOUT OUR EXECUTIVE OFFICERS

**Linden R. Evans,** age 58, has been President and Chief Executive Officer since January 1, 2019, President and Chief Operating Officer from 2016 through 2018, and President and Chief Operating Officer — Utilities from 2004 through 2015. Mr. Evans served as the Vice President and General Manager of our former communication subsidiary in 2003 and 2004, and Associate Counsel from 2001 to 2003. Mr. Evans has 19 years of experience with the Company.

**Scott A. Buchholz,** age 59, has been our Senior Vice President of Strategic Initiatives since July 2020. He served as Senior Vice President — Chief Information Officer from the closing of the Aquila Transaction in 2008 to 2020. Prior to joining the Company, he was Aquila's Vice President of Information Technology from 2005 until 2008, Six Sigma Deployment Leader/Black Belt from 2004 until 2005, and General Manager, Corporate Information Technology from 2002 until 2004. Mr. Buchholz has 40 years of experience with the Company, including 28 years with Aquila. Mr. Buchholz plans to retire on March 8, 2021.

**Brian G. Iverson,** age 58, has been Senior Vice President, General Counsel and Chief Compliance Officer since August 26, 2019. He served as Senior Vice President, General Counsel, Chief Compliance Officer and Corporate Secretary from February 1, 2019 to August 26, 2019, Senior Vice President, General Counsel and Chief Compliance Officer from 2016 to February 2019, Senior Vice President - Regulatory and Governmental Affairs and Assistant General Counsel from 2014 to 2016, Vice President and Treasurer from 2011 to 2014, Vice President - Electric Regulatory Services from 2008 to 2011 and as Corporate Counsel from 2004 to 2008. Mr. Iverson has 17 years of experience with the Company.

**Richard W. Kinzley,** age 55, has been Senior Vice President and Chief Financial Officer since 2015. He served as Vice President - Corporate Controller from 2013 to 2014, Vice President - Strategic Planning and Development from 2008 to 2013, and as Director of Corporate Development from 2000 to 2008. Mr. Kinzley has 21 years of experience with the Company.

**Jennifer C. Landis,** age 46, has been Senior Vice President - Chief Human Resources Officer since February 1, 2017. She served as Vice President of Human Resources from April 2016 through January 2017, Director of Corporate Human Resources and Talent Management from 2013 to April 2016, and Director of Organization Development from 2008 to 2013. Ms. Landis has 19 years of experience with the Company.

**Stuart Wevik,** age 59, has been Senior Vice President - Utility Operations since August 26, 2019. He served as Group Vice President - Electric Utilities from 2016 to August 2019, Vice President - Utility Operations from 2008 to 2016, Vice President - Operations from 2004 to 2008 and Vice President and General Manager from 2003 to 2004. Mr. Wevik has 35 years of experience with the Company.

**Erik Keller**, age 57, joined the Company as Senior Vice President and Chief Information Officer on July 27, 2020. Prior to joining the company, he was an Information Technology consultant to Ontic Inc., a global provider of parts and services for legacy aerospace platforms, from January 2020 to July 2020, and Chief Information Officer for BBA Aviation, a global aviation support and aftermarket services provider, from February 2012 to January 2020.

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## PART II

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

Our common stock is traded on the New York Stock Exchange under the symbol BKH. As of January 31, 2021, we had 3,537 common shareholders of record and 46,737 beneficial owners, representing all 50 states, the District of Columbia and 6 foreign countries.

We have paid a regular quarterly cash dividend each year since the incorporation of our predecessor company in 1941 and expect to continue paying a regular quarterly dividend for the foreseeable future. At its January 27, 2021 meeting, our Board of Directors declared a quarterly dividend of $0.565 per share, equivalent to an annual dividend rate of $2.26 per share. This equivalent rate, if declared and paid in 2021, will represent 51 consecutive years of annual dividend increases.

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

### UNREGISTERED SECURITIES ISSUED

There were no unregistered securities sold during 2020.

### ISSUER PURCHASES OF EQUITY SECURITIES

The following table contains monthly information about our acquisitions of equity securities for the three months ended December 31, 2020:

| Period | Total Number of Shares Purchased [(a)] | Average Price Paid per Share | Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs | Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs |
|---|---|---|---|---|
| October 1, 2020 - October 31, 2020 | 1 | $ 53.95 | — | — |
| November 1, 2020 - November 30, 2020 | 804 | 58.63 | — | — |
| December 1, 2020 - December 31, 2020 | 7,569 | 59.66 | — | — |
| Total | 8,374 | $ 59.56 | — | — |

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

## ITEM 6. SELECTED FINANCIAL DATA

*We have early adopted the new SEC amendments to modernize, simplify, and enhance certain financial disclosure requirements in Regulation S-K which, among other things, eliminates the requirement to present Selected Financial Data.*

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

### Executive Summary

We are a customer-focused, growth-oriented electric and natural gas utility company with a mission of Improving Life with Energy and a vision to be the Energy Partner of Choice. The Company provides electric and natural gas utility service to 1.3 million customers over 800 communities in eight states, including Arkansas, Colorado, Iowa, Kansas, Montana, Nebraska, South Dakota and Wyoming. We conduct our business operations through four reportable segments: Electric Utilities, Gas Utilities, Power Generation and Mining. Certain unallocated corporate expenses that support our operating segments are presented as Corporate and Other. The Company conducts its utility operations under the name Black Hills Energy predominantly in rural areas of the Rocky Mountains and Midwestern states. The Company's Electric Utilities are supported by our Power Generation and Mining segments, which are mostly contracted to company affiliates and subject to utility-like regulation and oversight. The Power Generation segment produces electric power from its five generating facilities and sells most of the electric capacity and energy to our Electric Utilities under mid- and long-term contracts. The Mining segment, consisting of a single coal mine near Gillette, Wyoming, sells nearly all production to fuel the five on-site, mine-mouth power generation facilities. With more than 90% of the Company's assets directly invested in its regulated utility businesses and the Power Generation and Mining segments supporting its electric utilities mainly through long-term contracts, the Company considers itself a domestic, pure-play electric and natural gas utility company.

The Company has provided energy and served customers for 137 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. Our strategic focus has not changed in over a century - serving customers with affordable, reliable and safe energy and being strong environmental stewards. Our strategy today continues that emphasis on serving customers and being responsive to the people and communities we serve. Customer expectations are rapidly changing with the advancement of technology and customers are demanding simpler, faster and more convenient solutions to their energy needs. Customers and other stakeholders are demanding cleaner energy solutions to address concerns around carbon emissions. In this rapidly changing energy environment, we are *Ready* to serve.

Our strategy focuses on improving the way we serve customers with safe, reliable, affordable and cleaner energy while improving the lives of the customers and communities we serve. Our emphasis is on consistently outperforming utility industry averages in key safety metrics; transforming the customer experience; growing our electric and natural gas customer load; pursuing operating efficiencies; and modernizing utility infrastructure. These areas of focus will present the company with significant investment needs as we modernize our infrastructure systems, meet customer growth and fulfill customer expectations for cleaner energy services. It will also allow us to better understand our customer and community needs while providing more intuitive and cost-effective interactions.

### Key Elements of our Business Strategy

***Modernize, replace and operate utility infrastructure to meet our customers' energy needs while providing safe, reliable, affordable and cleaner energy.*** Our utilities own and operate large electric and natural gas infrastructure systems with a geographic footprint that spans nearly 1,600 miles of the United States. Our Electric Utilities own and operate 992 MW of generation capacity and 8,900 miles of transmission and distribution lines and our Gas Utilities own and operate 47,000 miles of natural gas transmission and distribution pipelines. A key strategic focus is to modernize this utility infrastructure to meet customers' and communities' varied energy needs, ensure the continued delivery of safe, reliable and affordable energy and reduce GHG emission intensity. In addition, we invest in the accessibility, capacity and integrity of our systems to meet customer growth.

We rigorously comply with all applicable federal, state and local regulations and strive to consistently meet industry best practice standards. A key component of our modernization effort is the development of programs by our Electric and Gas Utilities to systematically and proactively replace aging infrastructure on a system-wide basis. To meet our electric customers' continued expectations of high levels of reliability, our Electric Utilities utilize a distribution integrity program to ensure the timely repair and replacement of aging infrastructure. Our Gas Utilities utilize a programmatic approach to system-wide pipeline replacement, particularly in high consequence areas. Under the programmatic approach, obsolete, at-risk and vintage materials are replaced in a proactive and systematic time frame. We have removed all cast- and wrought-iron from our natural gas transmission and distribution systems and continue to replace aging infrastructure through programs that prioritize safety and reliability for our customers. All but one of our Gas Utilities are authorized to use system safety, integrity and replacement cost recovery mechanisms that provide for customer rate adjustments which reflect the cost incurred in repairing and replacing the gas delivery systems.

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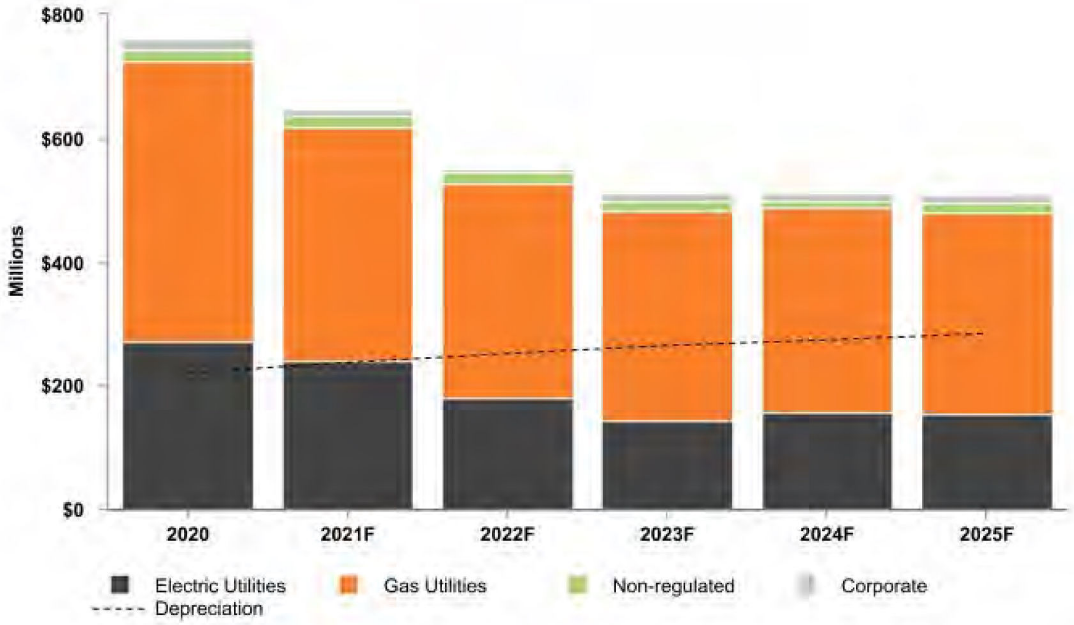
As of December 31, 2020, we estimate our five-year capital investment to be approximately $2.7 billion, with most of that investment targeted toward upgrading existing utility infrastructure and to support customer and community growth needs. Our actual 2020 and forecasted capital expenditures and depreciation for the next five years from 2021 through 2025 are as follows (in millions):




| Capital Expenditures By Segment[a] : | Actual 2020 | Forecasted 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| *(in millions)* | | | | | | |
| Electric Utilities | $ 271 | $ 240 | $ 180 | $ 143 | $ 156 | $ 154 |
| Gas Utilities | 449 | 377 | 347 | 339 | 330 | 326 |
| Power Generation | 9 | 10 | 9 | 6 | 4 | 5 |
| Mining | 8 | 9 | 9 | 9 | 9 | 10 |
| Corporate and Other | 18 | 11 | 5 | 13 | 13 | 13 |
| Total | $ 755 | $ 647 | $ 550 | $ 510 | $ 512 | $ 508 |

(a) Includes accruals for property, plant and equipment as disclosed as supplemental cash flow information in the Consolidated Statements of Cash Flows in the Consolidated Financial Statements in this Annual Report on Form 10-K.

***Efficiently plan, construct and operate rate base power generation facilities to serve our Electric Utilities.*** We believe that we best serve customers and communities with a vertically integrated business model for our Electric Utilities. This business model remains a core strength and strategy today as we invest in and operate efficient power generation resources to cost-effectively supply electricity to our customers. We strive to provide power at reasonable rates to our customers and earn competitive returns for our investors.

Our power production strategy focuses on low-cost construction and efficient operation of our generating facilities. Our low power production costs result from a variety of factors including low fuel costs, efficiency in converting fuel into energy, low per unit operating and maintenance costs and high levels of power plant availability. For our coal-fired power plants, we leverage our mine-mouth location advantage to eliminate coal transportation costs that often represent the largest component of the delivered cost of coal for many other utilities. Additionally, we operate our plants with high levels of availability as compared to industry benchmarks.

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We continue to believe that ownership of power generation facilities by our Electric Utilities best serves customers. Rate-based generation assets offer several advantages for customers and shareholders, including:

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

***Proactively integrate alternative and renewable energy into our utility energy supply while mitigating customer rate impacts.*** In November 2020, we announced clean energy goals to reduce GHG emissions intensity for our Electric Utilities of 40% by 2030 and 70% by 2040 and achieve GHG reductions of 50% by 2035 for our Gas Utilities. Our goals are based on existing technology and computed from 2005 baseline levels of GHG emissions intensity for our electric operations and natural gas distribution system. Since 2005, we have reduced GHG emissions intensity from our Gas Utilities by more than 33% and achieved a 25% reduction from our Electric Utilities. Colorado Electric has achieved an approximate 50% reduction in GHG emissions since 2005 and is on track to reach Colorado's 80% carbon reduction goal by 2030. Our goals are based on prudent and proven solutions to reduce our emissions while minimizing cost impacts to our customers. This keeps our customers at the forefront of our decision-making, which is central to our values.

More of our customers, particularly our larger customers, are demanding cleaner sources of energy to meet their sustainability goals. In addition, there is more interest from consumers, regulators and legislators to increase the use of renewable and other alternative energy sources. To support this interest, we created the Renewable Ready program for South Dakota and Wyoming customers. In support of this program, we created and received approvals for new, voluntary renewable energy tariffs to serve certain commercial, industrial and governmental agency customer requests for renewable energy resources. To meet the renewable energy commitments under the new tariffs, on November 30, 2020, we completed construction and placed into service the Corriedale wind project, a 52.5 MW wind energy project near Cheyenne, Wyoming. Supporting our renewable energy efforts in Colorado, in September 2020, Colorado Electric received approval from the CPUC for its request for approval of its preferred solar bid in support of its Renewable Advantage program, which plans to add up to 200 MW of renewable energy by the end of 2023.

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

***Build and maintain strong relationships with wholesale power customers of our utilities and our power generation business***. We strive to build strong relationships with other utilities, municipalities and wholesale customers. We believe we will continue to be an important provider of electricity to wholesale utility customers, who will continue to need products such as capacity and energy to reliably serve their customers. By providing these products under long-term contracts, we help our customers meet their energy needs. We also earn more stable revenues and greater returns for shareholders over the long-term than we would by selling energy into more volatile energy spot markets. In addition, relationships that we have established with wholesale power customers have developed into other opportunities. MEAN, MDU and the City of Gillette, Wyoming were wholesale power customers that are now joint minority owners in two of our power plants, Wygen I and Wygen III, reducing risk and providing steady revenues.

***Vertically integrate businesses that are supportive of our Electric and Gas Utility businesses.*** While our primary focus is serving customers and growing our core utilities, we selectively invest in vertically integrated businesses that provide cost effective and efficient fuel and energy to our utilities. We currently own and operate power generation and mining assets that are vertically integrated into and support our Electric Utilities. These operations are located at our utility-generating complexes and are physically integrated into our Electric Utilities' operations.

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The Power Generation segment currently owns five power facilities, four of which are contracted with our affiliate Electric Utilities under mid- to long-term power purchase agreements. Our Power Generation segment has an experienced staff with significant expertise in planning, building and operating power plants. The power generation team has constructed 22 generation projects since 1995 with an aggregate investment in excess of $2.5 billion. This team also provides shared services to our Electric Utilities' generation facilities, resulting in efficient management of all of the company's generation assets. In certain states, our Electric Utilities are required to competitively bid for generation resources needed to serve customers. Generally, our Power Generation segment submits bids in response to those competitive solicitations. Our Power Generation segment can often realize competitive advantages provided by prior construction expertise, fuel supply advantages and by co-locating new plants at existing sites, reducing infrastructure and operating costs.

Our small surface coal mine is located immediately adjacent to our Gillette energy complex in northeastern Wyoming, where all five of our remaining coal-fired power plants are located. We operate and own majority interests in four of the five power plants. We own 20% of the fifth power plant which is operated by a majority owner. The mine provides low-sulfur coal directly to these power plants via a conveyor belt system, minimizing transportation costs. On average, the fuel can be delivered to the adjacent power plants at less than $1.00 per MMBtu, providing very cost competitive fuel to our power plants when compared to other coal-fired and natural gas-fired generating facilities. Nearly all of the mine's production is sold to the five on-site, mine-mouth generation facilities under long-term supply contracts. Approximately one-half of our production is sold under cost-plus contracts with affiliates. A small portion of the mine's production is sold to off-site industrial customers and delivered by truck.

***Grow our dividend.*** We are extremely proud of our track record of annual dividend increases for shareholders. 2020 represented our 50th consecutive year of increasing dividends. In January 2021, our Board of Directors declared a quarterly dividend of $0.565 per share, equivalent to an annual dividend of $2.26 per share. We intend to continue our record of annual dividend increases with a targeted dividend payout ratio of 50% to 60%.

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

## Prospective Information

We expect to generate long-term growth through the expansion of integrated utilities and supporting operations. Sustained growth requires continued capital deployment. Our integrated energy portfolio, focused predominately on regulated utilities, provides growth opportunities, yet avoids concentrating business risk. We expect much of our earnings growth in the next few years will come from the need for capital deployment at our utilities and continued focus on improving efficiencies and controlling costs. Although dependent on market conditions, we are confident in our ability to obtain additional financing, as necessary, to continue our growth plans. We remain focused on prudently managing our operations and maintaining our overall liquidity to meet our operating, capital and financing needs, as well as executing our long-term strategic plan. Prospective information for our operating segments should be read in conjunction with our business strategy discussed above, and our company highlights discussed below.

## Company Highlights

### February 2021 Weather Event

In February 2021, a prolonged period of historic cold temperatures across the central United States, which covered all of our Utilities' service territories, caused a significant increase in heating and energy demand and contributed to unforeseeable and unprecedented market prices for natural gas and electricity. Although this historic weather and energy demand event strained energy resources across the United States, our natural gas and electric systems performed as expected and demonstrated our *Ready to Serve* commitment to our customers. Our ongoing system investments in safety and reliability and our strong operational performance were essential in our ability to maintain service for our customers during this extraordinary event.

We responded to this event with requests for certain natural gas customer usage curtailments that began on February 12, 2021, and extended through February 19, 2021, to ensure the reliability of our system. We also communicated to all customers on how to conserve energy and stay safe during this event. Our customer service representatives worked extended hours to provide guidance and support to our customers.

Our Utilities have regulatory mechanisms to recover the increased energy costs from this record-breaking cold weather event. However, given the extraordinary impact of these higher costs to our customers, we expect our regulators to undertake a heightened review. We are engaged with our regulators to identify appropriate recovery periods over which to recover costs associated with this event as we continue to address the impacts to our customers' bills.

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As a result of this historic event, our natural gas purchases increased by approximately $600 million compared to forecasted base load for the month of February. This amount is a preliminary estimate through February 24, 2021, and does not include certain pipeline transportation charges that remain subject to settlement and are payable in late March 2021. To fund February natural gas purchases and pipeline transportation charges and provide additional liquidity, we entered into an $800 million term loan maturing on November 23, 2021. The nine-month term loan has no prepayment penalty and is subject to the same covenants as our Revolving Credit Facility. We expect to repay a portion of this term loan prior to maturity and refinance the remaining portion in longer-term debt.

As of February 24, 2021, the Company had $1.3 billion of liquidity consisting of approximately $800 million of cash and $500 million of available capacity on its Revolving Credit Facility.

**COVID-19 Pandemic**

One of the Company's core values is safety. The COVID-19 pandemic has given us an opportunity to demonstrate our commitment to the health and safety of our customers, employees, business partners and the communities we serve. We have executed our business continuity plans across all of our jurisdictions with the goal of continuing to provide safe and reliable service during the COVID-19 pandemic.

For the year ended December 31, 2020, we have experienced limited impacts to our financial results and operational activities due to COVID-19. Negative impacts to gross margins were driven primarily by lower volumes in certain commercial and industrial customers and waived customer late payment fees which were partially offset by higher residential usage. Increased operations and maintenance expenses due to sequestration costs of mission critical and essential employees and increased bad debt expense were partially offset by decreased training, travel, and outside services related expenses.

We continue to closely monitor customer loads in our states as updated executive orders and recommendations associated with COVID-19 are provided. We have continued to proactively communicate with various commercial and industrial customers in our service territories to understand their needs and forecast the potential financial implications. We have increased our allowance for credit losses and bad debt expense by $3.3 million for the year ended December 31, 2020, after considering the potential economic impact of the COVID-19 pandemic in forward looking projections related to write-off and recovery rates. All of our jurisdictions temporarily suspended disconnections for a period of time. State orders lifting those restrictions have been issued in nearly all of our jurisdictions; however, we expect the status of restrictions will continue to fluctuate for the next several months. We continue to monitor customer loads, accounts receivable arrears balances, disconnects, cash flows and bad debt expense. We are proactively working with customers to establish payment plans and find available payment assistance resources.

Throughout 2020, we maintained adequate liquidity to operate our businesses and fund our capital investment program. In February 2020, the Company issued $100 million in equity to support its 2020 capital investment program. In June 2020, the Company issued $400 million of long-term debt which was used to repay short-term debt and for working capital and general corporate purposes. For the year ended December 31, 2020, the Company also utilized a combination of its $750 million Revolving Credit Facility and CP Program to meet its funding requirements. As of December 31, 2020, the Company had $498 million of liquidity which included $6.4 million of cash and $491 million of available capacity on its Revolving Credit Facility. We continue to meet our debt covenant requirements. We also continue to monitor the funding status of our employee benefit plan obligations, which did not materially change during the year ended December 31, 2020.

We are monitoring supply chains, including lead times for key materials and supplies, availability of resources, and status of large capital projects. To date, there have been limited impacts from COVID-19 on supply chains including the availability of supplies, materials and lead times. Capital projects are ongoing without material disruption to schedules due to COVID-19. Our third party resources continue to support our business plans without disruption. Contingency plans are ready to be executed if significant disruption to supply chain occurs; however, we currently do not anticipate a significant impact from COVID-19 on our capital investment plan for 2021.

We continue to work closely with local health, public safety and government officials to minimize the spread of COVID-19 and its impact to our employees and the services we provide to our customers. Actions the Company took earlier in the year included implementing protocols for our field operations personnel to safely and effectively interact with our customers, asking certain employees to work from home, requiring employees to complete daily health assessments, covering 100% of COVID-19 testing costs for our active employee medical plans, limiting travel to only mission-critical purposes and temporarily sequestering essential employees.

During the third quarter of 2020, we suspended sequestration of essential employees but continued to monitor the impacts of COVID-19 in our service territories to ensure we provide reliable service to our customers. Additionally, we implemented our *Ready2Return* program, which includes a phased return of our employees to our work facilities while keeping our workforce healthy, safe and informed. Our *Ready2Return* program also focuses on enhancing our facility readiness to improve ventilation, ensure social distancing and establish cleaning services to reduce the spread of infection.

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On January 13, 2021, the FERC sent a letter to the Centers for Disease Control and Prevention's (CDC) Advisory Committee on Immunization Practices urging that essential employees of the energy workforce receive vaccines earlier than currently recommended. We continue to monitor guidance from the CDC to ensure our essential employees may receive the vaccine within a prioritized phase.

We provide periodic status updates and maintain ongoing dialogue with the regulatory commissions in our jurisdictions. We have worked with regulators in our service territories to preserve our right for deferred regulatory treatment for certain COVID-19 related costs and to seek recovery of these costs at a later date.

During these uncertain times, we remain highly focused on the safety and health of our customers, employees, business partners and communities. We continue to monitor load, customers' ability to pay, the potential for supply chain disruption that may impact our capital and maintenance project plans, the availability of resources to execute our plans and the capital markets to ensure we have the liquidity necessary to support our financial needs.

As we look forward to 2021 and beyond, our operating results could be further affected by COVID-19, as discussed in detail in our Risk Factors.

**Business Segment Highlights and Corporate Activity**

Electric Utilities

- On November 30, 2020, South Dakota Electric and Wyoming Electric completed and placed in service the Corriedale project. The 52.5 MW wind project is jointly owned by the two electric utilities to deliver renewable energy for large commercial, industrial and governmental agency customers under the Renewable Ready program.
- On October 15, 2020, the FERC approved a settlement agreement in the joint application filed by Wyoming Electric and Black Hills Wyoming on August 2, 2019 for approval of a new 60 MW PPA. Under terms of the settlement, Wyoming Electric will continue to receive 60 MW of capacity and energy from the Wygen I power plant. The new agreement will commence on January 1, 2022, replace the existing PPA and continue for 11 years.
- On September 23, 2020, Colorado Electric received approval from the CPUC for its request for approval of its preferred solar bid in support of its Renewable Advantage program. The program plans to add up to 200 MW of renewable energy in Colorado by the end of 2023.
- On July 10, 2020, Wyoming Electric set a new all-time peak load of 271 MW, surpassing the previous peak of 265 MW set in July 2019.
- On May 5, 2020, citizens in Pueblo, Colorado voted overwhelmingly to retain Colorado Electric as its electric utility provider by 75.6% of votes cast. The current franchise agreement continues through 2030.

Gas Utilities

- On January 26, 2021, Nebraska Gas received approval from the NPSC to consolidate rate schedules into a new, single statewide structure and recover significant infrastructure investments in its 13,000-mile natural gas pipeline system. Final rates will be enacted on March 1, 2021 and is expected to generate $6.5 million in new annual revenue with a capital structure of 50% equity and 50% debt and a return on equity of 9.5%. The approval also includes an extension of the SSIR for five years and an expansion of this mechanism for consolidated utility alignment.
- On September 11, 2020, Colorado Gas filed a rate review with the CPUC seeking recovery on significant infrastructure investments in its 7,000-mile natural gas pipeline system. The rate review requests $13.5 million in new annual revenue with a capital structure of 50% equity and 50% debt and a return on equity of 9.95%. The request seeks to implement new rates in the second quarter of 2021. On January 6, 2021 the CPUC issued an order dismissing the rate review. On January 26, 2021, Colorado Gas filed an application for rehearing, reargument or reconsideration in response to the Commission's January 6 order.

  On September 11, 2020, in accordance with the final order from the earlier rate review discussed below, Colorado Gas also filed a new SSIR proposal that would recover safety and integrity focused investments in its system over five years. A decision from the CPUC is expected by mid-2021.
- On December 27, 2020, gas service to approximately 3,500 Colorado Gas customers in Aspen, Colorado was disrupted due to vandalism. Gas services were restored to nearly all customers by December 30, 2020 with the remaining few restored by January 1, 2021. Colorado Gas employees were joined by Black Hills Energy technicians from other states, as well as contractors and other utilities, to successfully restore service despite challenging weather, temperatures, additional precautions due to COVID-19 and significant travel by many to reach Aspen.

- On February 1, 2019, Colorado Gas filed a rate review with the CPUC requesting $2.5 million in new revenue to recover investments in safety, reliability and system integrity and approval to consolidate rates, tariffs, and services of its two existing gas distribution territories. Colorado Gas also requested a new rider mechanism to recover future safety and integrity investments in its system. On May 19, 2020, the CPUC issued a final order which denied the new system integrity recovery mechanism and consolidation of rate territories. In addition, the order resulted in an annual revenue decrease of $0.6 million and a return on equity of 9.2%. New rates were effective July 3, 2020.

- On March 1, 2020, Wyoming Gas enacted new rates and implemented a new rider to recover integrity investments. The new, single statewide rate structure successfully completed the consolidation process of four natural gas utilities in the state and is expected to generate $13 million in new annual revenues. Going forward, the new rate structure and consolidated tariffs will contribute to improvements in customer service and reduce the complexity and number of rate reviews and other regulatory filings.

Power Generation

- On October 15, 2020, the FERC approved a settlement agreement in the joint application filed by Black Hills Wyoming and Wyoming Electric on August 2, 2019 for approval of a new 60 MW PPA. See additional information in the Electric Utilities Segment highlights above.

Corporate and Other

- On August 3, 2020, we filed a shelf registration and DRSPP with the SEC. In conjunction with these shelf filings, we renewed the ATM. The renewed ATM program, which allows us to sell shares of our common stock, is the same as the prior program other than the aggregate value increased from $300 million to $400 million and a forward sales option was incorporated. This forward sales option allows us to sell our shares through the ATM program at the current trading price without actually issuing any shares to satisfy the sale until a future date.

- On June 17, 2020, we completed a public debt offering of $400 million principal amount in senior unsecured notes. The debt offering consisted of $400 million of 2.50%, 10-year senior notes due June 15, 2030. The proceeds were used to repay short-term debt, as well as for working capital and general corporate purposes.

- On February 27, 2020, we issued 1.2 million shares of common stock at a price of $81.77 per share for net proceeds of $99 million.

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## Results of Operations

*Our discussion and analysis for the year ended December 31, 2020 compared to 2019 is included herein. For discussion and analysis for the year ended December 31, 2019 compared to 2018, please refer to Item 7 of Part II, "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report on Form 10-K for the year ended December 31, 2019, which was filed with the SEC on February 14, 2020.*

*Segment information does not include intercompany eliminations and all amounts are presented on a pre-tax basis unless otherwise indicated. Per share information references diluted shares unless otherwise noted.*

**Consolidated Summary and Overview**

| | For the Years Ended December 31, 2020 | 2019 | 2018 |
|---|---|---|---|
| | (in thousands) | | |
| Adjusted operating income [a] : | | | |
| Electric Utilities | $ 156,055 | $ 160,297 | $ 155,869 |
| Gas Utilities | 215,889 | 189,971 | 185,239 |
| Power Generation | 42,112 | 44,779 | 42,614 |
| Mining | 12,807 | 12,627 | 16,340 |
| Corporate and Other | 1,440 | (1,632) | (3,025) |
| Operating Income | 428,303 | 406,042 | 397,037 |
| | | | |
| Interest expense, net | (143,470) | (137,659) | (139,975) |
| Impairment of investment | (6,859) | (19,741) | — |
| Other income (expense), net | (2,293) | (5,740) | (1,180) |
| Income tax benefit (expense) | (32,918) | (29,580) | 23,667 |
| Income from continuing operations | 242,763 | 213,322 | 279,549 |
| (Loss) from discontinued operations, net of tax | — | — | (6,887) |
| Net income | 242,763 | 213,322 | 272,662 |
| Net income attributable to noncontrolling interest | (15,155) | (14,012) | (14,220) |
| Net income available for common stock | $ 227,608 | $ 199,310 | $ 258,442 |
| | | | |
| Earnings per share from continuing operations, Diluted | $ 3.65 | $ 3.28 | $ 4.78 |
| (Loss) per share from discontinued operations, Diluted | — | — | (0.12) |
| Total earnings per share of common stock, Diluted | $ 3.65 | $ 3.28 | $ 4.66 |

(a) Adjusted operating income recognizes intersegment revenues and costs for Colorado Electric's PPA with Black Hills Colorado IPP on an accrual basis rather than as a finance lease. This presentation of segment information does not impact consolidated financial results.

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**2020 Compared to 2019**

The variance to the prior year included the following:

- COVID-19 related impacts to consolidated results included $3.6 million of lower gross margin driven primarily by lower volumes and waived customer late payment fees, $2.6 million of costs due to sequestration of essential employees and $3.3 million of additional bad debt expense which were partially offset by $3.8 million of lower travel, training, and outside services related expenses;
- Electric Utilities' adjusted operating income decreased $4.2 million due to higher depreciation and amortization expense as a result of additional plant placed in service, lower commercial and industrial demand and COVID-19 impacts partially offset by benefits from the release of TCJA revenue reserves and increased rider revenues;
- Gas Utilities' adjusted operating income increased $26 million primarily due to new customer rates in Wyoming and Nebraska and increased rider revenues, customer growth, mark-to-market gains on non-utility natural gas commodity contracts and prior year amortization of excess deferred income taxes partially offset by higher depreciation and amortization expense as a result of additional plant placed in service, COVID-19 impacts and unfavorable weather;
- Power Generation's adjusted operating income decreased $2.7 million primarily due to higher depreciation and maintenance expense from new wind assets and expense related to the early retirement of certain assets;
- Corporate and Other expenses decreased $3.1 million primarily due to lower unallocated employee costs;
- A $6.9 million pre-tax non-cash impairment in 2020 of our investment in equity securities of a privately held oil and gas company compared to a similar $20 million impairment in 2019;
- Interest expense increased $5.8 million primarily due to higher debt balances partially offset by lower rates;
- Other expense decreased $3.4 million due to the prior year expensing of $5.4 million of development costs related to projects we no longer intend to construct partially offset by increased current year pension non-service costs; and
- Increased tax expense of $3.3 million primarily due to higher pre-tax income partially offset by a lower effective tax rate.

**Segment Operating Results**

A discussion of operating results from our business segments follows.

***Non-GAAP Financial Measure***

The following discussion includes financial information prepared in accordance with GAAP, as well as another financial measure, gross margin, that is considered a "non-GAAP financial measure." Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. Gross margin (revenue less cost of sales) is a non-GAAP financial measure due to the exclusion of depreciation and amortization from the measure. The presentation of gross margin is intended to supplement investors' understanding of our operating performance.

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

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

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**Electric Utilities**

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

| | 2020 | Variance | 2019 | Variance | 2018 |
|---|---|---|---|---|---|
| Revenue | $ 714,044 | $ 1,292 | $ 712,752 | $ 1,301 | $ 711,451 |
| Total fuel and purchased power | 267,045 | (1,252) | 268,297 | (15,543) | 283,840 |
| Gross margin (non-GAAP) | 446,999 | 2,544 | 444,455 | 16,844 | 427,611 |
| Operations and maintenance | 196,794 | 1,213 | 195,581 | 9,406 | 186,175 |
| Depreciation and amortization | 94,150 | 5,573 | 88,577 | 3,010 | 85,567 |
| Total operating expenses | 290,944 | 6,786 | 284,158 | 12,416 | 271,742 |
| Adjusted operating income | $ 156,055 | $ (4,242) | $ 160,297 | $ 4,428 | $ 155,869 |

2020 Compared to 2019

Gross margin increased over the prior year as a result of:

| | (in millions) |
|---|---|
| Release of TCJA revenue reserves [(a)] | $ 2.7 |
| Rider recovery and true-up [(b)] | 2.3 |
| Transmission services | 1.4 |
| Residential customer growth | 0.9 |
| Lower commercial and industrial demand | (2.7) |
| COVID-19 impacts [(c)] | (1.8) |
| Weather | (0.3) |
| Total increase in Gross margin (non-GAAP) | $ 2.5 |

(a) In July 2020, regulatory proceedings resolved the last of the Company's open dockets seeking approval of its TCJA plans. As a result, the Company reversed certain TCJA-related liabilities, which resulted in an increase to Gross margin of $2.7 million. See Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional details.
(b) Gross margin increased due to $3.5 million of rider revenues, which was partially offset by a $1.2 million rider true-up.
(c) The impacts to Electric Utilities' gross margin from COVID-19 were primarily driven by reduced commercial volumes and waived customer late payment fees partially offset by higher residential usage.

Operations and maintenance expense increased primarily due to COVID-19 impacts which included $2.2 million of expenses related to the sequestration of essential employees and $0.8 million of additional bad debt expense which were partially offset by $1.2 million of lower travel, training and outside services related expenses. Additionally, lower employee costs of $1.9 million were partially offset by $1.0 million of higher property taxes due to a higher asset base driven by prior and current year capital expenditures.

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

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*Operating Statistics*

| | Electric Revenue (in thousands) | | | Quantities Sold (MWh) | | |
|---|---|---|---|---|---|---|
| For the year ended December 31, | 2020 | 2019 | 2018 | 2020 | 2019 | 2018 |
| Residential | $ 221,530 | $ 216,108 | $ 218,558 | 1,477,514 | 1,440,551 | 1,450,585 |
| Commercial | 239,166 | 246,704 | 250,894 | 1,974,043 | 2,055,253 | 2,034,917 |
| Industrial | 131,154 | 131,831 | 124,668 | 1,794,795 | 1,787,412 | 1,682,074 |
| Municipal | 16,860 | 17,206 | 17,871 | 158,222 | 157,298 | 160,913 |
| Subtotal Retail Revenue - Electric | 608,710 | 611,849 | 611,991 | 5,404,574 | 5,440,514 | 5,328,489 |
| Contract Wholesale [(a)] | 17,847 | 19,078 | 33,688 | 492,637 | 368,360 | 900,854 |
| Off-system/Power Marketing Wholesale | 24,308 | 25,622 | 24,800 | 648,928 | 701,633 | 673,994 |
| Other | 63,179 | 56,203 | 40,972 | — | — | — |
| Total Revenue and Energy Sold | 714,044 | 712,752 | 711,451 | 6,546,139 | 6,510,507 | 6,903,337 |
| Other Uses, Losses or Generation, net [(b)] | — | — | — | 400,826 | 393,573 | 470,250 |
| Total Revenue and Energy | 714,044 | 712,752 | 711,451 | 6,946,965 | 6,904,080 | 7,373,587 |
| Less cost of fuel and purchased power | 267,045 | 268,297 | 283,840 | | | |
| Gross Margin (non-GAAP) | $ 446,999 | $ 444,455 | $ 427,611 | | | |

| | Electric Revenue (in thousands) | | | Gross Margin (non-GAAP) (in thousands) | | | Quantities Sold (MWh) [(b)] | | |
|---|---|---|---|---|---|---|---|---|---|
| For the year ended December 31, | 2020 | 2019 | 2018 | 2020 | 2019 | 2018 | 2020 | 2019 | 2018 |
| Colorado Electric | $ 253,229 | $ 247,332 | $ 251,218 | $ 139,731 | $ 137,323 | $ 138,901 | 2,379,866 | 2,180,985 | 2,151,918 |
| South Dakota Electric [(a)] | 283,153 | 291,219 | 298,080 | 220,456 | 218,104 | 205,194 | 2,563,387 | 2,798,887 | 3,360,396 |
| Wyoming Electric | 177,662 | 174,201 | 162,153 | 86,812 | 89,028 | 83,516 | 2,003,712 | 1,924,208 | 1,861,273 |
| Total Revenue, Gross Margin (non-GAAP), and Quantities Sold | $ 714,044 | $ 712,752 | $ 711,451 | $ 446,999 | $ 444,455 | $ 427,611 | 6,946,965 | 6,904,080 | 7,373,587 |

(a) 2020 and 2019 revenue and purchased power, as well as associated quantities, for certain wholesale contracts have been presented on a net basis. 2018 amounts were presented on a gross basis and, due to their immaterial nature, were not revised. This presentation change has no impact on Gross margin.
(b) Includes company uses, line losses, and excess exchange production.

| | For the year ended December 31, | | |
|---|---|---|---|
| Quantities Generated and Purchased by Fuel Type (MWh) | 2020 | 2019 | 2018 |
| Generated: | | | |
| Coal | 2,273,635 | 2,226,028 | 2,368,506 |
| Natural Gas and Oil | 581,554 | 600,002 | 446,373 |
| Wind | 261,400 | 238,999 | 253,180 |
| Total Generated | 3,116,589 | 3,065,029 | 3,068,059 |
| Purchased: | | | |
| Coal, Natural Gas, Oil and Other Market Purchases [(a)] | 3,235,086 | 3,576,394 | 4,134,145 |
| Wind | 595,290 | 262,657 | 171,383 |
| Total Purchased | 3,830,376 | 3,839,051 | 4,305,528 |
| Total Generated and Purchased | 6,946,965 | 6,904,080 | 7,373,587 |

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| Quantities Generated and Purchased (MWh) | For the year ended December 31, 2020 | 2019 | 2018 |
|---|---|---|---|
| Generated: | | | |
| Colorado Electric | 364,058 | 443,770 | 481,446 |
| South Dakota Electric | 1,901,009 | 1,768,456 | 1,734,222 |
| Wyoming Electric | 851,522 | 852,803 | 852,391 |
| Total Generated | 3,116,589 | 3,065,029 | 3,068,059 |
| Purchased: | | | |
| Colorado Electric | 2,015,808 | 1,737,215 | 1,670,472 |
| South Dakota Electric [(a)] | 662,378 | 1,030,431 | 1,626,174 |
| Wyoming Electric | 1,152,190 | 1,071,405 | 1,008,882 |
| Total Purchased | 3,830,376 | 3,839,051 | 4,305,528 |
| Total Generated and Purchased | 6,946,965 | 6,904,080 | 7,373,587 |

(a) 2020 and 2019 purchased power quantities for a wholesale contract have been presented on a net basis. 2018 amounts were presented on a gross basis and, due to their immaterial nature, were not revised. This presentation change has no impact on Gross margin.

| Degree Days | For the year ended December 31, 2020 | | 2019 | | 2018 | |
|---|---|---|---|---|---|---|
| | Actual | Variance from Normal | Actual | Variance from Normal | Actual | Variance from Normal |
| Heating Degree Days: | | | | | | |
| Colorado Electric | 5,103 | (9)% | 5,453 | (3)% | 5,119 | 4% |
| South Dakota Electric | 6,910 | (3)% | 8,284 | 16% | 7,749 | 8% |
| Wyoming Electric | 6,771 | (5)% | 7,406 | 1% | 7,036 | (7)% |
| Combined [(a)] | 6,056 | (6)% | 6,813 | 5% | 6,405 | 3% |
| | | | | | | |
| Cooling Degree Days: | | | | | | |
| Colorado Electric | 1,384 | 54% | 1,226 | 37% | 1,420 | 58% |
| South Dakota Electric | 682 | 7% | 404 | (36)% | 488 | (23)% |
| Wyoming Electric | 594 | 71% | 462 | 33% | 430 | 24% |
| Combined [(a)] | 985 | 41% | 791 | 14% | 902 | 29% |

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

| Contracted generating facilities availability by fuel type[(a)] | For the year ended December 31, 2020 | 2019 | 2018 |
|---|---|---|---|
| Coal | 94.1% | 92.1% | 93.9% |
| Natural gas and diesel oil [(b)] | 80.6% | 87.9% | 96.4% |
| Wind | 98.1% | 95.6% | 96.9% |
| Total availability | 87.0% | 89.9% | 95.6% |
| | | | |
| Wind capacity factor | 38.9% | 38.7% | 39.2% |

(a) Availability and wind capacity factor are calculated using a weighted average based on capacity of our generating fleet.
(b) 2020 included a planned outage at Cheyenne Prairie and unplanned outages at Pueblo Airport Generation and Lange CT. 2019 included planned outages at Neil Simpson CT and Lange CT.

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**Gas Utilities**

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

| | 2020 | Variance | 2019 | Variance | 2018 |
|---|---|---|---|---|---|
| Revenue: | | | | | |
| Natural gas - regulated | $ 900,637 | $ (31,474) | $ 932,111 | $ (10,813) | $ 942,924 |
| Other - non-regulated services | 74,033 | (3,886) | 77,919 | (4,464) | 82,383 |
| Total revenue | 974,670 | (35,360) | 1,010,030 | (15,277) | 1,025,307 |
| | | | | | |
| Cost of natural gas sold: | | | | | |
| Natural gas - regulated | 347,611 | (59,032) | 406,643 | (35,887) | 442,530 |
| Other - non-regulated services | 7,034 | (12,221) | 19,255 | (368) | 19,623 |
| Total cost of sales | 354,645 | (71,253) | 425,898 | (36,255) | 462,153 |
| | | | | | |
| Gross margin (non-GAAP) | 620,025 | 35,893 | 584,132 | 20,978 | 563,154 |
| | | | | | |
| Operations and maintenance | 303,577 | 1,733 | 301,844 | 10,363 | 291,481 |
| Depreciation and amortization | 100,559 | 8,242 | 92,317 | 5,883 | 86,434 |
| Total operating expenses | 404,136 | 9,975 | 394,161 | 16,246 | 377,915 |
| | | | | | |
| Adjusted operating income | $ 215,889 | $ 25,918 | $ 189,971 | $ 4,732 | $ 185,239 |

2020 Compared to 2019

Gross margin increased over the prior year as a result of:

| | (in millions) |
|---|---|
| New rates | $ 25.4 |
| Customer growth - distribution | 5.6 |
| Mark-to-market on non-utility natural gas commodity contracts | 3.3 |
| Prior year amortization of excess deferred income taxes | 2.6 |
| Weather | (1.8) |
| COVID-19 impacts [a] | (1.8) |
| Other | 2.6 |
| Total increase in Gross margin (non-GAAP) | $ 35.9 |

(a) The impacts to Gas Utilities' gross margin from COVID-19 were primarily driven by reduced volumes from certain transport customers and waived customer late payment fees.

Operations and maintenance expense increased primarily due to higher property taxes due to a higher asset base driven by prior and current year capital expenditures. Lower employee costs were mostly offset by various other current year expenses. COVID-19 impacts to operations and maintenance expense included $2.5 million of additional bad debt expense which was partially offset by $2.4 million of lower travel, training, and outside services related expenses.

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

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*Operating Statistics*

| | Revenue (in thousands) | | | Gross Margin (non-GAAP) (in thousands) | | | Quantities Sold and Transported (Dth) | | |
|---|---|---|---|---|---|---|---|---|---|
| | For the year ended December 31, | | | For the year ended December 31, | | | For the year ended December 31, | | |
| | 2020 | 2019 | 2018 | 2020 | 2019 | 2018 | 2020 | 2019 | 2018 |
| Residential | $ 527,518 | $ 551,701 | $ 567,785 | $ 298,707 | $ 285,802 | $ 276,858 | 61,962,171 | 66,956,080 | 65,352,164 |
| Commercial | 193,017 | 212,229 | 214,718 | 89,590 | 88,264 | 82,529 | 28,784,319 | 32,241,441 | 30,753,361 |
| Industrial | 24,014 | 24,832 | 26,466 | 8,670 | 8,053 | 7,056 | 6,881,354 | 6,548,023 | 6,309,211 |
| Other | 582 | (1,361) | (7,899) | 582 | (1,361) | (7,899) | — | — | — |
| Total Distribution | 745,131 | 787,401 | 801,070 | 397,549 | 380,758 | 358,544 | 97,627,844 | 105,745,544 | 102,414,736 |
| Transportation and Transmission | 155,506 | 144,710 | 141,854 | 155,477 | 144,710 | 141,850 | 149,062,476 | 153,101,264 | 148,299,003 |
| Total Regulated | 900,637 | 932,111 | 942,924 | 553,026 | 525,468 | 500,394 | 246,690,320 | 258,846,808 | 250,713,739 |
| Non-regulated Services | 74,033 | 77,919 | 82,383 | 66,999 | 58,664 | 62,760 | — | — | — |
| Total Revenue, Gross Margin (non-GAAP) and Quantities Sold | $ 974,670 | $ 1,010,030 | $ 1,025,307 | $ 620,025 | $ 584,132 | $ 563,154 | 246,690,320 | 258,846,808 | 250,713,739 |

| | Revenue (in thousands) | | | Gross Margin (non-GAAP) (in thousands) | | | Quantities Sold and Transported (Dth) | | |
|---|---|---|---|---|---|---|---|---|---|
| | For the year ended December 31, | | | For the year ended December 31, | | | For the year ended December 31, | | |
| | 2020 | 2019 | 2018 | 2020 | 2019 | 2018 | 2020 | 2019 | 2018 |
| Arkansas | $ 184,849 | $ 185,201 | $ 176,660 | $ 127,720 | $ 115,899 | $ 100,917 | 28,572,621 | 30,496,243 | 30,931,390 |
| Colorado | 186,085 | 199,369 | 188,002 | 106,749 | 106,776 | 99,851 | 32,077,083 | 33,908,529 | 29,857,063 |
| Iowa | 137,982 | 151,619 | 161,843 | 69,528 | 70,290 | 68,384 | 36,824,548 | 41,795,729 | 40,668,682 |
| Kansas | 101,118 | 105,906 | 112,306 | 60,586 | 58,020 | 55,226 | 33,732,897 | 32,650,854 | 31,387,672 |
| Nebraska | 246,381 | 255,622 | 278,969 | 169,311 | 155,901 | 164,513 | 80,202,783 | 81,481,192 | 81,658,938 |
| Wyoming | 118,255 | 112,313 | 107,527 | 86,131 | 77,246 | 74,263 | 35,280,388 | 38,514,261 | 36,209,994 |
| Total Revenue, Gross Margin (non-GAAP) and Quantities Sold | $ 974,670 | $ 1,010,030 | $ 1,025,307 | $ 620,025 | $ 584,132 | $ 563,154 | 246,690,320 | 258,846,808 | 250,713,739 |

| | For the year ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2020 | | 2019 | | 2018 | |
| Heating Degree Days: | Actual | Variance From Normal | Actual | Variance From Normal | Actual | Variance From Normal |
| Arkansas [a] | 3,442 | (15)% | 3,897 | (4)% | 4,169 | 3% |
| Colorado | 6,068 | (8)% | 6,672 | 1% | 6,136 | (7)% |
| Iowa | 6,504 | (4)% | 7,200 | 6% | 7,192 | 6% |
| Kansas [a] | 4,648 | (5)% | 5,190 | 6% | 5,242 | 7% |
| Nebraska | 5,853 | (5)% | 6,578 | 7% | 6,563 | 6% |
| Wyoming | 7,289 | (4)% | 8,010 | 7% | 7,425 | (1)% |
| Combined [b] | 6,038 | (6)% | 6,840 | 5% | 6,628 | 2% |

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

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**Power Generation**

Our Power Generation segment operating results for the years ended December 31 were as follows (in thousands):

| | 2020 | Variance | 2019 | Variance | 2018 |
|---|---|---|---|---|---|
| Revenue | $ 105,047 | $ 3,789 | $ 101,258 | $ 8,807 | $ 92,451 |
| | | | | | |
| Total fuel | 8,993 | (66) | 9,059 | 467 | 8,592 |
| Operations and maintenance | 33,695 | 5,266 | 28,429 | 3,294 | 25,135 |
| Depreciation and amortization | 20,247 | 1,256 | 18,991 | 2,881 | 16,110 |
| Total operating expenses | 62,935 | 6,456 | 56,479 | 6,642 | 49,837 |
| | | | | | |
| Adjusted operating income | $ 42,112 | $ (2,667) | $ 44,779 | $ 2,165 | $ 42,614 |

2020 Compared to 2019

Revenue increased in the current year due to increased wind megawatt hours sold primarily driven by Busch Ranch II, additional Black Hills Colorado IPP fired-engine hours and higher power sales agreement prices and volumes. Operating expenses increased in the current year primarily due to a $3.1 million expense related to the early retirement of certain assets and higher depreciation and maintenance expense from new wind assets. COVID-19 impacts included $0.4 million of expenses related to the sequestration of essential employees which were mostly offset by lower travel and training expenses.

*Operating Statistics*

| | Revenue (in thousands) | | | Quantities Sold (MWh) [(a)] | | |
|---|---|---|---|---|---|---|
| For the year ended December 31, | 2020 | 2019 | 2018 | 2020 | 2019 | 2018 |
| Black Hills Colorado IPP | $ 57,057 | $ 55,191 | $ 55,331 | 1,076,819 | 935,997 | 1,000,577 |
| Black Hills Wyoming | 42,464 | 41,822 | 36,978 | 633,389 | 629,788 | 582,938 |
| Black Hills Electric Generation | 5,526 | 4,245 | 142 | 353,559 | 167,296 | 5,873 |
| Total Revenue and Quantities Sold | $ 105,047 | $ 101,258 | $ 92,451 | 2,063,767 | 1,733,081 | 1,589,388 |

(a) Company use and losses are not included in the quantities sold.

| | | For the year ended December 31, | | |
|---|---|---|---|---|
| Quantities Generated and Purchased (MWh) [(a)] | Fuel Type | 2020 | 2019 | 2018 |
| Generated: | | | | |
| Black Hills Colorado IPP | Natural Gas | 1,076,819 | 935,997 | 1,000,577 |
| Black Hills Wyoming | Coal | 551,136 | 557,119 | 501,945 |
| Black Hills Electric Generation | Wind | 353,559 | 167,296 | 5,873 |
| Total Generated | | 1,981,514 | 1,660,412 | 1,508,395 |
| Purchased: | | | | |
| Black Hills Wyoming [(b)] | Various | 82,525 | 74,199 | 83,213 |
| Total Generated and Purchased | | 82,525 | 74,199 | 83,213 |

(a) Company use and losses are not included in the quantities generated and purchased.
(b) Under the 20-year economy energy PSA (discussed in Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K) with the City of Gillette, Black Hills Wyoming purchases energy on behalf of the City of Gillette and sells that energy to the City of Gillette. MWh sold may not equal MWh generated and purchased due to a dispatch agreement Black Hills Wyoming has with South Dakota Electric to cover energy imbalances.

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| Contracted generating facilities availability by fuel type [a] | For the year ended December 31, 2020 | 2019 | 2018 |
|---|---|---|---|
| Coal | 95.4% | 94.5% | 85.8% |
| Natural gas | 99.5% | 98.6% | 99.4% |
| Wind | 92.8% | 90.6% | N/A |
| Total availability | 96.4% | 95.0% | 95.9% |
| | | | |
| Wind capacity factor | 26.6% | 23.5% | N/A |

(a) Availability and wind capacity factor are calculated using a weighted average based on capacity of our generating fleet.

**Mining**

Mining operating results for the years ended December 31 were as follows (in thousands):

| | 2020 | Variance | 2019 | Variance | 2018 |
|---|---|---|---|---|---|
| Revenue | $ 61,075 | $ (554) | $ 61,629 | $ (6,404) | $ 68,033 |
| Operations and maintenance | 39,033 | (999) | 40,032 | (3,696) | 43,728 |
| Depreciation, depletion and amortization | 9,235 | 265 | 8,970 | 1,005 | 7,965 |
| Total operating expenses | 48,268 | (734) | 49,002 | (2,691) | 51,693 |
| Adjusted operating income | $ 12,807 | $ 180 | $ 12,627 | $ (3,713) | $ 16,340 |

2020 Compared to 2019

Adjusted operating income was comparable to the prior year.

*Operating Statistics*

| For the year ended December 31, | 2020 | 2019 | 2018 |
|---|---|---|---|
| Tons of coal sold | 3,737 | 3,716 | 4,085 |
| Cubic yards of overburden moved | 8,120 | 8,534 | 8,970 |
| Coal reserves at year-end (in tons) | 181,711 | 185,448 | 189,164 |
| Revenue per ton | $ 15.67 | $ 15.94 | $ 16.11 |

**Corporate and Other**

Corporate and Other operating results for the years ended December 31 were as follows (in thousands):

| (in thousands) | 2020 | Variance | 2019 | Variance | 2018 |
|---|---|---|---|---|---|
| Adjusted operating income (loss) | $ 1,440 | $ 3,072 | $ (1,632) | $ 1,393 | $ (3,025) |

2020 Compared to 2019

The variance in Adjusted operating income (loss) was primarily due to lower unallocated employee costs.

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**Consolidated Interest Expense, Impairment of Investment, Other Income (Expense) and Income Tax Benefit (Expense)**

| (in thousands) | 2020 | Variance | 2019 | Variance | 2018 |
|---|---|---|---|---|---|
| Interest expense, net | $ (143,470) | $ (5,811) | $ (137,659) | $ 2,316 | $ (139,975) |
| Impairment of investment | (6,859) | 12,882 | (19,741) | (19,741) | — |
| Other income (expense), net | (2,293) | 3,447 | (5,740) | (4,560) | (1,180) |
| Income tax benefit (expense) | (32,918) | (3,338) | (29,580) | (53,247) | 23,667 |

2020 Compared to 2019

*Interest Expense*

The increase in Interest expense, net was driven by higher debt balances partially offset by lower interest rates.

*Impairment of Investment*

In the current year, we recorded a pre-tax non-cash write-down of $6.9 million in our investment in equity securities of a privately held oil and gas company, compared to a $20 million write-down in the prior year. The impairments in both years were triggered by continued adverse natural gas prices and liquidity concerns at the privately held oil and gas company. The remaining book value of our investment is $1.5 million, and this is our only remaining investment in oil and gas exploration and production activities. See Note 1 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional details.

*Other Income (Expense)*

The variance in Other income (expense), net was due to the prior year expensing of $5.4 million of development costs related to projects we no longer intend to construct which was partially offset by higher current year non-service defined benefit plan costs primarily driven by lower discount rates.

*Income Tax Benefit (Expense)*

For the year ended December 31, 2020, the effective tax rate was 11.9% compared to 12.2% in 2019. The lower effective tax rate is primarily due to increased tax benefits from federal production tax credits associated with new wind assets and one-time research and development tax credits partially offset by a prior year tax benefit from a federal tax loss carry-back claim including interest. See Note 17 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional details.

**Liquidity and Capital Resources**

OVERVIEW

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

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

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

In response to the February 2021 weather event and the COVID-19 pandemic, we took steps to maintain adequate liquidity to operate our businesses and fund our capital investment program as discussed in the Company Highlights above.

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The following table provides an informational summary of our financial position as of December 31 (dollars in thousands):

| Financial Position Summary | | 2020 | | 2019 |
|---|---|---|---|---|
| Cash and cash equivalents | $ | 6,356 | $ | 9,777 |
| Restricted cash and equivalents | $ | 4,383 | $ | 3,881 |
| Notes payable | $ | 234,040 | $ | 349,500 |
| Current maturities of long-term debt | $ | 8,436 | $ | 5,743 |
| Long-term debt [(a)] | $ | 3,528,100 | $ | 3,140,096 |
| Stockholders' equity | $ | 2,561,385 | $ | 2,362,123 |
| | | | | |
| Ratios | | | | |
| Long-term debt ratio | | 58 % | | 57 % |
| Total debt ratio | | 60 % | | 60 % |

(a) Carrying amount of long-term debt is net of deferred financing costs.

## CASH FLOW ACTIVITIES

The following table summarizes our cash flows for the years ended December 31 (in thousands):

| | | 2020 | | 2019 | | 2018 |
|---|---|---|---|---|---|---|
| Cash provided by (used in) | | | | | | |
| Operating activities | $ | 541,863 | $ | 505,513 | $ | 488,811 |
| Investing activities | $ | (761,664) | $ | (816,210) | $ | (465,849) |
| Financing activities | $ | 216,882 | $ | 300,210 | $ | (17,057) |

2020 Compared to 2019

**Operating Activities:**

Net cash provided by operating activities was $36 million higher than in 2019. The variance to the prior year was primarily attributable to:

- Cash earnings (income from continuing operations plus non-cash adjustments) were $20 million higher than prior year driven primarily by higher operating income at our Gas Utilities;
- Net inflows from changes in certain operating assets and liabilities were $18 million higher than prior year, primarily attributable to:
  - Cash inflows decreased by approximately $18 million primarily as a result of changes in accounts receivable and other current assets driven by warmer weather, lower commodity prices and COVID-19 related impacts;
  - Cash outflows decreased by approximately $60 million as a result of changes in accounts payable and other current liabilities driven by the impact of lower commodity prices, deferral of payroll taxes under the CARES Act and other working capital requirements; and
  - Cash outflows increased by approximately $24 million primarily as a result of changes in our regulatory assets and liabilities driven by timing of recovery and returns for fuel costs adjustments partially offset by the TCJA tax rate change that was returned to customers in the prior year.
- Cash inflows decreased $1.3 million for other operating activities.

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**Investing Activities:**

Net cash used in investing activities was $55 million lower than in 2019. This variance to the prior year was primarily attributable to:

- Capital expenditures of approximately $767 million in 2020 compared to $818 million in 2019. Higher prior year expenditures were driven by large projects such as the Natural Bridge pipeline project, the Busch Ranch II wind project and construction of the final segment of the 175-mile transmission line from Rapid City, South Dakota to Stegall, Nebraska. The current year capital expenditures included the Corriedale wind project.

- Cash inflows increased $3.6 million for other investing activities.

**Financing Activities:**

Net cash provided by financing activities was $83 million lower than in 2019. This variance to the prior year was primarily attributable to:

- Cash inflows decreased $82 million due to maturities and repayments of long and short-term debt in excess of issuances;

- Cash outflows increased $11 million due to increased dividends paid on common stock; and

- Cash outflows decreased by $9.7 million for other financing activities primarily driven by lower current year financing costs incurred in the June 17, 2020 debt transaction compared to prior year financing costs incurred in the June 17, 2019 and October 3, 2019 debt transactions.

## CAPITAL SOURCES

### Revolving Credit Facility and CP Program

We have a $750 million Revolving Credit Facility that matures on July 30, 2023 with two one-year extension options (subject to consent from lenders). This facility includes an accordion feature that allows us, with the consent of the administrative agent, the issuing agents and each bank increasing or providing a new commitment, to increase total commitments up to $1.0 billion. We also have a $750 million, unsecured CP Program that is backstopped by the Revolving Credit Facility. Amounts outstanding under the Revolving Credit Facility and the CP Program, either individually or in the aggregate, cannot exceed $750 million.

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

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

Our Revolving Credit Facility and CP Program had the following borrowings, outstanding letters of credit, and available capacity (in millions):

| Credit Facility | Expiration | Current Capacity | Short-term borrowings at December 31, 2020 | Letters of Credit [(a)] at December 31, 2020 | Available Capacity at December 31, 2020 |
|---|---|---|---|---|---|
| Revolving Credit Facility and CP Program | July 30, 2023 | $ 750 | $ 234 | $ 25 | $ 491 |

__________
(a) Letters of credit are off-balance sheet commitments that reduce the borrowing capacity available on our corporate Revolving Credit. For more information on these letters of credit, see Note 9 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

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The weighted average interest rate on short-term borrowings at December 31, 2020 was 0.27%. Short-term borrowing activity for the year ended December 31, 2020 was:

| | | (dollars in millions) |
|---|---|---|
| Maximum amount outstanding (based on daily outstanding balances) | $ | 366 |
| Average amount outstanding (based on daily outstanding balances) | $ | 193 |
| Weighted average interest rate | | 0.90 % |

See Note 9 of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for more information on our Revolving Credit Facility and CP Program.

**Utility Money Pool**

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

**Long-term Debt**

Our Long-term debt and associated interest payments due by year are shown below (in thousands). For more information on our long-term debt, see Note 9 of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

| | Payments Due by Period | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2021 | 2022 | 2023 | 2024 | 2025 | Thereafter | Total |
| Principal payments on Long-term debt including current maturities [(a)] | $ 8,436 | $ — | $ 525,000 | $ — | $ — | $ 3,035,000 | $ 3,568,436 |
| Interest payments on Long-term debt [(a)] | 141,561 | 141,547 | 141,547 | 119,235 | 119,235 | 1,209,188 | 1,872,313 |

(a) Long-term debt amounts do not include deferred financing costs or discounts or premiums on debt. Estimated interest payments on variable rate debt are calculated by utilizing the applicable rates as of December 31, 2020.

**Covenant Requirements**

The Revolving Credit Facility and Wyoming Electric's financing agreements contain covenant requirements. We were in compliance with these covenants as of December 31, 2020. See additional information in Note 9 of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K

**Equity**

*Shelf Registration*

We have a shelf registration statement on file with the SEC under which we may issue, from time to time, senior debt securities, subordinated debt securities, common stock, preferred stock, warrants and other securities. Although the shelf registration statement does not limit our issuance capacity, our ability to issue securities is limited to the authority granted by our Board of Directors, certain covenants in our financing arrangements and restrictions imposed by federal and state regulatory authorities. The shelf registration expires in August 2023. Our articles of incorporation authorize the issuance of 100 million shares of common stock and 25 million shares of preferred stock. As of December 31, 2020, we had approximately 63 million shares of common stock outstanding and no shares of preferred stock outstanding.

*ATM*

Our ATM allows us to sell shares of our common stock with an aggregate value of up to $400 million. The shares may be offered from time to time pursuant to a sales agreement dated August 4, 2020. Shares of common stock are offered pursuant to our shelf registration statement filed with the SEC. In 2020, we did not issue any shares of common stock under the ATM.

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

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**Future Financing Plans**

We will continue to assess debt and equity needs to support our capital investment plans and other key strategic objectives. In 2021, we expect to fund our capital plan and strategic objectives by using cash generated from operating activities, our Revolving Credit Facility and CP Program, and issuing $100 million to $120 million of common stock under the ATM. As discussed in the Company Highlights above, on February 24, 2021, we entered into an $800 million term loan maturing on November 23, 2021. We expect to repay a portion of this term loan prior to maturity and refinance the remaining portion in longer-term debt.

**CREDIT RATINGS**

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

The following table represents the credit ratings, outlook and risk profile of BHC at December 31, 2020:

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

(a) On April 10, 2020, S&P reported BBB+ rating and maintained a Stable outlook.
(b) On December 21, 2020, Moody's reported Baa2 rating and maintained a Stable outlook.
(c) On August 20, 2020, Fitch reported BBB+ rating and maintained a Stable outlook.

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

The following table represents the credit ratings of South Dakota Electric at December 31, 2020:

| Rating Agency | Senior Secured Rating |
|---|---|
| S&P [(a)] | A |
| Moody's [(b)] | A1 |
| Fitch [(c)] | A |

(a) On April 16, 2020, S&P reported A rating.
(b) On December 21, 2020, Moody's reported A1 rating.
(c) On August 20, 2020, Fitch reported A rating.

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

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## CAPITAL REQUIREMENTS

### Capital Expenditures

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

As discussed in the Company Highlights above, there have been limited impacts from COVID-19 on our capital investment plan and we do not anticipate a significant impact in 2021.

Our capital expenditures for the three years ended December 31 were as follows (in thousands):

| | 2020 | 2019 | 2018 |
|---|---|---|---|
| Capital Expenditures By Segment [(a)]: | | | |
| Electric Utilities | $ 271,104 | $ 222,911 | $ 152,524 |
| Gas Utilities | 449,209 | 512,366 | 288,438 |
| Power Generation | 9,329 | 85,346 | 30,945 |
| Mining | 8,250 | 8,430 | 18,794 |
| Corporate and Other | 17,500 | 20,702 | 11,723 |
| Capital expenditures before discontinued operations | 755,392 | 849,755 | 502,424 |
| Discontinued operations | — | — | 2,402 |
| Total capital expenditures | $ 755,392 | $ 849,755 | $ 504,826 |

(a) Includes accruals for property, plant and equipment as disclosed as supplemental cash flow information in the Consolidated Statements of Cash Flows in the Consolidated Financial Statements in this Annual Report on Form 10-K.

### Unconditional Purchase Obligations

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

### Defined Benefit Pension Plan

We have one defined benefit pension plan, the Black Hills Retirement Plan (Pension Plan). The unfunded status of the Pension Plan is defined as the amount the projected benefit obligation exceeds the plan assets. The unfunded status of the plan is $40 million as of December 31, 2020 compared to $51 million as of December 31, 2019. We do not have required 2021 contributions and currently do not expect to contribute to our Pension Plan. See further information in Note 15 of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-Ks.

### Common Stock Dividends

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

Additionally, there are certain statutory limitations that could affect future cash dividends paid. Federal law places limits on the ability of public utilities within a holding company structure to declare dividends. Specifically, under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. The utility subsidiaries' dividends may be limited directly or indirectly by state regulatory commissions or bond indenture covenants. See additional information in Note 9 of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

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On January 27, 2021, our Board of Directors declared a quarterly dividend of $0.565 per share, equivalent to an annual dividend rate of $2.26 per share. The table below provides our dividends paid (in thousands), dividend payout ratio and dividends paid per share for the three years ended December 31:

| | 2020 | 2019 | 2018 |
|---|---|---|---|
| Common Stock Dividends Paid | $ 135,439 | $ 124,647 | $ 106,591 |
| Dividend Payout Ratio | 60 % | 63% | 40% |
| Dividends Per Share | $ 2.17 | $ 2.05 | $ 1.93 |

Our three-year compound annualized dividend growth rate was 6.2% and all dividends were paid out of available operating cash flows.

**Collateral Requirements**

Our Utilities maintain wholesale commodity contracts for the purchases and sales of electricity and natural gas which have performance assurance provisions that allow the counterparty to require collateral postings under certain conditions, including when requested on a reasonable basis due to a deterioration in our financial condition or nonperformance. A significant downgrade in our credit ratings, such as a downgrade to a level below investment grade, could result in counterparties requiring collateral postings under such adequate assurance provisions. The amount of credit support that we may be required to provide at any point in the future is dependent on the amount of the initial transaction, changes in the market price, open positions and the amounts owed by or to the counterparty. At December 31, 2020, we had sufficient liquidity to cover collateral that could be required to be posted under these contracts. The cash collateral we were required to post at December 31, 2020 was not material. For the year ended December 31, 2020, we did not experience any requests to post additional collateral, including for concerns over a potential deterioration of our financial condition due to COVID-19.

**Guarantees**

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

## Critical Accounting Policies Involving Significant Estimates

We prepare our consolidated financial statements in conformity with GAAP. In many cases, the accounting treatment of a particular transaction is specifically dictated by GAAP and does not require management's judgment in application. There are also areas which require management's judgment in selecting among available GAAP alternatives. We are required to make certain estimates, judgments and assumptions that we believe are reasonable based upon the information available. We continue to closely monitor the rapidly evolving and uncertain impact of COVID-19 on our critical accounting estimates including, but not limited to, collectibility of customer receivables, recoverability of regulatory assets, impairment risk of goodwill and long-lived assets, valuation of pension assets and liabilities and contingent liabilities. These estimates and assumptions affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods presented. Actual results may differ from our estimates and to the extent there are material differences between these estimates, judgments or assumptions and actual results, our financial statements will be affected. We believe the following accounting estimates are the most critical in understanding and evaluating our reported financial results. We have reviewed these critical accounting estimates and related disclosures with our Audit Committee.

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

**Regulation**

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

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

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

As of December 31, 2020 and 2019, we had total regulatory assets of $278 million and $271 million, respectively, and total regulatory liabilities of $533 million and $537 million, respectively. See Note 2 of the Notes to Consolidated Financial Statements for further information.

**Goodwill**

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

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

Application of the goodwill impairment test requires judgment, including the identification of reporting units and determining the fair value of the reporting unit. We have determined that the reporting units for goodwill impairment testing are our operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which the Chief Operating Decision Maker (CODM) regularly reviews the operating results. We estimate the fair value of our reporting units using a combination of an income approach, which estimates fair value based on discounted future cash flows, and a market approach, which estimates fair value based on market comparables within the utility and energy industries. These valuations require significant judgments, including, but not limited to: 1) estimates of future cash flows, based on our internal five-year business plans and adjusted as appropriate for our view of market participant assumptions, with long range cash flows estimated using a terminal value calculation; 2) estimates of long-term growth rates for our businesses; 3) the determination of an appropriate weighted-average cost of capital or discount rate; and 4) the utilization of market information such as recent sales transactions for comparable assets within the utility and energy industries. Varying by reporting unit, weighted average cost of capital in the range of 5% to 6% and long-term growth rate projections in the 1% to 2% range were utilized in the goodwill impairment test performed as of October 1, 2020. Although 1% to 2% was used for a long-term growth rate projection, the short-term projected growth rate is higher with planned recovery of capital investments through rider mechanisms and rate reviews. Under the market approach, we estimate fair value using multiples derived from comparable sales transactions and enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, we add a reasonable control premium when calculating fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants.

The estimates and assumptions used in the impairment assessments are based on available market information and we believe they are reasonable. However, variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated. For the years ended December 31, 2020, 2019, and 2018, there were no impairment losses recorded. At December 31, 2020, the fair value substantially exceeded the carrying value at all reporting units.

As described in Note 1 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K, we adopted ASU 2017-04, Simplifying the Test for Goodwill Impairment, prospectively on January 1, 2020.

**Pension and Other Postretirement Benefits**

As described in Note 15 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K, we have one defined benefit pension plan, one defined post-retirement healthcare plan and several non-qualified retirement plans. A Master Trust holds the assets for the pension plan. A VEBA trust for the funded portion of the post-retirement healthcare plan has also been established.

Accounting for pension and other postretirement benefit obligations involves numerous assumptions, the most significant of which relate to the discount rates, healthcare cost trend rates, expected return on plan assets, compensation increases, retirement rates and mortality rates. The determination of our obligation and expenses for pension and other postretirement benefits is dependent on the assumptions determined by management and used by actuaries in calculating the amounts. Although we believe our assumptions are appropriate, significant differences in our actual experience or significant changes in our assumptions may materially affect our pension and other postretirement obligations and our future expense.

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Effective January 1, 2020, the Company changed its method of accounting for net periodic benefit cost. Prior to the change, the Company used a calculated value for determining market-related value of plan assets which amortized the effects of gains and losses over a five-year period. Effective with the accounting change, the Company uses a calculated value for the return-seeking assets (equities) in the portfolio and fair value for the liability-hedging assets (fixed income). The Company considers the fair value method for determining market-related value of liability-hedging assets to be a preferable method of accounting because asset-related gains and losses are subject to amortization into pension cost immediately. Additionally, the fair value for liability-hedging assets allows for the impact of gains and losses on this portion of the asset portfolio to be reflected in tandem with changes in the liability which is linked to changes in the discount rate assumption for re-measurement.

The 2021 pension benefit cost for our non-contributory funded pension plan is expected to be $0.5 million compared to $4 million in 2020. The decrease in the expected 2021 pension benefit cost is driven primarily by favorable asset returns partially offset by a decrease in the discount rate.

The effect of hypothetical changes to selected assumptions on the pension and other postretirement benefit plans would be as follows in thousands of dollars:

| | | December 31, | |
|---|---|---|---|
| Assumptions | Percentage Change | 2020 Increase/(Decrease) PBO/APBO [(a)] | 2021 Increase/(Decrease) Expense - Pretax |
| Pension | | | |
| Discount rate [(b)] | +/- 0.5 | (30,334)/33,326 | (3,162)/3,743 |
| Expected return on assets | +/- 0.5 | N/A | (2,367)/2,372 |
| | | | |
| OPEB | | | |
| Discount rate [(b)] | +/- 0.5 | (3,139)/3,425 | (100)/108 |
| Expected return on assets | +/- 0.5 | N/A | (38)/38 |

(a) Projected benefit obligation (PBO) for the pension plan and accumulated postretirement benefit obligation (APBO) for OPEB plans.
(b) Impact on service cost, interest cost and amortization of gains or losses.

**Income Taxes**

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

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

As of December 31, 2020, we have a regulatory liability associated with TCJA related items of $285 million, completing our accounting for the revaluation of deferred taxes pursuant to the TCJA. A significant portion of the excess deferred taxes are subject to the average rate assumption method, as prescribed by the IRS, and will generally be amortized as a reduction of customer rates over the remaining lives of the related assets.

As of December 31, 2020, the Company has amortized $13.3 million of regulatory liability associated with TCJA related items. The portion that was eligible for amortization under the average rate assumption method in 2020, but is awaiting resolution of the treatment of these amounts in future regulatory proceedings, has not been recognized and may be refunded in customer rates at any time in accordance with the resolution of pending or future regulatory proceedings.
In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. If we determine that we will be unable to realize all or part of our deferred tax assets in the future, an adjustment to the deferred tax asset would be charged to income in the period such determination was made. Although we believe our assumptions, judgments and estimates are reasonable, changes in tax laws or our interpretations of tax laws and the resolution of current and any future tax audits could significantly impact the amounts provided for income taxes in our consolidated financial statements.

See Note 17 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

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**New Accounting Pronouncements**

See Note 1 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for information on new accounting standards adopted in 2020 or pending adoption.

**ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

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

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

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

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

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

**Commodity Price Risk**

*Electric and Gas Utilities*

Our utilities have various provisions that allow them to pass the prudently-incurred cost of energy through to the customer. To the extent energy prices are higher or lower than amounts in our current billing rates, adjustments are made on a periodic basis to reflect billed amounts to match the actual energy cost we incurred. In Colorado, South Dakota and Wyoming, we have ECA or PCA provisions that adjust electric rates when energy costs are higher or lower than the costs included in our tariffs. In Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming, we have GCA provisions that adjust natural gas rates when our natural gas costs are higher or lower than the energy cost included in our tariffs. These adjustments are subject to periodic prudence reviews by the state regulatory commissions.

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

For our regulated Utilities' hedging plans, unrealized and realized gains and losses, as well as option premiums and commissions on these transactions are recorded as Regulatory assets or Regulatory liabilities in the accompanying Consolidated Balance Sheets in accordance with the state utility commission guidelines. When the related costs are recovered through our rates, the hedging activity is recognized in the Consolidated Statements of Income. See additional information in Note 11 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

*Wholesale Power*

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

A potential risk related to wholesale power sales is the price risk arising from the sale of power that exceeds our generating capacity. These potential short positions can arise from unplanned plant outages or from unanticipated load demands. To manage such risk, we restrict wholesale off-system sales to amounts by which our anticipated generating capabilities and purchased power resources exceed our anticipated load requirements plus a required reserve margin.

*Black Hills Energy Services*

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

See additional commodity risk and derivative information in Note 11 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

**Interest Rate Risk**

Periodically, we have engaged in activities to manage risks associated with changes in interest rates. We have utilized pay-fixed interest rate swap agreements to reduce exposure to interest rate fluctuations associated with floating rate debt obligations and anticipated debt refinancings. At December 31, 2020, we had no interest rate swaps in place. Further details of past swap agreements are set forth in Note 11 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

At December 31, 2020, 93% of our debt is fixed rate debt, which limits our exposure to variable interest rate fluctuations. A hypothetical 100 basis point increase in the benchmark rate on our variable rate debt would have increased annual pretax interest expense by approximately $2.1 million and $4.6 million for the years ended December 31, 2020 and 2019, respectively. See Note 9 for further information on cash amounts outstanding under short- and long-term variable rate borrowings.

We are subject to interest rate risk associated with our pension and post-retirement benefit obligations. Changes in interest rates impact the liabilities associated with these benefit plans as well as the amount of income or expense recognized for these plans. Declines in the value of the plan assets could diminish the funded status of the pension plans and potentially increase the requirements to make cash contributions to these plans. See additional information in Critical Accounting Estimates in Item 7 and Note 15 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

**Credit Risk**

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

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer's current creditworthiness, as determined by review of their current credit information. We maintain a provision for estimated credit losses based upon historical experience, changes in current market conditions, expected losses and any specific customer collection issue that is identified. Our credit exposure at December 31, 2020 was concentrated primarily among retail utility customers, investment grade companies, cooperative utilities and federal agencies.

See more information in Notes 1 and 11 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

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## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

### Management's Report on Internal Control over Financial Reporting

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

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

Under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2020, based on the criteria set forth in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission "COSO". This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Based on our evaluation, we have concluded that our internal control over financial reporting was effective as of December 31, 2020.

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of Black Hills Corporation's financial statements, has issued an attestation report on the effectiveness of Black Hills Corporation's internal control over financial reporting as of December 31, 2020. Deloitte & Touche LLP's report on Black Hills Corporation's internal control over financial reporting is included herein.

Black Hills Corporation

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## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

### Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Black Hills Corporation and subsidiaries (the "Company") as of December 31, 2020 and 2019, the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows, for each of the three years in the period ended December 31, 2020, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2021, expressed an unqualified opinion on the Company's internal control over financial reporting.

### Basis for Opinion

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

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

### Critical Audit Matter

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

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

*Critical Audit Matter Description*

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

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

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

*How the Critical Audit Matter Was Addressed in the Audit*

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

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

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 26, 2021

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

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## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

### Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Black Hills Corporation and subsidiaries (the "Company") as of December 31, 2020, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2020, of the Company and our report dated February 26, 2021, expressed an unqualified opinion on those financial statements.

### Basis for Opinion

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

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

### Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 26, 2021

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**BLACK HILLS CORPORATION**
**CONSOLIDATED STATEMENTS OF INCOME**

| Year ended | December 31, 2020 | December 31, 2019 | December 31, 2018 |
|---|---|---|---|
| | (in thousands, except per share amounts) | | |
| Revenue | $ 1,696,941 | $ 1,734,900 | $ 1,754,268 |
| Operating expenses: | | | |
| Fuel, purchased power and cost of natural gas sold | 492,404 | 570,829 | 625,610 |
| Operations and maintenance | 495,404 | 495,994 | 481,706 |
| Depreciation, depletion and amortization | 224,457 | 209,120 | 196,328 |
| Taxes - property and production | 56,373 | 52,915 | 51,746 |
| Other operating expenses | — | — | 1,841 |
| Total operating expenses | 1,268,638 | 1,328,858 | 1,357,231 |
| Operating income | 428,303 | 406,042 | 397,037 |
| Other income (expense): | | | |
| Interest expense incurred net of amounts capitalized (including amortization of debt issuance costs, premiums and discounts) | (144,931) | (139,291) | (141,616) |
| Interest income | 1,461 | 1,632 | 1,641 |
| Impairment of investment | (6,859) | (19,741) | — |
| Other income (expense), net | (2,293) | (5,740) | (1,180) |
| Total other income (expense) | (152,622) | (163,140) | (141,155) |
| Income before income taxes | 275,681 | 242,902 | 255,882 |
| Income tax benefit (expense) | (32,918) | (29,580) | 23,667 |
| Income from continuing operations | 242,763 | 213,322 | 279,549 |
| Net (loss) from discontinued operations | — | — | (6,887) |
| Net income | 242,763 | 213,322 | 272,662 |
| Net income attributable to noncontrolling interest | (15,155) | (14,012) | (14,220) |
| Net income available for common stock | $ 227,608 | $ 199,310 | $ 258,442 |
| Amounts attributable to common shareholders: | | | |
| Net income from continuing operations | $ 227,608 | $ 199,310 | $ 265,329 |
| Net (loss) from discontinued operations | — | — | (6,887) |
| Net income available for common stock | $ 227,608 | $ 199,310 | $ 258,442 |
| Earnings (loss) per share of common stock, Basic - | | | |
| Earnings from continuing operations | $ 3.65 | $ 3.29 | $ 4.88 |
| (Loss) from discontinued operations | — | — | (0.13) |
| Total earnings per share of common stock, Basic | $ 3.65 | $ 3.29 | $ 4.75 |
| Earnings (loss) per share of common stock, Diluted - | | | |
| Earnings from continuing operations | $ 3.65 | $ 3.28 | $ 4.78 |
| (Loss) from discontinued operations | — | — | (0.12) |
| Total earnings per share of common stock, Diluted | $ 3.65 | $ 3.28 | $ 4.66 |
| Weighted average common shares outstanding: | | | |
| Basic | 62,378 | 60,662 | 54,420 |
| Diluted | 62,439 | 60,798 | 55,486 |

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

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**BLACK HILLS CORPORATION**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**

| Year ended | December 31, 2020 | December 31, 2019 | December 31, 2018 |
|---|---|---|---|
| | | (in thousands) | |
| Net income | $ 242,763 | $ 213,322 | $ 272,662 |
| | | | |
| Other comprehensive income (loss), net of tax: | | | |
| Benefit plan liability adjustments - net gain (loss) (net of tax of $191, $1,886 and $(660), respectively) | (1,062) | (6,253) | 2,155 |
| Benefit plan liability adjustments - prior service costs (net of tax of $0, $2 and $0 respectively) | — | (8) | — |
| Reclassification adjustment of benefit plan liability - net loss (net of tax of $(958), $434 and $(586), respectively) | 1,429 | 1,179 | 1,901 |
| Reclassification adjustment of benefit plan liability - prior service cost (net of tax of $23, $19 and $43, respectively) | (80) | (58) | (135) |
| Derivative instruments designated as cash flow hedges: | | | |
| Reclassification of net realized (gains) losses on settled/amortized interest rate swaps (net of tax of $(287), $(666) and $(599), respectively) | 2,564 | 2,185 | 2,252 |
| Net unrealized gains (losses) on commodity derivatives (net of tax of $14, $126 and $(228), respectively) | (47) | (422) | 755 |
| Reclassification of net realized (gains) losses on settled commodity derivatives (net of tax of $(96), $55 and $(31), respectively) | 505 | (362) | 99 |
| Other comprehensive income (loss), net of tax | 3,309 | (3,739) | 7,027 |
| | | | |
| Comprehensive income | 246,072 | 209,583 | 279,689 |
| Less: comprehensive income attributable to non-controlling interest | (15,155) | (14,012) | (14,220) |
| Comprehensive income available for common stock | $ 230,917 | $ 195,571 | $ 265,469 |

See Note 13 for additional disclosures related to Comprehensive Income.

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

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**BLACK HILLS CORPORATION**
**CONSOLIDATED BALANCE SHEETS**

| | As of December 31, 2020 | As of December 31, 2019 |
|---|---|---|
| | (in thousands) | |
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 6,356 | $ 9,777 |
| Restricted cash and equivalents | 4,383 | 3,881 |
| Accounts receivable, net | 265,961 | 255,805 |
| Materials, supplies and fuel | 117,400 | 117,172 |
| Derivative assets, current | 1,848 | 342 |
| Income tax receivable, net | 19,446 | 16,446 |
| Regulatory assets, current | 51,676 | 43,282 |
| Other current assets | 26,221 | 26,479 |
| Total current assets | 493,291 | 473,184 |
| | | |
| Property, plant and equipment | 7,305,530 | 6,784,679 |
| Less accumulated depreciation and depletion | (1,285,816) | (1,281,493) |
| Total property, plant and equipment, net | 6,019,714 | 5,503,186 |
| | | |
| Other assets: | | |
| Goodwill | 1,299,454 | 1,299,454 |
| Intangible assets, net | 11,944 | 13,266 |
| Regulatory assets, non-current | 226,582 | 228,062 |
| Other assets, non-current | 37,801 | 41,305 |
| Total other assets, non-current | 1,575,781 | 1,582,087 |
| TOTAL ASSETS | $ 8,088,786 | $ 7,558,457 |

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

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**BLACK HILLS CORPORATION**
**CONSOLIDATED BALANCE SHEETS**
**(Continued)**

| | As of December 31, 2020 | As of December 31, 2019 |
|---|---|---|
| | (in thousands, except share amounts) | |
| **LIABILITIES AND EQUITY** | | |
| Current liabilities: | | |
| Accounts payable | $ 183,340 | $ 193,523 |
| Accrued liabilities | 243,612 | 226,767 |
| Derivative liabilities, current | 2,044 | 2,254 |
| Regulatory liabilities, current | 25,061 | 33,507 |
| Notes payable | 234,040 | 349,500 |
| Current maturities of long-term debt | 8,436 | 5,743 |
| Total current liabilities | 696,533 | 811,294 |
| | | |
| Long-term debt, net of current maturities | 3,528,100 | 3,140,096 |
| | | |
| Deferred credits and other liabilities: | | |
| Deferred income tax liabilities, net | 408,624 | 360,719 |
| Regulatory liabilities, non-current | 507,659 | 503,145 |
| Benefit plan liabilities | 150,556 | 154,472 |
| Other deferred credits and other liabilities | 134,667 | 124,662 |
| Total deferred credits and other liabilities | 1,201,506 | 1,142,998 |
| | | |
| Commitments, contingencies and guarantees (Note 3) | | |
| | | |
| Equity: | | |
| Stockholders' equity - | | |
| Common stock $1.00 par value; 100,000,000 shares authorized; issued: 62,827,179 and 61,480,658, respectively | 62,827 | 61,481 |
| Additional paid-in capital | 1,657,285 | 1,552,788 |
| Retained earnings | 870,738 | 778,776 |
| Treasury stock at cost - 32,492 and 3,956, respectively | (2,119) | (267) |
| Accumulated other comprehensive income (loss) | (27,346) | (30,655) |
| Total stockholders' equity | 2,561,385 | 2,362,123 |
| Noncontrolling interest | 101,262 | 101,946 |
| Total equity | 2,662,647 | 2,464,069 |
| | | |
| TOTAL LIABILITIES AND TOTAL EQUITY | $ 8,088,786 | $ 7,558,457 |

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

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## BLACK HILLS CORPORATION
## CONSOLIDATED STATEMENTS OF CASH FLOWS

| Year ended | December 31, 2020 | December 31, 2019 | December 31, 2018 |
|---|---|---|---|
| | | (in thousands) | |
| Operating activities: | | | |
| Net income | $ 242,763 | $ 213,322 | $ 272,662 |
| Loss from discontinued operations, net of tax | — | — | 6,887 |
| Income from continuing operations | 242,763 | 213,322 | 279,549 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, depletion and amortization | 224,457 | 209,120 | 196,328 |
| Deferred financing cost amortization | 7,883 | 7,838 | 7,845 |
| Impairment of investment | 6,859 | 19,741 | — |
| Stock compensation | 5,373 | 12,095 | 12,390 |
| Deferred income taxes | 38,091 | 38,020 | (24,239) |
| Employee benefit plans | 11,997 | 12,406 | 14,068 |
| Other adjustments, net | 11,669 | 16,485 | 5,836 |
| Change in certain operating assets and liabilities: | | | |
| Materials, supplies and fuel | 2,755 | 2,052 | (2,919) |
| Accounts receivable and other current assets | (10,843) | 7,578 | (45,966) |
| Accounts payable and other current liabilities | 24,659 | (34,906) | 5,305 |
| Regulatory assets - current | (5,047) | 23,619 | 33,608 |
| Regulatory liabilities - current | (10,706) | (15,158) | 18,533 |
| Contributions to defined benefit pension plans | (12,700) | (12,700) | (12,700) |
| Other operating activities, net | 4,653 | 6,001 | 6,689 |
| Net cash provided by operating activities of continuing operations | 541,863 | 505,513 | 494,327 |
| Net cash provided by (used in) operating activities of discontinued operations | — | — | (5,516) |
| Net cash provided by operating activities | 541,863 | 505,513 | 488,811 |
| | | | |
| Investing activities: | | | |
| Property, plant and equipment additions | (767,404) | (818,376) | (457,524) |
| Purchase of investment | — | — | (24,429) |
| Other investing activities | 5,740 | 2,166 | (4,281) |
| Net cash (used in) investing activities of continuing operations | (761,664) | (816,210) | (486,234) |
| Net cash provided by investing activities of discontinued operations | — | — | 20,385 |
| Net cash (used in) investing activities | (761,664) | (816,210) | (465,849) |
| | | | |
| Financing activities: | | | |
| Dividends paid on common stock | (135,439) | (124,647) | (106,591) |
| Common stock issued | 99,278 | 101,358 | 300,834 |
| Net (payments) borrowings of short-term debt | (115,460) | 163,880 | (25,680) |
| Long-term debt - issuance | 400,000 | 1,100,000 | 700,000 |
| Long-term debt - repayments | (8,597) | (905,743) | (854,743) |
| Distributions to noncontrolling interests | (15,839) | (17,901) | (19,617) |
| Other financing activities | (7,061) | (16,737) | (11,260) |
| Net cash provided by (used in) financing activities | 216,882 | 300,210 | (17,057) |
| | | | |
| Net change in cash, restricted cash and cash equivalents | (2,919) | (10,487) | 5,905 |
| | | | |
| Cash, restricted cash and cash equivalents beginning of year | 13,658 | 24,145 | 18,240 |
| Cash, restricted cash and cash equivalents end of year | $ 10,739 | $ 13,658 | $ 24,145 |
| | | | |
| Supplemental cash flow information: | | | |
| Cash (paid) refunded during the period for continuing operations: | | | |
| Interest (net of amounts capitalized) | $ (136,549) | $ (131,774) | $ (137,965) |
| Income taxes | $ 2,172 | $ 4,682 | $ (14,730) |
| | | | |
| Non-cash investing and financing activities from continuing operations: | | | |
| Accrued property, plant and equipment purchases at December 31 | $ 72,215 | $ 91,491 | $ 69,017 |
| Increase in capitalized assets associated with asset retirement obligations | $ 4,774 | $ 5,044 | $ 2,625 |

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

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**BLACK HILLS CORPORATION**
**CONSOLIDATED STATEMENTS OF EQUITY**

| (in thousands except share amounts) | Common Stock Shares | Common Stock Value | Treasury Stock Shares | Treasury Stock Value | Additional Paid in Capital | Retained Earnings | AOCI | Non controlling Interest | Total |
|---|---|---|---|---|---|---|---|---|---|
| **Balance at December 31, 2017** | 53,579,986 | $ 53,580 | 39,064 | $ (2,306) | $ 1,150,285 | $ 548,617 | $ (41,202) | $ 111,232 | $ 1,820,206 |
| Net income available for common stock | — | — | — | — | — | 258,442 | — | 14,220 | 272,662 |
| Other comprehensive income (loss), net of tax | — | — | — | — | — | — | 7,027 | — | 7,027 |
| Reclassification of certain tax effects from AOCI | — | — | — | — | — | — | 740 | — | 740 |
| Reclassification to regulatory asset | — | — | — | — | — | — | 6,519 | — | 6,519 |
| Dividends on common stock ($1.93 per share) | — | — | — | — | — | (106,591) | — | — | (106,591) |
| Share-based compensation | 92,830 | 93 | 5,189 | (204) | 7,301 | — | — | — | 7,190 |
| Issuance of common stock | 6,371,690 | 6,372 | — | — | 292,628 | — | — | — | 299,000 |
| Issuance costs | — | — | — | — | (15) | — | — | — | (15) |
| Dividend reinvestment and stock purchase plan | 4,061 | 4 | — | — | 216 | — | — | — | 220 |
| Other stock transactions | — | — | — | — | 154 | (72) | — | — | 82 |
| Distributions to noncontrolling interest | — | — | — | — | — | — | — | (19,617) | (19,617) |
| **Balance at December 31, 2018** | 60,048,567 | $ 60,049 | 44,253 | $ (2,510) | $ 1,450,569 | $ 700,396 | $ (26,916) | $ 105,835 | $ 2,287,423 |
| Net income available for common stock | — | — | — | — | — | 199,310 | — | 14,012 | 213,322 |
| Other comprehensive income (loss), net of tax | — | — | — | — | — | — | (3,739) | — | (3,739) |
| Dividends on common stock ($2.05 per share) | — | — | — | — | — | (124,647) | — | — | (124,647) |
| Share-based compensation | 103,759 | 104 | (40,297) | 2,243 | 4,729 | — | — | — | 7,076 |
| Issuance of common stock | 1,328,332 | 1,328 | — | — | 98,672 | — | — | — | 100,000 |
| Issuance costs | — | — | — | — | (1,182) | — | — | — | (1,182) |
| Other | — | — | — | — | — | 327 | — | — | 327 |
| Implementation of ASU 2016-02 Leases | — | — | — | — | — | 3,390 | — | — | 3,390 |
| Distributions to noncontrolling interest | — | — | — | — | — | — | — | (17,901) | (17,901) |
| **Balance at December 31, 2019** | 61,480,658 | $ 61,481 | 3,956 | $ (267) | $ 1,552,788 | $ 778,776 | $ (30,655) | $ 101,946 | $ 2,464,069 |
| Net income available for common stock | — | — | — | — | — | 227,608 | — | 15,155 | 242,763 |
| Other comprehensive income (loss), net of tax | — | — | — | — | — | — | 3,309 | — | 3,309 |
| Dividends on common stock ($2.17 per share) | — | — | — | — | — | (135,439) | — | — | (135,439) |
| Share-based compensation | 123,578 | 123 | 28,536 | (1,852) | 6,923 | — | — | — | 5,194 |
| Issuance of common stock | 1,222,943 | 1,223 | — | — | 98,777 | — | — | — | 100,000 |
| Issuance costs | — | — | — | — | (1,203) | — | — | — | (1,203) |
| Implementation of ASU 2016-13 Financial Instruments - - Credit Losses | — | — | — | — | — | (207) | — | — | (207) |
| Distributions to noncontrolling interest | — | — | — | — | — | — | — | (15,839) | (15,839) |
| **Balance at December 31, 2020** | 62,827,179 | $ 62,827 | 32,492 | $ (2,119) | $ 1,657,285 | $ 870,738 | $ (27,346) | $ 101,262 | $ 2,662,647 |

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

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**BLACK HILLS CORPORATION**
**Notes to Consolidated Financial Statements**
**December 31, 2020, 2019 and 2018**

## (1) BUSINESS DESCRIPTION AND SIGNIFICANT ACCOUNTING POLICIES

### Business Description

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

### Segment Reporting

Our reportable segments are based on our method of internal reporting, which is generally segregated by differences in products, services and regulation. 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. Our Gas Utilities segment consists of the operating results of our regulated natural gas utility subsidiaries in Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming.

Both of our non-utility business segments support our Electric Utilities. Our Power Generation segment, which is conducted through Black Hills Electric Generation and its subsidiaries, engages in independent power generation activities in Colorado, Iowa and Wyoming. Our Mining segment, which is conducted through WRDC, engages in coal mining activities located near Gillette, Wyoming. For further descriptions of our reportable business segments, see Note 18.

On November 1, 2017, our Board of Directors approved a complete divestiture of our Oil and Gas segment. We completed the divestiture of our Oil and Gas segment in 2018. The Oil and Gas segment results of operations were shown in income (loss) from discontinued operations, other than certain general and administrative costs and interest expense which did not meet the criteria for income (loss) from discontinued operations. Unless otherwise noted, the amounts presented in the accompanying Notes to Consolidated Financial Statements relate to the Company's continuing operations.

### Use of Estimates and Basis of Presentation

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

### COVID-19 Pandemic

In March 2020, the World Health Organization categorized COVID-19 as a pandemic and the President of the United States declared the outbreak a national emergency. The U.S. government has deemed electric and natural gas utilities to be critical infrastructure sectors that provide essential services during this emergency. As a provider of essential services, the Company has an obligation to provide services to our customers. The Company remains focused on protecting the health of our customers, employees and the communities in which we operate while assuring the continuity of our business operations.

The Company's Consolidated Financial Statements reflect estimates and assumptions made by management that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements and reported amounts of revenue and expenses during the reporting periods presented. The Company considered the impacts of COVID-19 on the assumptions and estimates used and determined that, for the year ended December 31, 2020, there were no material adverse impacts on the Company's results of operations.

### Principles of Consolidation

The consolidated financial statements include the accounts of Black Hills Corporation and its wholly-owned and majority-owned and controlled subsidiaries. All intercompany balances and transactions have been eliminated in consolidation. For additional information on intercompany revenues, see Note 18.

Our Consolidated Statements of Income include operating activity of acquired companies beginning with their acquisition date. We use the proportionate consolidation method to account for our ownership interest in any jointly-owned electric utility generation facility, wind farm or transmission tie. See Note 6 for additional information.

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**Variable Interest Entities**

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

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

Our evaluation of whether our interest qualifies as the primary beneficiary of a VIE involves significant judgments, estimates and assumptions and includes a qualitative analysis of the activities that most significantly impact the VIE's economic performance and whether the Company has the power to direct those activities, the design of the entity, the rights of the parties and the purpose of the arrangement. Black Hills Colorado IPP is a VIE. See additional information in Note 14.

**Cash and Cash Equivalents and Restricted Cash**

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

**Accounts Receivable and Allowance for Credit Losses**

Accounts receivable for our Electric and Gas Utilities business segments primarily consists of sales to residential, commercial, industrial, transportation and other customers, all of which do not bear interest. These accounts receivable are stated at billed and estimated unbilled amounts, net of allowance for credit losses. Accounts receivable for our Power Generation and Mining business segments consists of amounts due from sales of electric energy and capacity and coal primarily to affiliates or regional utilities.

We maintain an allowance for credit losses which reflects our estimate of uncollectible trade receivables. We regularly review our trade receivable allowance by considering such factors as historical experience, credit worthiness, the age of the receivable balances and current economic conditions that may affect collectibility.

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

We utilize master netting agreements which consist of an agreement between two parties who have multiple contracts with each other that provide for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. Accounting standards also permit offsetting of fair value amounts recognized for the right to reclaim, or the obligation to return, cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty.

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

| 2020 | Billed Accounts Receivable | Unbilled Revenue | Less Allowance for Credit Losses | Accounts Receivable, net |
|---|---|---|---|---|
| Electric Utilities | $ 45,841 | $ 32,915 | $ (1,269) | $ 77,487 |
| Gas Utilities | 95,592 | 93,150 | (5,734) | 183,008 |
| Power Generation | 1,837 | — | — | 1,837 |
| Mining | 2,511 | — | — | 2,511 |
| Corporate | 1,118 | — | — | 1,118 |
| Total | $ 146,899 | $ 126,065 | $ (7,003) | $ 265,961 |

| 2019 | Billed Accounts Receivable | Unbilled Revenue | Less Allowance for Credit Losses | Accounts Receivable, net |
|---|---|---|---|---|
| Electric Utilities | $ 41,428 | $ 33,886 | $ (592) | $ 74,722 |
| Gas Utilities | 97,607 | 79,616 | (1,683) | 175,540 |
| Power Generation | 2,164 | — | — | 2,164 |
| Mining | 2,277 | — | — | 2,277 |
| Corporate | 1,271 | — | (169) | 1,102 |
| Total | $ 144,747 | $ 113,502 | $ (2,444) | $ 255,805 |

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

| | Balance at Beginning of Year | Additions Charged to Costs and Expenses | Recoveries and Other Additions | Write-offs and Other Deductions | Balance at End of Year |
|---|---|---|---|---|---|
| 2020 | $ 2,444 | $ 8,927 (a) | $ 4,728 | $ (9,096) | $ 7,003 |
| 2019 | $ 3,209 | $ 5,795 | $ 3,942 | $ (10,502) | $ 2,444 |
| 2018 | $ 3,081 | $ 6,859 | $ 4,092 | $ (10,823) | $ 3,209 |

(a) Due to the COVID-19 pandemic, all of our jurisdictions temporarily suspended disconnections due to non-payment for a period of time, which increased our accounts receivable arrears balances. As a result, we increased our allowance for credit losses and bad debt expense for the year ended December 31, 2020 by an incremental $3.3 million. The ongoing credit evaluation of our customers during the COVID-19 pandemic is further discussed in the Credit Risk section of Note 11.

**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 December 31 (in thousands):

| | 2020 | 2019 |
|---|---|---|
| Materials and supplies | $ 85,250 | $ 82,809 |
| Fuel | 1,531 | 2,425 |
| Natural gas in storage | 30,619 | 31,938 |
| Total materials, supplies and fuel | $ 117,400 | $ 117,172 |

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

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**Investments**

In February 2018, we made a contribution of $28 million of assets in exchange for equity securities in a privately held oil and gas company as we divested of our Oil and Gas segment. The carrying value of our investment in the equity securities was recorded at cost. We review this investment on a periodic basis to determine whether a significant event or change in circumstances has occurred that may have an adverse effect on the value of the investment.

During the third quarter of 2019, we assessed our investment for impairment as a result of a deterioration in earnings performance of the privately held oil and gas company and an adverse change in future natural gas prices. We engaged a third-party valuation consultant to estimate the fair value of our investment. The valuation was primarily based on an income approach but also considered a market valuation approach. The significant inputs used to estimate the fair value were the oil and gas reserve quantities and values utilizing forward market price curves, industry standard reserve adjustment factors and a discount rate of 10%. Based on the results of the valuation, we concluded that the carrying value of the investment exceeded fair value. As a result, we recorded a pre-tax impairment loss of $20 million for the three months ended September 30, 2019, which was the difference between the carrying amount and the fair value of the investment at that time.

During the first quarter of 2020, we assessed our investment for impairment as a result of continued adverse changes in future natural gas prices and liquidity concerns at the privately held oil and gas company. We performed an internal analysis to compute the fair value of our investment, utilizing a consistent methodology as applied during the third quarter of 2019. Based on the results of the valuation, we concluded that the carrying value of the investment exceeded fair value. As a result, we recorded a pre-tax impairment loss of $6.9 million for the three months ended March 31, 2020, which was the difference between the carrying value and the fair value of the investment at that time.

The following table presents the carrying value of our investments (in thousands), which are included in Other assets, non-current on the Consolidated Balance Sheets, as of December 31:

| | 2020 | 2019 |
|---|---|---|
| Investment in privately held oil and gas company | $ 1,500 | $ 8,359 |
| Cash surrender value of life insurance contracts | 13,628 | 13,056 |
| Other investments | 682 | 514 |
| Total investments | $ 15,810 | $ 21,929 |

We changed the classification of our investments on the Consolidated Balance Sheets as of December 31, 2019 to conform with current year presentation. The prior year reclassification of $22 million from Investments to Other assets, non-current did not impact previously reported current or total assets.

**Property, Plant and Equipment**

Additions to property, plant and equipment are recorded at cost. Included in the cost of regulated construction projects is AFUDC, when applicable, which represents the approximate composite cost of borrowed funds and a return on equity used to finance a regulated utility project. We also capitalize interest, when applicable, on undeveloped leasehold costs and certain non-regulated construction projects. In addition, asset retirement costs associated with tangible long-lived regulated utility assets are recognized as liabilities with an increase to the carrying amounts of the related long-lived regulated utility assets in the period incurred. The amounts capitalized are included in Property, plant and equipment on the accompanying Consolidated Balance Sheets. We also classify our stored natural gas base or Cushion Gas as property, plant and equipment.

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

Depreciation provisions for property, plant and equipment are generally computed on a straight-line basis based on the applicable estimated service life of the various classes of property. The composite depreciation method is applied to regulated utility property. Capitalized mining costs and coal leases are amortized on a unit-of-production method based on volumes produced and estimated reserves. For certain non-utility power plant components, depreciation is computed on a unit-of-production methodology based on plant hours run.

See Note 5 for additional information.

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**Asset Retirement Obligations**

Accounting standards for AROs associated with long-lived assets require that the present value of retirement costs for which we have a legal obligation be recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The associated ARO accretion expense for our non-regulated operations is included within Depreciation, depletion and amortization on the accompanying Consolidated Statements of Income. The accounting for the obligation for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset or a regulatory liability.

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

**Goodwill and Intangible Assets**

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

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

The Company has determined that the reporting units for its goodwill impairment test are its operating segments, which are also its reportable segments.

Our goodwill impairment analysis includes an income approach and a market approach to estimate the fair value of our reporting units. This analysis requires the input of several critical assumptions, including future growth rates, cash flow projections, operating cost escalation rates, rates of return, a risk-adjusted discount rate, timing and level of success in regulatory rate proceedings, the cost of debt and equity capital, long-term earnings and merger multiples for comparable companies.

We believe that goodwill reflects the inherent value of the relatively stable, long-lived cash flows of the regulated electric and gas utility businesses, considering the regulatory environment, and the long-lived cash flow and rate base growth opportunities at our utilities. Goodwill amounts have not changed since 2016. As of December 31, 2020 and 2019, Goodwill balances were as follows (in thousands):

| | Electric Utilities | Gas Utilities | Power Generation | Total |
|---|---|---|---|---|
| Goodwill | $ 248,479 | $ 1,042,210 | $ 8,765 | $ 1,299,454 |

Our intangible assets represent contract intangibles, easements, rights-of-way, customer listings and trademarks. The finite-lived intangible assets are amortized using a straight-line method based on estimated useful lives; these assets are currently being amortized from 2 years to 40 years. Changes to intangible assets for the years ended December 31, were as follows (in thousands):

| | 2020 | 2019 | 2018 |
|---|---|---|---|
| Intangible assets, net, beginning balance | $ 13,266 | $ 14,337 | $ 7,559 |
| Additions | — | — | 7,602 |
| Amortization expense [(a)] | (1,322) | (1,071) | (824) |
| Intangible assets, net, ending balance | $ 11,944 | $ 13,266 | $ 14,337 |

(a) Amortization expense for existing intangible assets is expected to be $1.3 million for each year of the next five years.

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**Accrued Liabilities**

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

| | 2020 | 2019 |
|---|---|---|
| Accrued employee compensation, benefits and withholdings | $ 77,806 | $ 62,837 |
| Accrued property taxes | 47,105 | 44,547 |
| Customer deposits and prepayments | 52,185 | 54,728 |
| Accrued interest | 31,520 | 31,868 |
| Other (none of which is individually significant) | 34,996 | 32,787 |
| Total accrued liabilities | $ 243,612 | $ 226,767 |

**Fair Value Measurements**

Financial Instruments

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

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

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

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

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

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

Valuation Methodologies for Derivatives

The wholesale electric energy and natural gas commodity contracts for our Utilities 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 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 CVA 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.

Additional information on fair value measurements is included in Notes 12 and 15.

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**Derivatives and Hedging Activities**

All our derivatives are measured at fair value and recognized as either assets or liabilities on the Consolidated Balance Sheets, except for derivative contracts that qualify for and are elected under the normal purchase and normal sales exception. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable amount of time and price is not tied to an unrelated underlying derivative. Normal purchase and sales contracts are recognized when the underlying physical transaction is completed under the accrual basis of accounting.

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

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

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

See additional information in Notes 11, 12 and 13.

**Deferred Financing Costs**

Deferred financing costs include loan origination fees, underwriter fees, legal fees and other costs directly attributable to the issuance of debt. Deferred financing costs are amortized over the estimated useful life of the related debt. These costs are presented on the balance sheet as an adjustment to the related debt liabilities. See additional information in Note 9.

**Regulatory Accounting**

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

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

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

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

As of December 31, 2020 and 2019, we had total regulatory assets of $278 million and $271 million respectively, and total regulatory liabilities of $533 million and $537 million respectively. See Note 2 for further information.

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**Income Taxes**

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

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

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

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

We account for uncertainty in income taxes recognized in the financial statements in accordance with the accounting standards for income taxes. The unrecognized tax benefit is classified in Other deferred credits and other liabilities or in Deferred income tax liabilities, net on the accompanying Consolidated Balance Sheets. See Note 17 for additional information.

**Earnings per Share of Common Stock**

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

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

| | 2020 | 2019 | 2018 |
|---|---|---|---|
| Net income available for common stock | $ 227,608 | $ 199,310 | $ 258,442 |
| Weighted average shares - basic | 62,378 | 60,662 | 54,420 |
| Dilutive effect of: | | | |
| Equity Units | — | — | 898 |
| Equity compensation | 61 | 136 | 168 |
| Weighted average shares - diluted | 62,439 | 60,798 | 55,486 |
| Net income available for common stock, per share - Diluted | $ 3.65 | $ 3.28 | $ 4.66 |

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

| | 2020 | 2019 | 2018 |
|---|---|---|---|
| Equity compensation | 60 | 1 | 16 |
| Anti-dilutive shares excluded from computation of earnings per share | 60 | 1 | 16 |

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**Noncontrolling Interests**

We account for changes in our controlling interests of subsidiaries according to ASC 810, *Consolidation.* ASC 810 requires that the Company record such changes as equity transactions, recording no gain or loss on such a sale. GAAP requires that noncontrolling interests in subsidiaries and affiliates be reported in the equity section of a company's balance sheet. In addition, the amounts attributable to the noncontrolling interest net income (loss) of those subsidiaries are reported separately in the consolidated statements of income and comprehensive income. See Note 14 for additional detail on noncontrolling interests.

**Share-Based Compensation**

We account for our share-based compensation arrangements in accordance with ASC 718, *Compensation-Stock Compensation*, by recognizing compensation costs for all share-based awards over the respective service period for employee services received in exchange for an award of equity or equity-based compensation. Awards that will be settled in stock are accounted for as equity and the compensation expense is based on the grant date fair value. Awards that are settled in cash are accounted for as liabilities and the compensation expense is re-measured each period based on the current market price and performance achievement measures. See additional information in Note 16.

**Change in Accounting Principle - Pension Accounting Asset Method**

Effective January 1, 2020, we changed our method of accounting for net periodic benefit cost. Prior to the change, the Company used a calculated value for determining market-related value of plan assets which amortized the effects of gains and losses over a five-year period. Effective with the accounting change, the Company will continue to use a calculated value for the return-seeking assets (equities) in the portfolio but was changed to fair value for the liability-hedging assets (fixed income). See Note 15 for additional information.

**Recently Issued Accounting Standards**

Facilitation of the Effects of Reference Rate Reform on Financial Reporting, ASU 2020-04

In March 2020, the FASB issued ASU 2020-04, *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting*, which was subsequently amended by ASU 2021-01. The standard provides relief for companies preparing for discontinuation of interest rates, such as LIBOR, and allows optional expedients and exceptions for applying GAAP to contracts, hedging relationships and other transactions affected by reference rate reform if certain criteria are met. The amendments in this update are elective and are effective upon the ASU issuance through December 31, 2022. We are currently evaluating if we will apply the optional guidance as we assess the impact of the discontinuance of LIBOR on our current arrangements and the potential impact on our financial position, results of operations and cash flows.

Simplifying the Accounting for Income Taxes, ASU 2019-12

In December 2019, the FASB issued ASU 2019-12, *Simplifying the Accounting for Income Taxes* as part of its overall simplification initiative to reduce costs and complexity in applying accounting standards while maintaining or improving the usefulness of the information provided to users of the financial statements. Amendments include removal of certain exceptions to the general principles of ASC 740, *Income Taxes*, and simplification in several other areas such as accounting for a franchise tax (or similar tax) that is partially based on income. The new guidance is effective for interim and annual periods beginning after December 15, 2020 with early adoption permitted. Adoption of this standard is not anticipated to have a material impact on our financial position, results of operations and cash flows.

**Recently Adopted Accounting Standards**

Financial Instruments -- Credit Losses: Measurement of Credit Losses on Financial Instruments, ASU 2016-13

In June 2016, the FASB issued ASU 2016-13, *Financial Instruments -- Credit Losses: Measurement of Credit Losses on Financial Instruments,* which was subsequently amended by ASU 2018-19, ASU 2019-04, 2019-05, 2019-10, and 2019-11. The standard introduces new accounting guidance for credit losses on financial instruments within its scope, including trade receivables. This new guidance adds an impairment model that is based on expected losses rather than incurred losses.

We adopted this standard on January 1, 2020 with prior year comparative financial information remaining as previously reported when transitioning to the new standard. On January 1, 2020, we recorded an increase to our allowance for credit losses, primarily associated with the inclusion of expected losses on unbilled revenue. The cumulative effect of the adoption, net of tax impact, was $0.2 million, which was recorded as an adjustment to retained earnings.

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Simplifying the Test for Goodwill Impairment, ASU 2017-04

In January 2017, the FASB issued ASU 2017-04, *Simplifying the Test for Goodwill Impairment* by eliminating step 2 from the goodwill impairment test. Under the new guidance, if the carrying amount of a reporting unit exceeds its fair value, an impairment loss will be recognized in an amount equal to that excess, limited to the amount of goodwill allocated to that reporting unit. We adopted this standard prospectively on January 1, 2020. Adoption of this guidance did not have any impact on our financial position, results of operations or cash flows.

Internal-Use Software: Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract, ASU 2018-15

In August 2018, the FASB issued ASU 2018-15, *Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract*, which aligns the requirements for recording implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. As a result, certain categories of implementation costs that previously would have been charged to expense as incurred are now capitalized as prepayments and amortized over the term of the arrangement. We adopted this standard prospectively on January 1, 2020. Adoption of this guidance did not have a material impact on our financial position, results of operations or cash flows.

**(2) REGULATORY MATTERS**

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

| | 2020 | 2019 |
|---|---|---|
| **Regulatory assets** | | |
| Deferred energy and fuel cost adjustments [a] | $ 39,035 | $ 34,088 |
| Deferred gas cost adjustments [a] | 3,200 | 1,540 |
| Gas price derivatives [a] | 2,226 | 3,328 |
| Deferred taxes on AFUDC [b] | 7,491 | 7,790 |
| Employee benefit plans and related deferred taxes [c] | 116,598 | 115,900 |
| Environmental [a] | 1,413 | 1,454 |
| Loss on reacquired debt [a] | 22,864 | 24,777 |
| Renewable energy standard adjustment [a] | — | 1,622 |
| Deferred taxes on flow-through accounting [c] | 47,515 | 41,220 |
| Decommissioning costs [a] | 8,988 | 10,670 |
| Gas supply contract termination [a] | 2,524 | 8,485 |
| Other regulatory assets [a] | 26,404 | 20,470 |
| Total regulatory assets | 278,258 | 271,344 |
| Less current regulatory assets | (51,676) | (43,282) |
| Regulatory assets, non-current | $ 226,582 | $ 228,062 |
| | | |
| **Regulatory liabilities** | | |
| Deferred energy and gas costs [a] | $ 13,253 | $ 17,278 |
| Employee benefit plan costs and related deferred taxes [c] | 40,256 | 43,349 |
| Cost of removal [a] | 172,902 | 166,727 |
| Excess deferred income taxes [c] | 285,259 | 285,438 |
| Other regulatory liabilities [c] | 21,050 | 23,860 |
| Total regulatory liabilities | 532,720 | 536,652 |
| Less current regulatory liabilities | (25,061) | (33,507) |
| Regulatory liabilities, non-current | $ 507,659 | $ 503,145 |

(a) Recovery of costs, but we are not allowed a rate of return.
(b) In addition to recovery of costs, we are allowed a rate of return.
(c) In addition to recovery or repayment of costs, we are allowed a return on a portion of this amount or a reduction in rate base.

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

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

Deferred Gas Cost Adjustments - Our regulated Gas Utilities have GCA provisions that allow them to pass the cost of gas on to their customers. The GCA is based on forecasts of the upcoming gas costs and recovery or refund of prior under-recovered or over-recovered costs. To the extent that gas costs are under-recovered or over-recovered, they are recorded as a regulatory asset or liability, respectively. Our Gas Utilities file periodic estimates of future gas costs based on market forecasts with state regulatory commissions. The recovery period for these costs is less than a year.

Gas Price Derivatives - Our regulated Gas Utilities, as allowed or required by state regulatory commissions, have entered into certain exchange-traded natural gas futures and options to reduce our customers' underlying exposure to fluctuations in gas prices. Gas price derivatives represent our unrealized positions on our commodity contracts supporting our utilities. Gas price derivatives at December 31, 2020 are hedged over a maximum forward term of two years.

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

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

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

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

Renewable Energy Standard Adjustment - The renewable energy standard adjustment provides funding for various renewable energy projects and programs to comply with Colorado's Renewable Energy Standard. These programs include incentives for our Colorado Electric customers to install renewable energy equipment at their location. These project costs and program incentives are recovered over time through the Renewable Energy Standard Adjustment charged on customers' bills.

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

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

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Gas Supply Contract Termination - As part of our acquisition of SourceGas in 2016, we acquired agreements that required the Company to purchase all of the natural gas produced over the productive life of specific leaseholds in the Bowdoin Field in Montana. The majority of these purchases were committed to certain customers in Colorado, Nebraska, and Wyoming, which are subject to cost recovery mechanisms. The prices to be paid under these agreements varied, ranging from $6 to $8 per MMBtu at the time of acquisition, which exceeded market prices. We recorded a liability for this contract in our SourceGas Transaction purchase price allocation. We were granted approval to terminate these agreements from the CPUC, NPSC and WPSC on the basis that these agreements were not beneficial to customers over the long term. We received written orders allowing us to create a regulatory asset for the net buyout costs associated with the contract termination, and recover the majority of costs from customers over a period of five years. We terminated the contract and settled the liability on April 29, 2016.

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

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

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

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

Excess Deferred Income Taxes - The revaluation of the regulated utilities' deferred tax assets and liabilities due to the passage of the TCJA was recorded as an excess deferred income tax to be refunded to customers primarily using the normalization principles as prescribed in the TCJA. See Note 17 for additional information.

**Regulatory Activity**

*TCJA*

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the TCJA. The TCJA reduced the U.S. federal corporate tax rate from 35% to 21%. As such, the Company remeasured our deferred income taxes at the 21% federal tax rate as of December 31, 2017. In 2018 and 2019, the Company successfully delivered several of these tax benefits from the TCJA to its utility customers.

In 2020, regulatory proceedings resolved the last of the Company's open dockets seeking approval of its TCJA plans. As a result, the Company relieved certain TCJA-related liabilities, which resulted in an increase to net income for the year ended December 31, 2020 of $4.0 million.

On December 30, 2020, an administrative law judge approved a settlement of Colorado Electric's plan to provide $9.3 million of TCJA-related customer billing credits to its customers. The billing credits, which represent a disposition of excess deferred income tax benefits resulting from the TCJA, will be delivered to customers in February 2021. These billing credits will be offset by a reduction in income tax expense and will result in a minimal impact to Net income.

On Janaury 26, 2021, NPSC approved Nebraska Gas's plan to provide $2.9 million of TCJA-related customer billing credits to its customers. The billing credits, which represent a disposition of excess deferred income tax benefits resulting from the TCJA, is expected to be delivered to customers in the second quarter of 2021. These billing credits will be offset by a reduction in income tax and and will result in a minimal impact to Net income.

**Electric Utilities Regulatory Activity**

*South Dakota Electric*

*Settlement*

On January 7, 2020, South Dakota Electric received approval from the SDPUC on a settlement agreement to extend the 6-year moratorium period by an additional 3 years to June 30, 2026. Also, as part of the settlement, we withdrew our application for deferred accounting treatment and expensed $5.4 million of development costs in 2019 related to projects we no longer intend to construct. This settlement amends a previous agreement approved by the SDPUC on June 16, 2017, whereby South Dakota Electric would not increase base rates, absent an extraordinary event, for a 6 year moratorium period effective July 1, 2017. The moratorium period also includes suspension of both the TFA and EIA.

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*FERC Formula Rate*

The annual rate determination process is governed by the FERC formula rate protocols established in the filed FERC joint-access transmission tariff. Effective January 1, 2020 the annual revenue requirement was $27 million and included estimated weighted average capital additions of $33 million for 2019 and 2020 combined. The annual transmission revenue requirement has a true-up mechanism that is recorded in June of each year.

*Black Hills Wyoming and Wyoming Electric*

*Wygen 1 FERC Filing*

On October 15, 2020, the FERC approved a settlement agreement that represents a resolution of all issues in the joint application filed by Wyoming Electric and Black Hills Wyoming on August 2, 2019 for approval of a new 60 MW PPA. Under the terms of the settlement, Wyoming Electric will continue to receive 60 MW of capacity and energy from the Wygen I power plant. The new agreement will commence on January 1, 2022, replace the existing PPA and continue for 11 years.

**Gas Utilities Regulatory Activity**

*Colorado Gas*

*Jurisdictional Consolidation and Rate Reviews*

On September 11, 2020, Colorado Gas filed a rate review with the CPUC seeking recovery on significant infrastructure investments in its 7,000-mile natural gas pipeline system. The rate review requests $13.5 million in new annual revenue with a capital structure of 50% equity and 50% debt and a return on equity of 9.95%. The request seeks to implement new rates in the second quarter of 2021. On January 6, 2021 the CPUC issued an order dismissing the rate review. On January 26, 2021, Colorado Gas filed an application for rehearing, reargument or reconsideration in response to the Commission's January 6 order.

On September 11, 2020, in accordance with the final order from the earlier rate review discussed below, Colorado Gas also filed a new SSIR proposal that would recover safety and integrity focused investments in its system over five years. A decision from the CPUC is expected by mid-2021.

On February 1, 2019, Colorado Gas filed a rate review with the CPUC requesting $2.5 million in new revenue to recover investments in safety, reliability and system integrity and approval to consolidate rates, tariffs, and services of its two existing gas distribution territories. Colorado Gas also requested a new rider mechanism to recover future safety and integrity investments in its system. On May 19, 2020, the CPUC issued a final order which denied the system integrity recovery mechanism and consolidation of rate territories. In addition, the order resulted in an annual revenue decrease of $0.6 million and a return on equity of 9.2%. New rates were effective July 3, 2020.

*RMNG SSIR*

On October 30, 2020, RMNG filed the tariff adjusting rates to include 2021 projects with an expected capital investment of $33 million under the current SSIR. The new tariff rates went into effect January 1, 2021 and the current approved SSIR expires December 31, 2021.

*Nebraska Gas*

*Jurisdictional Consolidation and Rate Review*

On January 26, 2021, Nebraska Gas received approval from the NPSC to consolidate rate schedules into a new, single statewide structure and recover significant infrastructure investments in its 13,000-mile natural gas pipeline system. Final rates will be enacted on March 1, 2021, to replace interim rates enacted September 1, 2020. The approval will shift $4.6 million of SSIR revenue to base rates and is expected to generate $6.5 million in new annual revenue with a capital structure of 50% equity and 50% debt and a return on equity of 9.5%. The approval also includes an extension of the SSIR for five years and an expansion of this mechanism for consolidated utility alignment.

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*Wyoming Gas*

*Jurisdictional Consolidation and Rate Review*

Wyoming Gas's new single statewide rate structure became effective March 1, 2020. Wyoming Gas received approval from the WPSC on December 11, 2019, to consolidate the rates, tariffs and services of its four existing gas distribution territories. New rates are expected to generate $13 million in new annual revenue based on a return on equity of 9.40% and a capital structure of 50.23% equity and 49.77% debt. The approval also allows for a rider to recover integrity investments for system safety and reliability.

**(3) COMMITMENTS, CONTINGENCIES AND GUARANTEES**

**Power Purchase and Transmission Services Agreements**

Through our subsidiaries, we have the following significant long-term power purchase contracts and transmission services agreement (TSA) with non-affiliated third-parties:

| Subsidiary | Contract Type | Counterparty | Fuel Type | Quantity (MW) | Expiration Date |
|---|---|---|---|---|---|
| Colorado Electric [(a)] | PPA | PRPA | Wind | 60 | May 31, 2030 |
| Colorado Electric | PPA | PRPA | Coal | 25 | June 30, 2024 |
| South Dakota Electric | PPA | PacifiCorp | Coal | 50 | December 31, 2023 |
| South Dakota Electric [(b)] | TSA | PacifiCorp | N/A | 50 | December 31, 2023 |
| South Dakota Electric | PPA | PRPA | Wind | 12 | September 30, 2029 |
| South Dakota Electric | PPA | Fall River Solar, LLC | Solar | 80 | Pending Completion [(c)] |
| Wyoming Electric [(d)] | PPA | Happy Jack | Wind | 30 | September 3, 2028 |
| Wyoming Electric [(e)] | PPA | Silver Sage | Wind | 30 | September 30, 2029 |

(a) Colorado Electric sells the wind energy purchased under this PPA to City of Colorado Springs as discussed below.
(b) This is a firm point-to-point transmission service agreement that provides 50 MW of capacity and energy to be transmitted annually.
(c) This agreement relates to a new solar facility currently being constructed and will expire 20 years after construction completion, which is expected by the end of 2022.
(d) Under a separate intercompany PSA, Wyoming Electric sells 50% of the facility output to South Dakota Electric.
(e) Under a separate intercompany PSA, Wyoming Electric sells 67% of the facility output to South Dakota Electric.

Costs under these agreements for the years ended December 31 were as follows (in thousands):

| Subsidiary | Contract Type | Counterparty | Fuel Type | 2020 | 2019 | 2018 |
|---|---|---|---|---|---|---|
| Colorado Electric | PPA | PRPA | Wind | $ 2,791 | $ — | $ — |
| Colorado Electric | PPA | PRPA | Coal | $ 4,524 | $ 1,802 | $ — |
| South Dakota Electric | PPA | PacifiCorp | Coal | $ 5,897 | $ 7,477 | $ 13,681 |
| South Dakota Electric | TSA | PacifiCorp | N/A | $ 1,776 | $ 1,741 | $ 1,742 |
| South Dakota Electric | PPA | PRPA | Wind | $ 715 | $ 688 | $ 223 |
| Wyoming Electric | PPA | Happy Jack | Wind | $ 4,531 | $ 3,936 | $ 3,884 |
| Wyoming Electric | PPA | Silver Sage | Wind | $ 6,203 | $ 5,366 | $ 5,376 |

**Power Purchase Agreements - Related Parties**

Wyoming Electric currently has a PPA with Black Hills Wyoming expiring on December 31, 2022, which provides 60 MW of unit-contingent capacity and energy from Black Hills Wyoming's Wygen I facility. On October 15, 2020, the FERC approved a settlement agreement in the joint application filed by Wyoming Electric and Black Hills Wyoming on August 2, 2019 for approval of a new 60 MW PPA. Under the terms of the settlement, Wyoming Electric will continue to receive 60 MW of capacity and energy from the Wygen I facility. The new agreement will commence on January 1, 2022, replace the existing PPA and continue for 11 years.

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Black Hills Electric Generation provides the wind energy generated from Busch Ranch II to Colorado Electric through a PPA, which expires in November 2044.

Black Hills Electric Generation provides its 14.5 MW share of energy generated from Busch Ranch I to Colorado Electric through a PPA, which expires in October 2037.

Colorado Electric's PPA with Black Hills Colorado IPP expiring on December 31, 2031, provides 200 MW of power to Colorado Electric from Black Hills Colorado IPP's combined-cycle turbines. At the segment level, we recognize the associated revenues, costs and assets on an accrual basis, rather than as a finance lease. See Note 18 for additional information.

**Purchase Commitments**

We maintain natural gas supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated baseload gas volumes are established prior to the beginning of the month under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month based on requirements in accordance with the terms of the individual contract.

Our Gas Utilities segment has commitments to purchase physical quantities of natural gas under contracts indexed to various forward natural gas price curves. A portion of our gas purchases are purchased under evergreen contracts and are therefore, for purposes of this disclosure, carried out for 60 days. At December 31, 2020, the long-term commitments to purchase quantities of natural gas under contracts indexed to the following forward indices were as follows (in MMBtus):

| | Northern Natural Gas - Ventura | Northwest Pipeline - Wyoming | ONEOK - Oklahoma | Southern Star Central Gas Pipeline | Panhandle Eastern Pipe Line |
|---|---|---|---|---|---|
| 2021 | 3,650,000 | 1,510,000 | 5,475,000 | 113,130 | 4,680 |
| 2022 | 1,810,000 | 1,510,000 | 5,475,000 | — | — |
| 2023 | 1,840,000 | 1,510,000 | 5,475,000 | — | — |
| 2024 | 1,820,000 | 910,000 | 5,490,000 | — | — |
| 2025 | — | — | 4,560,000 | — | — |
| Thereafter | — | — | — | — | — |

Purchases under these contracts totaled $25 million, $6.7 million and $27 million for 2020, 2019 and 2018, respectively.

**Other Gas Supply Agreements**

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

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

| | Power purchase and transmission services agreements (a) | Natural gas transportation and storage agreements |
|---|---|---|
| 2021 | $ 24,452 | $ 116,563 |
| 2022 | $ 11,678 | $ 121,819 |
| 2023 | $ 11,678 | $ 100,282 |
| 2024 | $ 2,738 | $ 67,089 |
| 2025 | $ — | $ 50,709 |
| Thereafter | $ — | $ 167,100 |

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

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**Power Sales Agreements**

Through our subsidiaries, we have the following significant long-term power sales contracts with non-affiliated third-parties:

- On July 1, 2020, Colorado Electric entered into a PSA with the City of Colorado Springs to sell up to 60 MW of wind energy purchased from PRPA under a separate 60 MW PPA discussed above. This PSA with the City of Colorado Springs expires June 30, 2025.
- During periods of reduced production at Wygen III in which MDU owns a portion of the capacity, or during periods when Wygen III is off-line, South Dakota Electric will provide MDU with 25 MW from our other generation facilities or from system purchases with reimbursement of costs by MDU. This agreement expires January 31, 2023.
- South Dakota Electric has an agreement to provide MDU capacity and energy up to a maximum of 50 MW in excess of Wygen III ownership. This agreement expires December 31, 2023.
- During periods of reduced production at Wygen III in which the City of Gillette owns a portion of the capacity, or during periods when Wygen III is off-line, South Dakota Electric will provide the City of Gillette with its first 23 MW from its other generating facilities or from system purchases with reimbursement of costs by the City of Gillette. Under this agreement, which has an initial term through September 3, 2034 and would be renewed annually on September 3 thereafter, South Dakota Electric will also provide the City of Gillette their operating component of spinning reserves.
- South Dakota Electric has an amended agreement, effective January 1, 2019, to supply up to 20 MW of energy and capacity to MEAN under a contract that expires May 31, 2028. The contract terms are from June 1 through May 31 for each interval listed below. This contract is unit-contingent based on the availability of our Neil Simpson II and Wygen III plants, with decreasing capacity purchased over the term of the agreement. The unit-contingent capacity amounts from Wygen III and Neil Simpson II are as follows:

| Contract Years | Total Contract Capacity | Contingent Capacity Amounts on Wygen III | Contingent Capacity Amounts on Neil Simpson II |
|---|---|---|---|
| 2020-2022 | 15 MW | 7 MW | 8 MW |
| 2022-2023 | 15 MW | 8 MW | 7 MW |
| 2023-2028 | 10 MW | 5 MW | 5 MW |

- South Dakota Electric has an agreement that expires December 31, 2021 to provide 50 MW of energy to Macquarie Energy, LLC during heavy and light load timing intervals.
- Black Hills Wyoming sold its CTII 40 MW natural gas-fired generating unit to the City of Gillette, Wyoming on September 3, 2014. Under the terms of the sale, Black Hills Wyoming entered into ancillary agreements to operate CTII, provide use of shared facilities including a ground lease and dispatch generation services. In addition, the agreement includes a 20-year economy energy PSA that contains a sharing arrangement in which the parties share the savings of wholesale power purchases made when market power prices are less than the cost of operating the generating unit.

**Environmental Matters**

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

*Reclamation Liability*

For our Pueblo Airport Generation site, we posted a bond of $4.1 million with the State of Colorado to cover the costs of remediation for a waste water containment pond permitted to provide wastewater storage and processing for this zero discharge facility. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land.

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

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

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See Note 7 for additional information.

*Manufactured Gas Processing*

In 2008, we acquired whole and partial liabilities for former manufactured gas processing sites in Nebraska and Iowa which were previously used to convert coal to natural gas. The acquisition provided for an insurance recovery, now valued at $1.2 million recorded in Other assets, non-current on our Consolidated Balance Sheets, which will be used to help offset remediation costs. We also have a $1.4 million regulatory asset for manufactured gas processing sites; see Note 2 for additional information.

As of December 31, 2020, we had $2.6 million accrued for remediation of Iowa's manufactured gas processing site as the landowner. As of December 31, 2020, we had $0.6 million accrued for remediation of Nebraska's manufactured gas processing site as the land owner. These liabilities are included in Other deferred credits and other liabilities on our Consolidated Balance Sheets. The remediation cost estimate could change materially due to results of further investigations, actions of environmental agencies or the financial viability of other responsible parties.

**Legal Proceedings**

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

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

**Guarantees**

We have entered into various agreements providing financial or performance assurance to third parties on behalf of certain of our subsidiaries. The agreements, which are off-balance sheet commitments, include indemnification for reclamation and surety bonds. The guarantees were entered into in the normal course of business. To the extent liabilities are incurred as a result of activities covered by the surety bonds, such liabilities are included in our Consolidated Balance Sheets.

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

| Nature of Guarantee | Maximum Exposure at December 31, 2020 | | Expiration |
|---|---|---|---|
| Indemnification for subsidiary reclamation/surety bonds | $ | 53,769 | Ongoing |

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## (4) REVENUE

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

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

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

- Coal supply agreements - Our Mining segment sells coal primarily under long-term contracts to utilities for use at their power generating plants, including affiliate Electric Utilities, and an affiliate non-regulated Power Generation entity. The contracts include a single promise to supply coal necessary to fuel the customers' facilities during the contract term. The transaction price is established in the supply agreements, including cost-based agreements with the affiliated regulated utilities, and is variable based on tons delivered.

- Other non-regulated services - Our Electric and Gas Utilities segments also provide non-regulated services primarily comprised of appliance repair service and protection plans, electric and natural gas technical infrastructure construction and maintenance services, and in Nebraska and Wyoming, an unbundled natural gas commodity offering under the regulatory-approved Choice Gas Program. Revenue contracts for these services generally represent a single performance obligation with the price reflecting the standalone selling price stated in the agreement, and the revenue is variable based on the units delivered or services provided.

The following tables depict the disaggregation of revenue, including intercompany revenue, from contracts with customers by customer type and timing of revenue recognition for each of the reportable segments, for the years ended December 31, 2020, 2019 and 2018. Sales tax and other similar taxes are excluded from revenues.

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| Year ended December 31, 2020 | Electric Utilities | Gas Utilities | Power Generation | Mining | Inter-company Revenues | Total |
|---|---|---|---|---|---|---|
| Customer types: | | | (in thousands) | | | |
| Retail | $ 610,721 | $ 765,922 | $ — | $ 58,567 | $ (31,478) | $ 1,403,732 |
| Transportation | — | 154,581 | — | — | (526) | 154,055 |
| Wholesale | 17,848 | — | 103,258 | — | (97,169) | 23,937 |
| Market - off-system sales | 24,309 | 260 | — | — | (8,797) | 15,772 |
| Transmission/Other | 58,965 | 43,658 | — | — | (19,315) | 83,308 |
| Revenue from contracts with customers | 711,843 | 964,421 | 103,258 | 58,567 | (157,285) | 1,680,804 |
| Other revenues | 2,201 | 10,249 | 1,789 | 2,508 | (610) | 16,137 |
| Total revenues | $ 714,044 | $ 974,670 | $ 105,047 | $ 61,075 | $ (157,895) | $ 1,696,941 |
| | | | | | | |
| Timing of revenue recognition: | | | | | | |
| Services transferred at a point in time | $ — | $ — | $ — | $ 58,567 | $ (31,478) | $ 27,089 |
| Services transferred over time | 711,843 | 964,421 | 103,258 | — | (125,807) | 1,653,715 |
| Revenue from contracts with customers | $ 711,843 | $ 964,421 | $ 103,258 | $ 58,567 | $ (157,285) | $ 1,680,804 |

| Year ended December 31, 2019 | Electric Utilities | Gas Utilities | Power Generation | Mining | Inter-company Revenues | Total |
|---|---|---|---|---|---|---|
| Customer types: | | | (in thousands) | | | |
| Retail | $ 605,756 | $ 817,840 | $ — | $ 59,233 | $ (32,053) | $ 1,450,776 |
| Transportation | — | 143,390 | — | — | (1,042) | 142,348 |
| Wholesale | 20,884 | — | 99,157 | — | (91,577) | 28,464 |
| Market - off-system sales | 23,817 | 691 | — | — | (7,736) | 16,772 |
| Transmission/Other | 57,104 | 47,725 | — | — | (16,797) | 88,032 |
| Revenue from contracts with customers | 707,561 | 1,009,646 | 99,157 | 59,233 | (149,205) | 1,726,392 |
| Other revenues | 5,191 | 384 | 2,101 | 2,396 | (1,564) | 8,508 |
| Total revenues | $ 712,752 | $ 1,010,030 | $ 101,258 | $ 61,629 | $ (150,769) | $ 1,734,900 |
| | | | | | | |
| Timing of revenue recognition: | | | | | | |
| Services transferred at a point in time | $ — | $ — | $ — | $ 59,233 | $ (32,053) | $ 27,180 |
| Services transferred over time | 707,561 | 1,009,646 | 99,157 | — | (117,152) | 1,699,212 |
| Revenue from contracts with customers | $ 707,561 | $ 1,009,646 | $ 99,157 | $ 59,233 | $ (149,205) | $ 1,726,392 |

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| Year ended December 31, 2018 | Electric Utilities | Gas Utilities | Power Generation | Mining | Inter-company Revenues | Total |
|---|---|---|---|---|---|---|
| Customer types: | | | (in thousands) | | | |
| Retail | $ 594,329 | $ 833,379 | $ — | $ 65,803 | $ (32,194) | $ 1,461,317 |
| Transportation | — | 140,705 | — | — | (1,348) | 139,357 |
| Wholesale | 33,687 | — | 90,791 | — | (84,957) | 39,521 |
| Market - off-system sales | 24,799 | 866 | — | — | (8,102) | 17,563 |
| Transmission/Other | 56,209 | 49,402 | — | — | (14,827) | 90,784 |
| Revenue from contracts with customers | 709,024 | 1,024,352 | 90,791 | 65,803 | (141,428) | 1,748,542 |
| Other revenues | 2,427 | 955 | 1,660 | 2,230 | (1,546) | 5,726 |
| Total revenues | $ 711,451 | $ 1,025,307 | $ 92,451 | $ 68,033 | $ (142,974) | $ 1,754,268 |
| | | | | | | |
| Timing of revenue recognition: | | | | | | |
| Services transferred at a point in time | $ — | $ — | $ — | $ 65,803 | $ (32,194) | $ 33,609 |
| Services transferred over time | 709,024 | 1,024,352 | 90,791 | — | (109,234) | 1,714,933 |
| Revenue from contracts with customers | $ 709,024 | $ 1,024,352 | $ 90,791 | $ 65,803 | $ (141,428) | $ 1,748,542 |

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

Revenue Not in Scope of ASC 606

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

Significant Judgments and Estimates

*Unbilled Revenue*

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

*Contract Balances*

The nature of our primary revenue contracts provides an unconditional right to consideration upon service delivery; therefore, no customer contract assets or liabilities exist. The unconditional right to consideration is represented by the balance in our Accounts Receivable further discussed in Note 1.

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## (5) PROPERTY, PLANT AND EQUIPMENT

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

| | 2020 | | 2019 | | Lives (in years) | |
|---|---|---|---|---|---|---|
| Electric Utilities | Property, Plant and Equipment | Weighted Average Useful Life (in years) | Property, Plant and Equipment | Weighted Average Useful Life (in years) | Minimum | Maximum |
| Electric plant: | | | | | | |
| Production | $ 1,417,951 | 40 | $ 1,348,049 | 41 | 32 | 46 |
| Electric transmission | 517,794 | 49 | 483,640 | 51 | 44 | 51 |
| Electric distribution | 959,453 | 46 | 861,042 | 47 | 46 | 48 |
| Plant acquisition adjustment (a) | 4,870 | 32 | 4,870 | 32 | 32 | 32 |
| General | 259,010 | 28 | 259,266 | 28 | 26 | 29 |
| Total electric plant in service | 3,159,078 | | 2,956,867 | | | |
| Construction work in progress | 89,402 | | 102,268 | | | |
| Total electric plant | 3,248,480 | | 3,059,135 | | | |
| Less accumulated depreciation | (666,669) | | (670,861) | | | |
| Electric plant net of accumulated depreciation | $ 2,581,811 | | $ 2,388,274 | | | |

(a) The plant acquisition adjustment is included in rate base and is being recovered with 10 years remaining.

| | 2020 | | 2019 | | Lives (in years) | |
|---|---|---|---|---|---|---|
| Gas Utilities | Property, Plant and Equipment | Weighted Average Useful Life (in years) | Property, Plant and Equipment | Weighted Average Useful Life (in years) | Minimum | Maximum |
| Gas plant: | | | | | | |
| Production | $ 15,603 | 40 | $ 13,000 | 35 | 24 | 46 |
| Gas transmission | 578,278 | 54 | 516,172 | 50 | 22 | 71 |
| Gas distribution | 2,115,082 | 53 | 1,857,233 | 43 | 45 | 59 |
| Cushion gas - depreciable (a) | 3,539 | 28 | 3,539 | 28 | 28 | 28 |
| Cushion gas - not depreciable (a) | 39,184 | N/A | 44,443 | N/A | N/A | N/A |
| Storage | 55,481 | 38 | 46,977 | 31 | 24 | 52 |
| General | 438,217 | 19 | 437,054 | 20 | 12 | 23 |
| Total gas plant in service | 3,245,384 | | 2,918,418 | | | |
| Construction work in progress | 67,229 | | 63,080 | | | |
| Total gas plant | 3,312,613 | | 2,981,498 | | | |
| Less accumulated depreciation | (323,679) | | (336,721) | | | |
| Gas plant net of accumulated depreciation | $ 2,988,934 | | $ 2,644,777 | | | |

(a) Depreciation of Cushion Gas is determined by the respective regulatory jurisdiction in which the Cushion Gas resides.

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| 2020 | Property, Plant and Equipment | Construction Work in Progress | Total Property Plant and Equipment | Less Accumulated Depreciation and Depletion | Net Property, Plant and Equipment | Weighted Average Useful Life | Lives (in years) Minimum | Lives (in years) Maximum |
|---|---|---|---|---|---|---|---|---|
| Power Generation | $ 529,927 | $ 4,876 | $ 534,803 | $ (167,787) | $ 367,016 | 31 | 2 | 40 |
| Mining | $ 186,552 | $ 988 | $ 187,540 | $ (126,537) | $ 61,003 | 14 | 2 | 59 |

| 2019 | Property, Plant and Equipment | Construction Work in Progress | Total Property Plant and Equipment | Less Accumulated Depreciation and Depletion | Net Property, Plant and Equipment | Weighted Average Useful Life | Lives (in years) Minimum | Lives (in years) Maximum |
|---|---|---|---|---|---|---|---|---|
| Power Generation | $ 532,397 | $ 2,121 | $ 534,518 | $ (154,362) | $ 380,156 | 31 | 2 | 40 |
| Mining | $ 179,198 | $ 1,275 | $ 180,473 | $ (118,585) | $ 61,888 | 13 | 2 | 59 |

| 2020 | Property, Plant and Equipment | Construction Work in Progress | Total Property Plant and Equipment | Less Accumulated Depreciation | Net Property, Plant and Equipment | Weighted Average Useful Life | Lives (in years) Minimum | Lives (in years) Maximum |
|---|---|---|---|---|---|---|---|---|
| Corporate | $ 5,692 | $ 16,402 | $ 22,094 | $ (1,144) | $ 20,950 | 10 | 10 | 22 |

| 2019 | Property, Plant and Equipment | Construction Work in Progress | Total Property Plant and Equipment | Less Accumulated Depreciation | Net Property, Plant and Equipment | Weighted Average Useful Life | Lives (in years) Minimum | Lives (in years) Maximum |
|---|---|---|---|---|---|---|---|---|
| Corporate | $ 5,721 | $ 23,334 | $ 29,055 | $ (964) | $ 28,091 | 10 | 3 | 30 |

## (6) JOINTLY OWNED FACILITIES

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

*Wyodak Plant*

South Dakota Electric owns a 20% interest in the Wyodak Plant, a coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp owns the remaining ownership percentage and operates the Wyodak Plant. South Dakota Electric receives its proportionate share of the Wyodak Plant's capacity and is committed to pay its proportionate share of its additions, replacements and operating and maintenance expenses. In addition to supplying South Dakota Electric with coal for its share of the Wyodak Plant, our Mining subsidiary, WRDC, supplies PacifiCorp's share of the coal to the Wyodak Plant under a separate long-term agreement. This coal supply agreement is collateralized by a mortgage on and a security interest in some of WRDC's coal reserves.

*Transmission Tie*

South Dakota Electric also owns a 35% interest in, and is the operator of, the Converter Station Site and South Rapid City Interconnection (the Transmission Tie), an AC-DC-AC transmission tie. Basin Electric Power Cooperative owns the remaining ownership percentage. South Dakota Electric is committed to pay its proportionate share of the additions and replacements and operating and maintenance expenses of the transmission tie.

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*Wygen III*

South Dakota Electric owns 52% of the Wygen III generation facility. MDU and the City of Gillette each owns an undivided ownership interest in Wygen III and are obligated to make payments for costs associated with administrative services and their proportionate share of the costs of operating the plant for the life of the facility. South Dakota Electric retains responsibility for plant operations. Our Mining subsidiary supplies fuel to Wygen III for the life of the plant.

*Wygen I*

Black Hills Wyoming owns 76.5% of the Wygen I plant while MEAN owns the remaining ownership percentage. MEAN is obligated to make payments for its share of the costs associated with administrative services, plant operations and coal supply provided by our Mining subsidiary during the life of the facility. Black Hills Wyoming retains responsibility for plant operations.

At December 31, 2020, our interests in jointly-owned generating facilities and transmission systems were (in thousands):

| | Plant in Service | Construction Work in Progress | Less Accumulated Depreciation | Plant Net of Accumulated Depreciation |
|---|---|---|---|---|
| Wyodak Plant | $ 116,074 | $ 2,249 | $ (67,762) | $ 50,561 |
| Transmission Tie | $ 26,176 | $ 509 | $ (7,103) | $ 19,582 |
| Wygen III | $ 142,739 | $ 582 | $ (24,783) | $ 118,538 |
| Wygen I | $ 114,975 | $ 318 | $ (49,459) | $ 65,834 |

**Jointly Owned Facilities - Related Party**

*Busch Ranch I*

Colorado Electric owns 50% of Busch Ranch I while Black Hills Electric Generation owns the remaining 50% ownership interest. Each company is obligated to make payments for costs associated with their proportionate share of the costs of operating the wind farm over the life of the facility. Colorado Electric retains responsibility for operations of the wind farm. Black Hills Electric Generation provides its share of energy from the wind farm to Colorado Electric through a PPA, which expires in October 2037.

*Cheyenne Prairie*

Cheyenne Prairie serves the utility customers of South Dakota Electric and Wyoming Electric. The facility includes one simple-cycle, 37 MW combustion turbine that is wholly-owned by Wyoming Electric and one combined-cycle, 100.4 MW unit that is jointly-owned by South Dakota Electric (58 MW) and Wyoming Electric (42.4 MW). BHSC is responsible for plant operations.

*Corriedale*

Corriedale serves as the dedicated wind energy supply for Renewable Ready customers in South Dakota and Wyoming. The 52.5 MW wind farm is jointly-owned by South Dakota Electric (32.5 MW) and Wyoming Electric (20 MW). BHSC is responsible for operations of the wind farm.

## (7) ASSET RETIREMENT OBLIGATIONS

We have identified legal retirement obligations related to reclamation of mining sites in the Mining segment, removal of fuel tanks, transformers containing polychlorinated biphenyls, and an evaporation pond at our Electric Utilities, wind turbines at our Electric Utilities and Power Generation segments, retirement of gas pipelines at our Gas Utilities and removal of asbestos at our Electric and Gas Utilities. We periodically review and update estimated costs related to these AROs. The actual cost may vary from estimates because of regulatory requirements, changes in technology and increased costs of labor, materials and equipment.

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

| | December 31, 2019 | Liabilities Incurred | Liabilities Settled | Accretion | Revisions to Prior Estimates | December 31, 2020 |
|---|---|---|---|---|---|---|
| Electric Utilities [a] | $ 9,329 | $ 1,217 | $ — | $ 407 | $ — | $ 10,953 |
| Gas Utilities [b] | 36,085 | 4,782 | (132) | 1,539 | — | 42,274 |
| Power Generation | 4,739 | — | — | 206 | — | 4,945 |
| Mining [c] | 14,052 | — | (185) | 617 | (1,225) | 13,259 |
| Total | 64,205 | $ 5,999 | $ (317) | $ 2,769 | $ (1,225) | $ 71,431 |

| | December 31, 2018 | Liabilities Incurred | Liabilities Settled | Accretion | Revisions to Prior Estimates | December 31, 2019 |
|---|---|---|---|---|---|---|
| Electric Utilities [d] | $ 6,258 | $ — | $ — | $ 385 | $ 2,686 | $ 9,329 |
| Gas Utilities | 34,627 | — | — | 1,458 | — | 36,085 |
| Power Generation [a] | 300 | 3,445 | — | 158 | 836 | 4,739 |
| Mining [c] | 15,615 | — | (380) | 740 | (1,923) | 14,052 |
| Total | $ 56,800 | $ 3,445 | $ (380) | $ 2,741 | $ 1,599 | $ 64,205 |

(a) Liabilities incurred were related to new wind assets.
(b) Liabilities incurred were driven by an increase in gas pipeline miles; which increases our legal liability for retirement of gas pipelines, specifically to purge and cap these lines in accordance with Federal regulations.
(c) The Mining Revisions to Prior Estimates were primarily driven by changes in estimated costs associated with back-filling the pit with overburden removed during the mining process.
(d) The Electric Utilities Revisions to Prior Estimates was primarily driven by an increase in the estimated cost to decommission certain regulated wind farm assets.

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

## (8) LEASES

**Lessee**

We lease from third parties certain office and operation center facilities, communication tower sites, equipment, and materials storage. Our leases have remaining terms ranging from less than 1 year to 35 years, including options to extend that are reasonably certain to be exercised. We have one immaterial finance lease for communication equipment at the WRDC mine.

Most of our leases do not contain a readily determinable discount rate. Therefore, the present value of future lease payments is generally calculated using our applicable subsidiaries' incremental borrowing rate (weighted-average of 4.24% as of December 31, 2020).

Leases with an initial term of 12 months or less are classified as short-term leases and are not recognized on the accompanying Consolidated Balance Sheets.

Lease expense for the year ended December 31 were as follows (in thousands):

| | Income Statement Location | 2020 | 2019 |
|---|---|---|---|
| Operating lease cost | Operations and maintenance | $ 978 | $ 1,456 |

Supplemental balance sheet information related to leases as of December 31 was as follows (in thousands):

| | Balance Sheet Location | 2020 | 2019 |
|---|---|---|---|
| Assets: | | | |
| Operating lease assets | Other assets, non-current | $ 4,188 | $ 4,629 |
| Total lease assets | | $ 4,188 | $ 4,629 |
| Liabilities: | | | |
| Current: | | | |
| Operating leases | Accrued liabilities | $ 736 | $ 1,179 |
| Noncurrent: | | | |
| Operating leases | Other deferred credits and other liabilities | 3,807 | 3,821 |
| Total lease liabilities | | $ 4,543 | $ 5,000 |

Supplemental cash flow information related to leases for the year ended December 31 was as follows (in thousands):

| | 2020 | 2019 |
|---|---|---|
| Cash paid included in the measurement of lease liabilities: | | |
| Operating cash flows from operating leases | $ 1,023 | $ 1,263 |
| Right-of-use assets obtained in exchange for lease obligations: | | |
| Operating leases | $ 161 | $ 2,801 |

Weighted average remaining terms and discount rates related to leases as of December 31 were as follows:

| | 2020 | 2019 |
|---|---|---|
| Weighted average remaining lease term: | | |
| Operating leases | 8 years | 8 years |
| Weighted average discount rate: | | |
| Operating leases | 4.24 % | 4.27 % |

As of December 31, 2020, scheduled maturities of lease liabilities for future years were as follows (in thousands):

| | Operating Leases |
|---|---|
| 2021 | $ 907 |
| 2022 | 804 |
| 2023 | 779 |
| 2024 | 776 |
| 2025 | 529 |
| Thereafter | 1,643 |
| Total lease payments | $ 5,438 |
| Less imputed interest | 895 |
| Present value of lease liabilities | $ 4,543 |

Lessor

We lease to third parties certain generating station ground leases, communication tower sites, and a natural gas pipeline. These leases have remaining terms ranging from less than one year to 34 years.

Lease revenue for the year ended December 31 were as follows (in thousands):

| | Income Statement Location | 2020 | 2019 |
|---|---|---|---|
| Operating lease income | Revenue | $ 2,534 | $ 2,306 |

As of December 31, 2020, scheduled maturities of operating lease payments to be received in future years were as follows (in thousands):

| | Operating Leases |
|---|---|
| 2021 | $ 2,383 |
| 2022 | 2,122 |
| 2023 | 2,130 |
| 2024 | 2,074 |
| 2025 | 2,090 |
| Thereafter | 58,829 |
| Total lease receivables | $ 69,628 |

**(9) DEBT AND CREDIT FACILITIES**

**Short-term debt**

We had the following Notes payable outstanding at the Consolidated Balance Sheets date (in thousands):

| | December 31, 2020 | | December 31, 2019 | |
|---|---|---|---|---|
| | Balance Outstanding | Letters of Credit [(a)] | Balance Outstanding | Letters of Credit [(a)] |
| Revolving Credit Facility | $ — | $ 24,730 | $ — | $ 30,274 |
| CP Program | 234,040 | — | 349,500 | — |
| Total | $ 234,040 | $ 24,730 | $ 349,500 | $ 30,274 |

(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

On July 30, 2018, we amended and restated our corporate Revolving Credit Facility, maintaining total commitments of $750 million and extending the term through July 30, 2023 with two one year extension options (subject to consent from lenders). This facility includes an accordion feature that allows us, with the consent of the administrative agent, the issuing agents and each bank increasing or providing a new commitment, to increase total commitments up to $1.0 billion. Borrowings continue to be available under a base rate or various Eurodollar rate options. The interest costs associated with the letters of credit or borrowings and the commitment fee under the Revolving Credit Facility are determined based upon our Corporate credit rating from S&P, Fitch and Moody's for our senior unsecured long-term debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings and letters of credit were 0.125%, 1.125% and 1.125%, respectively, at December 31, 2020. Based on our credit ratings, a 0.175% commitment fee was charged on the unused amount at December 31, 2020.

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

Our net short-term borrowings (payments) during 2020 were $(115) million. As of December 31, 2020, the weighted average interest rate on short-term borrowings was 0.27%.

Total accumulated deferred financing costs on the Revolving Credit Facility of $6.7 million are being amortized over its estimated useful life and were included in Interest expense on the accompanying Consolidated Statements of Income. See below for additional details.

**Long-term debt**

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

| | Due Date | Interest Rate at December 31, 2020 | Balance Outstanding December 31, 2020 | Balance Outstanding December 31, 2019 |
|---|---|---|---|---|
| Corporate | | | | |
| Senior unsecured notes due 2023 | November 30, 2023 | 4.25% | $ 525,000 | $ 525,000 |
| Senior unsecured notes due 2026 | January 15, 2026 | 3.95% | 300,000 | 300,000 |
| Senior unsecured notes due 2027 | January 15, 2027 | 3.15% | 400,000 | 400,000 |
| Senior unsecured notes, due 2029 | October 15, 2029 | 3.05% | 400,000 | 400,000 |
| Senior unsecured notes, due 2030 | June 15, 2030 | 2.50% | 400,000 | — |
| Senior unsecured notes due 2033 | May 1, 2033 | 4.35% | 400,000 | 400,000 |
| Senior unsecured notes, due 2046 | September 15, 2046 | 4.20% | 300,000 | 300,000 |
| Senior unsecured notes, due 2049 | October 15, 2049 | 3.88% | 300,000 | 300,000 |
| Corporate term loan due 2021 | June 7, 2021 | 2.32% | 1,436 | 7,178 |
| Total Corporate debt | | | 3,026,436 | 2,632,178 |
| Less unamortized debt discount | | | (7,013) | (6,462) |
| Total Corporate debt, net | | | 3,019,423 | 2,625,716 |
| South Dakota Electric | | | | |
| Series 94A Debt, variable rate [(a)] | June 1, 2024 | N/A | — | 2,855 |
| First Mortgage Bonds due 2032 | August 15, 2032 | 7.23% | 75,000 | 75,000 |
| First Mortgage Bonds due 2039 | November 1, 2039 | 6.13% | 180,000 | 180,000 |
| First Mortgage Bonds due 2044 | October 20, 2044 | 4.43% | 85,000 | 85,000 |
| Total South Dakota Electric debt | | | 340,000 | 342,855 |
| Less unamortized debt discount | | | (78) | (82) |
| Total South Dakota Electric debt, net | | | 339,922 | 342,773 |
| Wyoming Electric | | | | |
| Industrial development revenue bonds due 2021 [(a) (b)] | September 1, 2021 | 0.12% | 7,000 | 7,000 |
| Industrial development revenue bonds due 2027 [(a) (b)] | March 1, 2027 | 0.12% | 10,000 | 10,000 |
| First Mortgage Bonds due 2037 | November 20, 2037 | 6.67% | 110,000 | 110,000 |
| First Mortgage Bonds due 2044 | October 20, 2044 | 4.53% | 75,000 | 75,000 |
| Total Wyoming Electric debt | | | 202,000 | 202,000 |
| Less unamortized debt discount | | | — | — |
| Total Wyoming Electric debt, net | | | 202,000 | 202,000 |
| Total long-term debt | | | 3,561,345 | 3,170,489 |
| Less current maturities | | | 8,436 | 5,743 |
| Less unamortized deferred financing costs [(c)] | | | 24,809 | 24,650 |
| Long-term debt, net of current maturities and deferred financing costs | | | $ 3,528,100 | $ 3,140,096 |

(a) Variable interest rate.
(b) A reimbursement agreement is in place with Wells Fargo on behalf of Wyoming Electric for the 2009A bonds of $10 million due March 1, 2027 and the 2009B bonds of $7.0 million due September 1, 2021. In the case of default, we hold the assumption of liability for drawings on Wyoming Electric's Letter of Credit attached to these bonds.
(c) Includes deferred financing costs associated with our Revolving Credit Facility of $1.0 million and $1.7 million as of December 31, 2020 and December 31, 2019, respectively.

Scheduled maturities of long-term debt, excluding amortization of premiums or discounts, for future years are (in thousands):

| | | |
|---|---|---|
| 2021 | $ | 8,436 |
| 2022 | $ | — |
| 2023 | $ | 525,000 |
| 2024 | $ | — |
| 2025 | $ | — |
| Thereafter | $ | 3,035,000 |

Our debt securities contain certain restrictive financial covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2020. See below for additional information.

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

Amortization of Deferred Financing Costs

Our deferred financing costs and associated amortization expense included in Interest expense on the accompanying Consolidated Statements of Income were as follows (in thousands):

| Deferred Financing Costs Remaining at December 31, 2020 | Amortization Expense for the years ended December 31, 2020 | 2019 | 2018 |
|---|---|---|---|
| $ 24,809 | $ 3,272 | $ 3,242 | $ 2,829 |

Debt Transactions

On June 17, 2020, we completed a public debt offering which consisted of $400 million of 2.50% 10-year senior unsecured notes due June 15, 2030. The proceeds were used to repay short-term debt and for working capital and general corporate purposes.

On March 24, 2020, South Dakota Electric paid off its $2.9 million, Series 94A variable rate notes due June 1, 2024. These notes were tendered by the sole investor on March 17, 2020.

On October 3, 2019, we completed a public debt offering of $700 million principal amount in senior unsecured notes. The debt offering consisted of $400 million of 3.05% 10-year senior notes due October 15, 2029 and $300 million of 3.875% 30-year senior notes due October 15, 2049 (together the “Notes”). The proceeds of the Notes were used for the following:

- Repay the $400 million Corporate term loan under the Amended and Restated Credit Agreement due June 17, 2021;
- Retire the $200 million 5.875% senior notes due July 15, 2020; and
- Repay a portion of short-term debt.

On June 17, 2019, we amended our Corporate term loan due July 30, 2020. This amendment increased total commitments to $400 million from $300 million, extended the term through June 17, 2021, and had substantially similar terms and covenants as the amended and restated Revolving Credit Facility. The net proceeds from the increase in total commitments were used to pay down short-term debt. Proceeds from the October 3, 2019 public debt offering were used to repay this term loan.

**Debt Covenants**

Revolving Credit Facility

Under our Revolving Credit Facility and term loan agreements we are required to maintain a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.65 to 1.00. Our Consolidated Indebtedness to Capitalization Ratio is calculated by dividing (i) Consolidated Indebtedness, which includes letters of credit and certain guarantees issued by (ii) Capital, which includes Consolidated Indebtedness plus Net Worth, which excludes noncontrolling interest in subsidiaries. Subject to applicable cure periods, a violation of any of these covenants would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding.

We were in compliance with our covenants at December 31, 2020 as shown below:

| | As of December 31, 2020 | Covenant Requirement | |
|---|---|---|---|
| Consolidated Indebtedness to Capitalization Ratio | 59.9% | Less than | 65% |

Wyoming Electric

Covenants within Wyoming Electric's financing agreements require Wyoming Electric to maintain a debt to capitalization ratio of no more than 0.60 to 1.00. As of December 31, 2020, we were in compliance with these covenants.

**Dividend Restrictions**

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

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our shareholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries. The following restrictions on distributions from our subsidiaries existed at December 31, 2020:

- Our utilities are generally limited to the amount of dividends allowed to be paid to our utility holding company under the Federal Power Act and settlement agreements with state regulatory jurisdictions. As of December 31, 2020, the restricted net assets at our Electric and Gas Utilities were approximately $155 million.

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

**(10) STOCKHOLDERS' EQUITY**

**February 2020 Equity Issuance**

On February 27, 2020, we issued 1.2 million shares of common stock to a single investor through an underwritten registered transaction at a price of $81.77 per share for proceeds of $99 million, net of $1.0 million of issuance costs. The shares of common stock were offered pursuant to our shelf registration statement filed with the SEC.

**At-the-Market Equity Offering Program**

On August 3, 2020, we filed a shelf registration and DRSPP with the SEC. In conjunction with these shelf filings, we renewed the ATM. The renewed ATM program, which allows us to sell shares of our common stock, is the same as the prior program other than the aggregate value increased from $300 million to $400 million and a forward sales option was incorporated. This forward sales option allows us to sell our shares through the ATM program at the current trading price without actually issuing any shares to satisfy the sale until a future date. Under the ATM, shares may be offered from time to time pursuant to a sales agreement dated August 3, 2020. Shares of common stock are offered pursuant to our shelf registration statement filed with the SEC.

We did not issue any common shares under the ATM during the twelve months ended December 31, 2020. During the twelve months ended December 31, 2019, we issued a total of 1,328,332 shares of common stock under the ATM for $99 million, net of $1.2 million in issuance costs. We did not issue any common shares under the ATM during the twelve months ended December 31, 2018.

**Shareholder Dividend Reinvestment and Stock Purchase Plan**

We have a DRSPP under which shareholders may purchase additional shares of common stock through dividend reinvestment and/or optional cash payments at 100% of the recent average market price. We have the option of issuing new shares or purchasing the shares on the open market. We issued new shares until March 1, 2018, after which we began purchasing shares on the open market. At December 31, 2020, there were 163,962 shares of unissued stock available for future offering under the DRSPP.

**Preferred Stock**

Our articles of incorporation authorize the issuance of 25 million shares of preferred stock of which we had no shares of preferred stock outstanding.

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## (11) RISK MANAGEMENT AND DERIVATIVES

**Market and Credit Risk Disclosures**

Our activities in the regulated and non-regulated energy sectors 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. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures. Valuation methodologies for our derivatives are detailed within Note 1.

Market Risk

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

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

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

Credit Risk

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

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

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer's current creditworthiness, as determined by review of their current credit information. We maintain a provision for estimated credit losses based upon historical experience, changes in current market conditions, expected losses and any specific customer collection issue that is identified. Our credit exposure at December 31, 2020 was concentrated primarily among retail utility customers, investment grade companies, cooperative utilities and federal agencies.

We continue to monitor COVID-19 impacts and changes to customer load, consistency in customer payments, requests for deferred or discounted payments, and requests for changes to credit limits to quantify estimated future financial impacts to the allowance for credit losses. During the year ended December 31, 2020, the potential economic impact of the COVID-19 pandemic was considered in forward looking projections related to write-off and recovery rates, and resulted in increases to the allowance for credit losses and bad debt expense of $3.3 million. See Note 1 for further information.

**Derivatives and Hedging Activity**

Our derivative and hedging activities included in the accompanying Consolidated Balance Sheets, Consolidated Statements of Income and Consolidated Statements of Comprehensive Income (Loss) are detailed below and within Note 12.

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

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

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

We buy, sell and deliver natural gas at competitive prices by managing commodity price risk. As a result of these activities, this area of our business is exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks using over-the-counter and exchange traded options and swaps with counterparties in anticipation of forecasted purchases and sales during time frames ranging from January 2021 through May 2022. A portion of our over-the-counter swaps have been designated as cash flow hedges to mitigate the commodity price risk associated with deliveries under fixed price forward contracts to deliver gas to our Choice Gas Program customers. The gain or loss on these designated derivatives is reported in AOCI in the accompanying Consolidated Balance Sheets and reclassified into earnings in the same period that the underlying hedged item is recognized in earnings. Effectiveness of our hedging position is evaluated at least quarterly.

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

| | December 31, 2020 | | December 31, 2019 | |
|---|---|---|---|---|
| | Notional (MMBtus) | Maximum Term (months) [(a)] | Notional (MMBtus) | Maximum Term (months) [(a)] |
| Natural gas futures purchased | 620,000 | 3 | 1,450,000 | 12 |
| Natural gas options purchased, net | 3,160,000 | 3 | 3,240,000 | 3 |
| Natural gas basis swaps purchased | 900,000 | 3 | 1,290,000 | 12 |
| Natural gas over-the-counter swaps, net [(b)] | 3,850,000 | 17 | 4,600,000 | 24 |
| Natural gas physical commitments, net [(c)] | 17,513,061 | 22 | 13,548,235 | 12 |
| Electric wholesale contracts [(c)] | 219,000 | 12 | — | 0 |

(a) Term reflects the maximum forward period hedged.
(b) As of December 31, 2020, 914,600 of natural gas over-the-counter swaps purchased were designated as cash flow hedges.
(c) Volumes exclude derivative contracts that qualify for the normal purchase, normal sales exception permitted by GAAP.

We have certain derivative contracts which contain credit provisions. These credit provisions may require the Company to post collateral when credit exposure to the Company is in excess of a negotiated line of unsecured credit. At December 31, 2020, the Company posted $1.5 million related to such provisions, which is included in Other current assets on the Consolidated Balance Sheets.

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Derivatives by Balance Sheet Classification

As required by accounting standards for derivatives and hedges, fair values within the following tables are presented on a gross basis aside from the netting of asset and liability positions. Netting of positions is permitted in accordance with accounting standards for offsetting and under terms of our master netting agreements that allow us to settle positive and negative positions.

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

| | Balance Sheet Location | 2020 | 2019 |
|---|---|---|---|
| Derivatives designated as hedges: | | | |
| Asset derivative instruments: | | | |
| Current commodity derivatives | Derivative assets - current | $ 181 | $ 1 |
| Noncurrent commodity derivatives | Other assets, non-current | 43 | 3 |
| Liability derivative instruments: | | | |
| Current commodity derivatives | Derivative liabilities - current | (108) | (490) |
| Noncurrent commodity derivatives | Other deferred credits and other liabilities | — | (29) |
| Total derivatives designated as hedges | | $ 116 | $ (515) |
| | | | |
| Derivatives not designated as hedges: | | | |
| Asset derivative instruments: | | | |
| Current commodity derivatives | Derivative assets - current | $ 1,667 | $ 341 |
| Noncurrent commodity derivatives | Other assets, non-current | 151 | 2 |
| Liability derivative instruments: | | | |
| Current commodity derivatives | Derivative liabilities - current | (1,936) | (1,764) |
| Noncurrent commodity derivatives | Other deferred credits and other liabilities | — | (63) |
| Total derivatives not designated as hedges | | $ (118) | $ (1,484) |

Derivatives Designated as Hedge Instruments

The impact of cash flow hedges on our Consolidated Statements of Income is presented below for the years ended December 31, 2020, 2019 and 2018. 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 | 2020 | 2019 | 2018 | Income Statement Location | 2020 | 2019 | 2018 |
|---|---|---|---|---|---|---|---|
| | Amount of Gain/(Loss) Recognized in OCI | | | | Amount of Gain/(Loss) Reclassified from AOCI into Income | | |
| | (in thousands) | | | | (in thousands) | | |
| Interest rate swaps | $ 2,851 | $ 2,851 | $ 2,851 | Interest expense | $ (2,851) | $ (2,851) | $ (2,851) |
| Commodity derivatives | 540 | (965) | 1,113 | Fuel, purchased power and cost of natural gas sold | (601) | 417 | (130) |
| Total | $ 3,391 | $ 1,886 | $ 3,964 | | $ (3,452) | $ (2,434) | $ (2,981) |

As of December 31, 2020, $2.8 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.

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Derivatives Not Designated as Hedge Instruments

The following table summarizes the impacts of derivative instruments not designated as hedge instruments on our Consolidated Statements of Income for the years ended December 31, 2020, 2019 and 2018. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

| Derivatives Not Designated as Hedging Instruments | Income Statement Location | 2020 | 2019 | 2018 |
|---|---|---|---|---|
| | | Amount of Gain/(Loss) on Derivatives Recognized in Income | | |
| | | (in thousands) | | |
| Commodity derivatives - Electric | Fuel, purchased power and cost of natural gas sold | $ 144 | $ — | $ — |
| Commodity derivatives - Natural Gas | Fuel, purchased power and cost of natural gas sold | 1,640 | (1,100) | 1,101 |
| | | $ 1,784 | $ (1,100) | $ 1,101 |

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 assets or Regulatory liability accounts related to these financial instruments in our Gas Utilities were $2.2 million and $3.3 million at December 31, 2020 and 2019, respectively. For our Electric Utilities, the unrealized gains and losses arising from these derivatives are recognized in the Consolidated Statements of Income.

## (12) FAIR VALUE MEASUREMENTS

Recurring Fair Value Measurements

*Derivatives*

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

| | As of December 31, 2020 | | | | |
|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Cash Collateral and Counterparty Netting (a) | Total |
| | (in thousands) | | | | |
| Assets: | | | | | |
| Commodity derivatives - Gas Utilities | $ — | $ 2,504 | $ — | $ (1,527) | $ 977 |
| Commodity derivatives - Electric Utilities | — | 1,065 | — | — | 1,065 |
| Total | $ — | $ 3,569 | $ — | $ (1,527) | $ 2,042 |
| Liabilities: | | | | | |
| Commodity derivatives - Gas Utilities | $ — | $ 2,675 | $ — | $ (1,552) | $ 1,123 |
| Commodity derivatives - Electric Utilities | | $ 921 | | $ — | $ 921 |
| Total | $ — | $ 3,596 | $ — | $ (1,552) | $ 2,044 |

(a) As of December 31, 2020, $1.5 million of our commodity derivative gross assets and $1.6 million of our commodity derivative gross liabilities, as well as related gross collateral amounts, were subject to master netting agreements.

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| | As of December 31, 2019 | | | | |
|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Cash Collateral and Counterparty Netting (a) | Total |
| Assets: | | | | | |
| Commodity derivatives - Gas Utilities | $ — | 1,433 | $ — | $ (1,085) | $ 348 |
| Total | $ — | $ 1,433 | $ — | $ (1,085) | $ 348 |
| | | | | | |
| Liabilities: | | | | | |
| Commodity derivatives - Gas Utilities | $ — | $ 5,254 | $ — | $ (2,909) | $ 2,345 |
| Total | $ — | $ 5,254 | $ — | $ (2,909) | $ 2,345 |

(a) As of December 31, 2019, $1.1 million of our commodity derivative assets and $2.9 million of our commodity derivative liabilities, as well as related gross collateral amounts, were subject to master netting agreements.

*Pension and Postretirement Plan Assets*

A discussion of the fair value of our Pension and Postretirement Plan assets is included in Note 15.

Nonrecurring Fair Value Measurement

A discussion of the fair value of our investment in equity securities of a privately held oil and gas company, a Level 3 asset, is included in Note 1.

Other Fair Value Measurements

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

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

| | 2020 | | 2019 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Long-term debt, including current maturities (a) | $ 3,536,536 | $ 4,208,167 | $ 3,145,839 | $ 3,479,367 |

(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.

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## (13) OTHER COMPREHENSIVE INCOME

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

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

| | Location on the Consolidated Statements of Income | Amount Reclassified from AOCI December 31, 2020 | December 31, 2019 |
|---|---|---|---|
| Gains and (losses) on cash flow hedges: | | | |
| Interest rate swaps | Interest expense | $ (2,851) | $ (2,851) |
| Commodity contracts | Fuel, purchased power and cost of natural gas sold | (601) | 417 |
| | | (3,452) | (2,434) |
| Income tax | Income tax benefit (expense) | 383 | 611 |
| Total reclassification adjustments related to cash flow hedges, net of tax | | $ (3,069) | $ (1,823) |
| | | | |
| Amortization of components of defined benefit plans: | | | |
| Prior service cost | Operations and maintenance | $ 103 | $ 77 |
| | | | |
| Actuarial gain (loss) | Operations and maintenance | (2,387) | (745) |
| | | (2,284) | (668) |
| Income tax | Income tax benefit (expense) | 935 | (453) |
| Total reclassification adjustments related to defined benefit plans, net of tax | | $ (1,349) | $ (1,121) |
| | | | |
| Total reclassifications | | $ (4,418) | $ (2,944) |

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

| | Derivatives Designated as Cash Flow Hedges | | | |
|---|---|---|---|---|
| | Interest Rate Swaps | Commodity Derivatives | Employee Benefit Plans | Total |
| As of December 31, 2019 | $ (15,122) | $ (456) | $ (15,077) | $ (30,655) |
| Other comprehensive income (loss) before reclassifications | — | (47) | (1,062) | (1,109) |
| Amounts reclassified from AOCI | 2,564 | 505 | 1,349 | 4,418 |
| As of December 31, 2020 | $ (12,558) | $ 2 | $ (14,790) | $ (27,346) |

| | Derivatives Designated as Cash Flow Hedges | | | |
|---|---|---|---|---|
| | Interest Rate Swaps | Commodity Derivatives | Employee Benefit Plans | Total |
| As of December 31, 2018 | $ (17,307) | $ 328 | $ (9,937) | $ (26,916) |
| Other comprehensive income (loss) before reclassifications | — | (422) | (6,261) | (6,683) |
| Amounts reclassified from AOCI | 2,185 | (362) | 1,121 | 2,944 |
| As of December 31, 2019 | $ (15,122) | $ (456) | $ (15,077) | $ (30,655) |

**(14) VARIABLE INTEREST ENTITY**

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

The accounting for a partial sale of a subsidiary in which control is maintained and the subsidiary continues to be consolidated, is specified under ASC 810, *Consolidation*. The partial sale is required to be recorded as an equity transaction with no resulting gain or loss on the sale. GAAP requires that noncontrolling interests in subsidiaries and affiliates be reported in the equity section of a company's balance sheet.

Net income available for common stock for the years ended December 31, 2020, 2019 and 2018 was reduced by $15 million, $14 million, and $14 million, respectively, attributable to this noncontrolling interest. The net income allocable to the noncontrolling interest holder is based on ownership interest with the exception of certain agreed upon adjustments. Distributions of net income attributable to this noncontrolling interest are due within 30 days following the end of a quarter, but may be withheld as necessary by Black Hills Electric Generation.

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

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We have recorded the following assets and liabilities on our consolidated balance sheets related to the VIE described above as of December 31 (in thousands):

| | 2020 | 2019 |
|---|---|---|
| Assets: | | |
| Current assets | $ 13,604 | $ 13,350 |
| Property, plant and equipment of variable interest entities, net | $ 190,637 | $ 193,046 |
| | | |
| Liabilities: | | |
| Current liabilities | $ 5,318 | $ 6,013 |

## (15) EMPLOYEE BENEFIT PLANS

### Defined Contribution Plans

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

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

### Defined Benefit Pension Plan

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

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

The expected rate of return on the Pension Plan assets is determined by reviewing the historical and expected returns of both equity and fixed income markets, taking into account asset allocation, the correlation between asset class returns, and the mix of active and passive investments. The Pension Plan utilizes a dynamic asset allocation where the target range to return-seeking and liability-hedging assets is determined based on the funded status of the Plan. As of December 31, 2020, the expected rate of return on pension plan assets was based on the targeted asset allocation range of 28% to 36% return-seeking assets and 64% to 72% liability-hedging assets.

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

Plan Assets

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

| | 2020 | 2019 |
|---|---|---|
| Equity | 21% | 20% |
| Real estate | 3 | 3 |
| Fixed income | 69 | 71 |
| Cash | 3 | 1 |
| Hedge funds | 4 | 5 |
| Total | 100% | 100% |

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**Supplemental Non-qualified Defined Benefit Plans**

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

**Non-pension Defined Benefit Postretirement Healthcare Plan**

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

We fund the Healthcare Plan on a cash basis as benefits are paid. The Healthcare Plan provides for partial pre-funding via VEBA trusts. Assets related to this pre-funding are held in trust and are for the benefit of the union and non-union employees located in the states of Arkansas, Iowa and Kansas. We do not pre-fund the Healthcare Plan for those employees outside Arkansas, Iowa and Kansas.

**Plan Contributions**

Contributions to the Pension Plan are cash contributions made directly to the Master Trust. Healthcare and Supplemental Plan contributions are made in the form of benefit payments. Healthcare benefits include company and participant paid premiums. Contributions for the years ended December 31 were as follows (in thousands):

| | 2020 | 2019 |
|---|---|---|
| Defined Contribution Plan | | |
| Company retirement contributions | $ 10,455 | $ 9,714 |
| Company matching contributions | $ 15,240 | $ 14,558 |

| | 2020 | 2019 |
|---|---|---|
| Defined Benefit Plans | | |
| Defined Benefit Pension Plan | $ 12,700 | $ 12,700 |
| Non-Pension Defined Benefit Postretirement Healthcare Plan | $ 6,058 | $ 7,033 |
| Supplemental Non-Qualified Defined Benefit Plans | $ 2,674 | $ 2,344 |

We do not have required 2021 contributions and currently do not expect to contribute to our Pension Plan.

**Fair Value Measurements**

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

| Pension Plan | December 31, 2020 | | | | | |
|---|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total Investments Measured at Fair Value | NAV (a) | Total Investments |
| Common Collective Trust - Cash and Cash Equivalents | $ — | $ 16,810 | $ — | $ 16,810 | $ — | $ 16,810 |
| Common Collective Trust - Equity | — | 100,311 | — | 100,311 | — | 100,311 |
| Common Collective Trust - Fixed Income | — | 324,845 | — | 324,845 | — | 324,845 |
| Common Collective Trust - Real Estate | — | — | — | — | 14,301 | 14,301 |
| Hedge Funds | — | — | — | — | 17,454 | 17,454 |
| Total investments measured at fair value | $ — | $ 441,966 | $ — | $ 441,966 | $ 31,755 | $ 473,721 |

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| Pension Plan | December 31, 2019 | | | | | |
|---|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total Investments Measured at Fair Value | NAV (a) | Total Investments |
| AXA Equitable General Fixed Income | $ — | $ 60 | $ — | $ 60 | $ — | $ 60 |
| Common Collective Trust - Cash and Cash Equivalents | — | 7,054 | — | 7,054 | — | 7,054 |
| Common Collective Trust - Equity | — | 87,106 | — | 87,106 | — | 87,106 |
| Common Collective Trust - Fixed Income | — | 306,275 | — | 306,275 | — | 306,275 |
| Common Collective Trust - Real Estate | — | — | — | — | 14,239 | 14,239 |
| Hedge Funds | — | — | — | — | 19,550 | 19,550 |
| Total investments measured at fair value | $ — | $ 400,495 | $ — | $ 400,495 | $ 33,789 | $ 434,284 |

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

| Non-pension Defined Benefit Postretirement Healthcare Plan | December 31, 2020 | | | | |
|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total Investments Measured at Fair Value | Total Investments |
| Cash and Cash Equivalents | $ 8,165 | $ — | $ — | $ 8,165 | $ 8,165 |
| Total investments measured at fair value | $ 8,165 | $ — | $ — | $ 8,165 | $ 8,165 |

| Non-pension Defined Benefit Postretirement Healthcare Plan | December 31, 2019 | | | | |
|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total Investments Measured at Fair Value | Total Investments |
| Cash and Cash Equivalents | $ 8,305 | $ — | $ — | $ 8,305 | $ 8,305 |
| Total investments measured at fair value | $ 8,305 | $ — | $ — | $ 8,305 | $ 8,305 |

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

Pension Plan

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

*Common Collective Trust-Real Estate Funds*: These funds are valued based on various factors of the underlying real estate properties, including market rent, market rent growth, occupancy levels, etc. As part of the trustee's valuation process, properties are externally appraised generally on an annual basis. The appraisals are conducted by reputable independent appraisal firms and signed by appraisers that are members of the Appraisal Institute, with professional designation of Member, Appraisal Institute. All external appraisals are performed in accordance with the Uniform Standards of Professional Appraisal Practices. We receive monthly statements from the trustee, along with the annual schedule of investments and rely on these reports for pricing the units of the fund. Some of the funds without participant withdrawal limitations are categorized as Level 2.

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

*Common Collective Trust-Real Estate Fund*: This is the same fund as above except that certain of the funds' assets contain participant withdrawal policies with restrictions on redemption and are therefore not included in the fair value hierarchy.

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

Non-pension Defined Benefit Postretirement Healthcare Plan

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

**Other Plan Information**

The following tables provide a reconciliation of the employee benefit plan obligations and fair value of employee benefit plan assets, amounts recognized in the Consolidated Balance Sheets, accumulated benefit obligation, and reconciliation of components of the net periodic expense and elements of AOCI (in thousands):

Employee Benefit Plan Obligations

| | Defined Benefit Pension Plan | | Supplemental Non-qualified Defined Benefit Plans | | Non-pension Defined Benefit Postretirement Healthcare Plan | |
|---|---|---|---|---|---|---|
| As of December 31, | 2020 | 2019 | 2020 | 2019 | 2020 | 2019 |
| Change in benefit obligation: | | | | | | |
| Projected benefit obligation at beginning of year | $ 485,376 | $ 445,381 | $ 54,088 | $ 43,010 | $ 65,277 | $ 60,817 |
| Service cost [(a)] | 5,411 | 5,383 | 1,579 | 4,995 | 2,056 | 1,815 |
| Interest cost | 13,426 | 17,374 | 1,099 | 1,295 | 1,649 | 2,247 |
| Actuarial (gain) loss | 47,064 | 56,384 | 962 | 7,132 | 5,804 | 5,976 |
| Benefits paid | (37,269) | (39,146) | (2,674) | (2,344) | (6,058) | (7,033) |
| Plan participants' contributions | — | — | — | — | 1,510 | 1,455 |
| Projected benefit obligation at end of year | $ 514,008 | $ 485,376 | $ 55,054 | $ 54,088 | $ 70,238 | $ 65,277 |

(a) For the year ended December 31, 2020, Service Cost for the Supplemental Non-qualified Defined Benefit Plans includes a $1.4 million correction of a prior year overstatement of Projected benefit obligation. Due to the immaterial nature of this correction, the prior year information was not revised.

Fair Value Employee Benefit Plan Assets

| | Defined Benefit Pension Plan | | Supplemental Non-qualified Defined Benefit Plans | | Non-pension Defined Benefit Postretirement Healthcare Plan [(a)] | |
|---|---|---|---|---|---|---|
| As of December 31, | 2020 | 2019 | 2020 | 2019 | 2020 | 2019 |
| Change in fair value of plan assets: | | | | | | |
| Beginning fair value of plan assets | $ 434,284 | $ 390,796 | $ — | $ — | $ 8,305 | $ 8,162 |
| Investment income (loss) | 64,006 | 69,934 | — | — | 33 | 260 |
| Employer contributions | 12,700 | 12,700 | 2,674 | 2,344 | 4,374 | 5,461 |
| Retiree contributions | — | — | — | — | 1,511 | 1,455 |
| Benefits paid | (37,269) | (39,146) | (2,674) | (2,344) | (6,058) | (7,033) |
| Ending fair value of plan assets | $ 473,721 | $ 434,284 | $ — | $ — | $ 8,165 | $ 8,305 |

(a) Assets of VEBA trusts.

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In 2012, we froze our Pension Plan and closed it to new participants. Since then, we have implemented various de-risking strategies including lump sum buyouts, the purchase of annuities and the reduction of return-seeking assets over time to a more liability-hedged portfolio. As a result, recent capital markets volatility driven by the COVID-19 pandemic did not materially affect our unfunded status.

Amounts Recognized in the Consolidated Balance Sheets

| | Defined Benefit Pension Plan | | Supplemental Non-qualified Defined Benefit Plans | | Non-pension Defined Benefit Postretirement Healthcare Plan | |
|---|---|---|---|---|---|---|
| As of December 31, | 2020 | 2019 | 2020 | 2019 | 2020 | 2019 |
| Regulatory assets | $ 86,677 | $ 88,471 | $ — | $ — | $ 16,102 | $ 11,670 |
| Current liabilities | $ — | $ — | $ 1,927 | $ 1,420 | $ 4,931 | $ 4,802 |
| Non-current liabilities | $ 40,287 | $ 51,093 | $ 53,127 | $ 51,243 | $ 57,142 | $ 52,136 |
| Regulatory liabilities | $ 3,607 | $ 3,524 | $ — | $ — | $ 2,140 | $ 4,088 |

Accumulated Benefit Obligation

| | Defined Benefit Pension Plan | | Supplemental Non-qualified Defined Benefit Plans | | Non-pension Defined Benefit Postretirement Healthcare Plan | |
|---|---|---|---|---|---|---|
| As of December 31, | 2020 | 2019 | 2020 | 2019 | 2020 | 2019 |
| Accumulated Benefit Obligation | $ 498,815 | $ 470,615 | $ 54,779 | $ 49,241 | $ 70,238 | $ 65,277 |

Components of Net Periodic Expense

| | Defined Benefit Pension Plan | | | Supplemental Non-qualified Defined Benefit Plans | | | Non-pension Defined Benefit Postretirement Healthcare Plan | | |
|---|---|---|---|---|---|---|---|---|---|
| For the years ended December 31, | 2020 | 2019 | 2018 | 2020 | 2019 | 2018 | 2020 | 2019 | 2018 |
| Service cost [(a)] | $ 5,411 | $ 5,383 | $ 6,834 | $ 1,579 | $ 4,995 | $ 1,764 | $ 2,056 | $ 1,815 | $ 2,291 |
| Interest cost | 13,426 | 17,374 | 15,470 | 1,099 | 1,295 | 1,170 | 1,649 | 2,247 | 2,085 |
| Expected return on assets | (22,591) | (24,401) | (24,741) | — | — | — | (182) | (230) | (315) |
| Net amortization of prior service cost | — | 26 | 58 | 2 | 2 | 2 | (546) | (398) | (398) |
| Recognized net actuarial loss (gain) | 8,372 | 3,763 | 8,632 | 1,702 | 535 | 1,000 | 20 | — | 216 |
| Net periodic expense | $ 4,618 | $ 2,145 | $ 6,253 | $ 4,382 | $ 6,827 | $ 3,936 | $ 2,997 | $ 3,434 | $ 3,879 |

(a) For the year ended December 31, 2020, Service Cost for the Supplemental Non-qualified Defined Benefit Plans includes a $1.4 million correction of a prior year overstatement of Projected benefit obligation. Due to the immaterial nature of this correction, the prior year information was not revised.

For the years ended December 31, 2020, 2019 and 2018, Service costs were recorded in Operations and maintenance expense while non service costs were recorded in Other expense on the Consolidated Statements of Income.

*Change in Accounting Principle - Pension Accounting Asset Method*

Effective January 1, 2020, the Company changed its method of accounting for net periodic benefit cost. Prior to the change, the Company used a calculated value for determining market-related value of plan assets which amortized the effects of gains and losses over a five-year period. Effective with the accounting change, the Company used a calculated value for the return-seeking assets (equities) in the portfolio and fair value for the liability-hedging assets (fixed income). The Company considers the fair value method for determining market-related value of liability-hedging assets to be a preferable method of accounting because asset-related gains and losses are subject to amortization into pension cost immediately. Additionally, the fair value for liability-hedging assets allows for the impact of gains and losses on this portion of the asset portfolio to be reflected in tandem with changes in the liability which is linked to changes in the discount rate assumption for re-measurement.

We evaluated the effect of this change in accounting method and deemed it immaterial to the historical and current financial statements and therefore did not account for the change retrospectively. Accordingly, the Company calculated the cumulative difference using a calculated value versus fair value to determine market-related value for liability-hedging assets of the portfolio. The cumulative effect of this change, as of January 1, 2020, resulted in a decrease to prior service costs, as recorded in Other income (expense), net, of $0.6 million, an increase in Income tax expense of $0.2 million and an increase to Net income of $0.4 million within the accompanying Consolidated Statements of Income for the year ended December 31, 2020.

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AOCI Amounts (After-Tax)

| | Defined Benefit Pension Plan | | Supplemental Non-qualified Defined Benefit Plans | | Non-pension Defined Benefit Postretirement Healthcare Plan | |
|---|---|---|---|---|---|---|
| As of December 31, | 2020 | 2019 | 2020 | 2019 | 2020 | 2019 |
| Net (gain) loss | $ 5,511 | $ 5,322 | $ 9,323 | $ 9,893 | $ 100 | $ 90 |
| Prior service cost (gain) | — | — | — | 2 | (144) | (230) |
| Total amounts included in AOCI, after-tax not yet recognized as components of net periodic expense | $ 5,511 | $ 5,322 | $ 9,323 | $ 9,895 | $ (44) | $ (140) |

**Assumptions**

| | Defined Benefit Pension Plan | | | Supplemental Non-qualified Defined Benefit Plans | | | Non-pension Defined Benefit Postretirement Healthcare Plan | | |
|---|---|---|---|---|---|---|---|---|---|
| Weighted-average assumptions used to determine benefit obligations: | 2020 | 2019 | 2018 | 2020 | 2019 | 2018 | 2020 | 2019 | 2018 |
| Discount rate | 2.56 % | 3.27 % | 4.40 % | 2.41 % | 3.14 % | 4.34 % | 2.41 % | 3.15 % | 4.28 % |
| Rate of increase in compensation levels | 3.34 % | 3.49 % | 3.52 % | 5.00 % | 5.00 % | 5.00 % | N/A | N/A | N/A |

| | Defined Benefit Pension Plan | | | Supplemental Non-qualified Defined Benefit Plans | | | Non-pension Defined Benefit Postretirement Healthcare Plan | | |
|---|---|---|---|---|---|---|---|---|---|
| Weighted-average assumptions used to determine net periodic benefit cost for plan year: | 2020 | 2019 | 2018 | 2020 | 2019 | 2018 | 2020 | 2019 | 2018 |
| Discount rate [(a)] | 3.27 % | 4.40 % | 3.71 % | 3.14 % | 4.34 % | 3.67 % | 3.15 % | 4.28 % | 3.60 % |
| Expected long-term rate of return on assets [(b)] | 5.25 % | 6.00 % | 6.25 % | N/A | N/A | N/A | 2.35 % | 3.00 % | 3.93 % |
| Rate of increase in compensation levels | 3.49 % | 3.52 % | 3.43 % | 5.00 % | 5.00 % | 5.00 % | N/A | N/A | N/A |

(a) The estimated discount rate for the Defined Benefit Pension Plan is 2.56% for the calculation of the 2021 net periodic pension costs.
(b) The expected rate of return on plan assets is 4.50% for the calculation of the 2021 net periodic pension cost.

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

| | 2020 | 2019 |
|---|---|---|
| **Trend Rate - Medical** | | |
| Pre-65 for next year - All Plans | 6.10% | 6.40% |
| Pre-65 Ultimate trend rate - Black Hills Corp | 4.50% | 4.50% |
| Trend Year | 2027 | 2027 |
| | | |
| Post-65 for next year - All Plans | 4.92% | 4.92% |
| Post-65 Ultimate trend rate - Black Hills Corp | 4.50% | 4.50% |
| Trend Year | 2029 | 2028 |

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

| | Defined Benefit Pension Plan | Supplemental Non-qualified Defined Benefit Plans | Non-pension Defined Benefit Postretirement Healthcare Plan |
|---|---|---|---|
| 2021 | $ 25,842 | $ 1,927 | $ 6,108 |
| 2022 | $ 26,658 | $ 1,968 | $ 5,965 |
| 2023 | $ 27,581 | $ 2,033 | $ 5,725 |
| 2024 | $ 28,284 | $ 2,231 | $ 5,532 |
| 2025 | $ 29,062 | $ 2,690 | $ 5,244 |
| 2026-2030 | $ 144,273 | $ 13,117 | $ 22,872 |

**(16) SHARE-BASED COMPENSATION PLANS**

Our 2015 Omnibus Incentive Plan allows for the granting of stock, restricted stock, restricted stock units, stock options, performance shares and performance share units. We had 561,073 shares available to grant at December 31, 2020.

Compensation expense is determined using the grant date fair value estimated in accordance with the provisions of accounting standards for stock compensation and is recognized over the vesting periods of the individual awards. As of December 31, 2020, total unrecognized compensation expense related to non-vested stock awards was approximately $12 million and is expected to be recognized over a weighted-average period of 2 years. Stock-based compensation expense, which is included in Operations and maintenance on the accompanying Consolidated Statements of Income, was as follows for the years ended December 31 (in thousands):

| | 2020 | 2019 | 2018 |
|---|---|---|---|
| Stock-based compensation expense | $ 5,373 | $ 12,095 | $ 12,390 |

Stock Options

The Company has not issued any stock options since 2014 and has 5,000 stock options outstanding at December 31, 2020. The amount of stock options granted and related exercise activity are not material to the Company’s consolidated financial statements.

Restricted Stock

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

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

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A summary of the status of the restricted stock and restricted stock units at December 31, 2020, was as follows:

| | Restricted Stock | Weighted-Average Grant Date Fair Value |
|---|---|---|
| | (in thousands) | |
| Balance at January 1, 2020 | 192 | $ 65.66 |
| Granted | 116 | 69.49 |
| Vested | (90) | 63.30 |
| Forfeited | (22) | 65.30 |
| Balance at December 31, 2020 | 196 | $ 69.05 |

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

| | Weighted-Average Grant Date Fair Value | Total Fair Value of Shares Vested |
|---|---|---|
| | | (in thousands) |
| 2020 | $ 69.49 | $ 6,722 |
| 2019 | $ 73.66 | $ 8,438 |
| 2018 | $ 57.31 | $ 6,776 |

As of December 31, 2020, there was $10.3 million of unrecognized compensation expense related to non-vested restricted stock that is expected to be recognized over a weighted-average period of 2.2 years.

Performance Share Plan

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

The performance awards are paid 50% in cash and 50% in common stock. The cash portion accrued is classified as a liability and the stock portion is classified as equity. In the event of a change-in-control, performance awards are paid 100% in cash. If it is determined that a change-in-control is probable, the equity portion of $2.7 million at December 31, 2020 would be reclassified as a liability.

Outstanding performance periods at December 31, 2020 were as follows (shares in thousands):

| | | | Possible Payout Range of Target | |
|---|---|---|---|---|
| Grant Date | Performance Period | Target Grant of Shares | Minimum | Maximum |
| January 1, 2020 | January 1, 2020 - December 31, 2022 | 36 | 0% | 200% |
| January 1, 2019 | January 1, 2019 - December 31, 2021 | 36 | 0% | 200% |
| January 1, 2018 | January 1, 2018 - December 31, 2020 | 49 | 0% | 200% |

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A summary of the status of the Performance Share Plan at December 31, 2020 was as follows:

| | Equity Portion | | Liability Portion | |
|---|---|---|---|---|
| | Shares | Weighted-Average Grant Date Fair Value (a) | Shares | Weighted-Average Fair Value at December 31, 2020 |
| | (in thousands) | | (in thousands) | |
| Performance Shares balance at beginning of period | 67 | $ 64.32 | 67 | |
| Granted | 19 | 81.42 | 19 | |
| Forfeited | (2) | 73.89 | (2) | |
| Vested | (23) | 63.52 | (23) | |
| Performance Shares balance at end of period | 61 | $ 69.71 | 61 | $ 52.42 |

(a) The grant date fair values for the performance shares granted in 2020, 2019 and 2018 were determined by Monte Carlo simulation using a blended volatility of 18%, 21% and 21%, respectively, comprised of 50% historical volatility and 50% implied volatility and the average risk-free interest rate of the three-year United States Treasury security rate in effect as of the grant date.

The weighted-average grant-date fair value of performance share awards granted was as follows in the years ended:

| | Weighted Average Grant Date Fair Value |
|---|---|
| December 31, 2020 | $ 81.42 |
| December 31, 2019 | $ 68.72 |
| December 31, 2018 | $ 61.82 |

Performance plan payouts have been as follows (in thousands):

| Performance Period | Year Paid | Stock Issued | Cash Paid | Total Intrinsic Value |
|---|---|---|---|---|
| January 1, 2017 to December 31, 2019 | 2020 | 14 | $ 1,100 | $ 2,199 |
| January 1, 2016 to December 31, 2018 | 2019 | 44 | $ 2,860 | $ 5,720 |
| January 1, 2015 to December 31, 2017 | 2018 | — | — | — |

On January 27, 2021, the Compensation Committee of our Board of Directors determined that the Company's total shareholder return for the January 1, 2018 through December 31, 2020 performance period was at the 55th percentile of its peer group and confirmed a payout equal to 112.35% of target shares, valued at $3.3 million. The payout was fully accrued at December 31, 2020.

As of December 31, 2020, there was $2.0 million of unrecognized compensation expense related to outstanding performance share plans that is expected to be recognized over a weighted-average period of 1.7 years.

## (17) INCOME TAXES

### CARES Act

On March 27, 2020, President Trump signed the CARES Act, which contained, in part, an allowance for deferral of the employer portion of Social Security employment tax liabilities until 2021 and 2022, as well as a COVID-19 employee retention tax credit of up to $5,000 per eligible employee.

Eligible employers are taxpayers experiencing either: (1) a full or partial suspension of business operations stemming from a government COVID-19 related order or (2) a more than 50% drop in gross receipts compared to the corresponding calendar quarter in 2019. This 50% employee retention tax credit applies up to $10,000 in qualified wages paid between March 13, 2020 through December 31, 2020, and is refundable to the extent it exceeds the employer portion of payroll tax liability.

Eligible wages or employer-paid health benefits must be paid for the period of time during which an employee did not provide services. However, employees do not need to stop providing all services to the employer for the credit to potentially apply.

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Additionally, the CARES Act accelerates the amount of alternative minimum tax ("AMT") credits that can be refunded for the 2018 and 2019 annual tax returns. In 2020, we filed for, and received, a refund of approximately $2.4 million of AMT credit carryforwards under this provision.

During the year ended December 31, 2020, we utilized the payroll tax deferral provision which allowed us to defer payment of approximately $10 million of Social Security employment tax liabilities. We are currently reviewing the potential future benefits of the CARES Act related to employee retention tax credits to assess the impact on our financial position, results of operations and cash flows.

**TCJA**

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the TCJA. The TCJA reduced the U.S. federal corporate tax rate from 35% to 21%. As such, the Company remeasured the deferred income taxes at the 21% federal tax rate as of December 31, 2017. The entities subject to regulatory construct have made their best estimate regarding the probability of settlements of net regulatory liabilities established pursuant to the TCJA. The amount of the settlements may change based on decisions and actions by the federal and state utility commissions, which could have a material impact on the Company's future results of operations, cash flows or financial position. As a result of the revaluation at December 31, 2017, deferred tax assets and liabilities were reduced by approximately $309 million. Of the $309 million, approximately $301 million is related to our regulated utilities and is reclassified to a regulatory liability. During the year ended December 31, 2018, we recorded approximately $11 million of additional regulatory liability associated with TCJA related items primarily related to property, completing the revaluation of deferred taxes pursuant to the TCJA. A majority of the excess deferred taxes are subject to the average rate assumption method, as prescribed by the IRS, and will generally be amortized as a reduction of customer rates over the remaining lives of the related assets. As of December 31, 2020, the Company has amortized $13.3 million of the regulatory liability. The portion that was eligible for amortization under the average rate assumption method in 2020, but is awaiting resolution of the treatment of these amounts in future regulatory proceedings, has not been recognized and may be refunded in customer rates at any time in accordance with the resolution of pending or future regulatory proceedings.

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**Income Tax Expense (Benefit)**

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

| | 2020 | 2019 | 2018 |
|---|---|---|---|
| Current: | | | |
| Federal | $ (6,020) | $ (8,578) | $ 325 |
| State | 847 | 138 | 247 |
| Current income tax expense (benefit) | (5,173) | (8,440) | 572 |
| Deferred: | | | |
| Federal | 35,672 | 34,551 | (25,022) |
| State | 2,419 | 3,469 | 783 |
| Deferred income tax expense (benefit) | 38,091 | 38,020 | (24,239) |
| Income tax expense (benefit) | $ 32,918 | $ 29,580 | $ (23,667) |

**Effective Tax Rates**

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

| | 2020 | 2019 | 2018 |
|---|---|---|---|
| Federal statutory rate | 21.0 % | 21.0 % | 21.0 % |
| State income tax (net of federal tax effect) | 2.4 | 1.5 | 2.3 |
| Non-controlling interest [(a)] | (1.2) | (1.2) | (1.3) |
| Tax credits[(b) (c)] | (9.2) | (3.9) | (2.0) |
| Flow-through adjustments [(d)] | (1.6) | (2.4) | (1.6) |
| Jurisdictional consolidation project [(e)] | — | — | (28.5) |
| Uncertain Tax Benefits | 1.5 | — | — |
| Valuation Allowance | 0.7 | — | — |
| Other tax differences | 0.6 | (1.6) | (0.1) |
| TCJA corporate rate reduction [(f)] | — | — | 1.6 |
| Amortization of excess deferred income tax expense [(g)] | (2.3) | (1.2) | (0.7) |
| Effective Tax Rate | 11.9 % | 12.2 % | (9.3)% |

(a) The effective tax rate reflects the income attributable to the noncontrolling interest in Black Hills Colorado IPP for which a tax provision was not recorded.
(b) The current year increase of PTCs reflect full year production of two wind facilities that were acquired/ placed into service during 2019; Top of Iowa purchased February 2019 and Busch Ranch II with an in-service date of November 2019. Additionally, in November 2020, the Corriedale qualifying wind facility was placed in service.
(c) In 2020, the Company completed a research and development study which encompassed tax years from 2013 to 2019.
(d) Flow-through adjustments related primarily to accounting method changes for tax purposes that allow us to take a current tax deduction for repair costs and certain indirect costs. We recorded a deferred income tax liability in recognition of the temporary difference created between book and tax treatment and flowed the tax benefit through to tax expense. A regulatory asset was established to reflect the recovery of future increases in taxes payable from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record tax benefits consistent with the flow-through method.
(e) In 2018, the Company restructured certain legal entities from earlier acquisitions, which resulted in additional deferred income tax assets of $73 million, related to goodwill that is amortizable for tax purposes, and deferred tax benefits of $73 million.
(f) On December 22, 2017, the TCJA was signed into law reducing the federal corporate rate from 35% to 21% effective January 1, 2018. During the year ended December 31, 2018, we recorded $4.0 million of additional tax expense associated with changes in the prior estimated impacts of TCJA related items.
(g) Primarily TCJA - see above.

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**Deferred Tax Assets and Liabilities**

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

| | 2020 | 2019 |
|---|---|---|
| Deferred tax assets: | | |
| Regulatory liabilities | $ 90,535 | $ 89,754 |
| State tax credits | 23,339 | 23,261 |
| Federal NOL | 96,155 | 120,624 |
| State NOL | 9,914 | 13,537 |
| Partnership | 15,601 | 14,030 |
| Credit Carryovers | 51,445 | 27,139 |
| Other deferred tax assets | 40,143 | 33,395 |
| Less: Valuation allowance | (13,943) | (12,063) |
| Total deferred tax assets | 313,189 | 309,677 |
| Deferred tax liabilities: | | |
| Accelerated depreciation, amortization and other property-related differences | (551,137) | (533,292) |
| Regulatory assets | (28,007) | (23,586) |
| Goodwill | (30,590) | (15,875) |
| State deferred tax liability | (73,910) | (72,911) |
| Other deferred tax liabilities | (38,169) | (24,732) |
| Total deferred tax liabilities | (721,813) | (670,396) |
| Net deferred tax liability | $ (408,624) | $ (360,719) |

**Net Operating Loss Carryforwards**

At December 31, 2020, we have federal and state NOL carryforwards that will expire at various dates as follows (in thousands):

| | Amounts | Expiration Dates | | |
|---|---|---|---|---|
| Federal NOL Carryforward | $ 378,236 | 2022 | to | 2037 |
| Federal NOL Carryforward | $ 79,644 | | No expiration | |
| | | | | |
| State NOL Carryforward [(a)] | $ 173,867 | 2021 | to | 2040 |

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

As of December 31, 2020, we had a $1.1 million valuation allowance against the state NOL carryforwards. Our 2020 analysis of the ability to utilize such NOLs resulted in a $0.8 million increase in the valuation allowance reduced by previously reserved expiring NOL of $0.2 million, which results in an increase to tax expense of $0.8 million net of federal income tax and a decrease to the state NOL deferred tax asset of $0.2 million. The valuation allowance adjustment was primarily attributable to statutory rate reduction for years beyond 2020.

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**Unrecognized Tax Benefits**

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

| | Changes in Uncertain Tax Positions |
|---|---|
| Beginning balance at January 1, 2018 | $ 3,263 |
| Additions for prior year tax positions | 251 |
| Reductions for prior year tax positions | (417) |
| Additions for current year tax positions | 486 |
| Settlements | — |
| Ending balance at December 31, 2018 | 3,583 |
| Additions for prior year tax positions | 446 |
| Reductions for prior year tax positions | (862) |
| Additions for current year tax positions | 998 |
| Settlements | — |
| Ending balance at December 31, 2019 | 4,165 |
| Additions for prior year tax positions | 3,788 |
| Reductions for prior year tax positions | (1,313) |
| Additions for current year tax positions | 1,743 |
| Settlements | — |
| Ending balance at December 31, 2020 | $ 8,383 |

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $4.3 million.

We recognized no interest expense associated with income taxes for the years ended December 31, 2020, December 31, 2019 and December 31, 2018. We had no accrued interest (before tax effect) associated with income taxes at December 31, 2020 and December 31, 2019.

The Company is subject to federal income tax as well as income tax in various state and local jurisdictions. Black Hills Gas, Inc. and subsidiaries, which filed a separate consolidated tax return from BHC and subsidiaries through March 31, 2018, is under examination by the IRS for 2014. BHC is no longer subject to examination for tax years prior to 2017.

As of December 31, 2020, we do not have any tax positions for which it is reasonably possible that the total amount of unrecognized tax benefits will significantly increase or decrease on or before December 31, 2021.

State tax credits have been generated and are available to offset future state income taxes. At December 31, 2020, we had the following state tax credit carryforwards (in thousands):

| State Tax Credit Carryforwards | | Expiration Year |
|---|---|---|
| ITC | $ 23,060 | 2023 to 2041 |
| Research and development | $ 278 | No expiration |

As of December 31, 2020, we had a $12.8 million valuation allowance against the state ITC carryforwards. Our 2020 analysis of the ability to utilize such ITC resulted in a $1.3 million increase in the valuation allowance, which resulted in an increase to tax expense of $1.3 million. The valuation allowance adjustment was primarily attributable to changes in forecasted future state taxable income.

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**(18) BUSINESS SEGMENT INFORMATION**

Our reportable segments are based on our method of internal reporting, which is generally segregated by differences in products, services and regulation. All of our operations and assets are located within the United States.

Accounting standards for presentation of segments require an approach based on the way we organize the segments for making operating decisions and how the Chief Operating Decision Maker (CODM) assesses performance. The CODM assesses the performance of our segments using adjusted operating income, which recognizes intersegment revenues, costs, and assets for Colorado Electric's PPA with Black Hills Colorado IPP on an accrual basis rather than as a finance lease. This presentation of segment information does not impact consolidated financial results.

Segment information was as follows (in thousands):

| Total Assets (net of intercompany eliminations) as of December 31, | 2020 | 2019 |
|---|---|---|
| Electric Utilities | $ 3,120,928 | $ 2,900,983 |
| Gas Utilities | 4,376,204 | 4,032,339 |
| Power Generation | 404,220 | 417,715 |
| Mining | 77,085 | 77,175 |
| Corporate and Other | 110,349 | 130,245 |
| Total assets | $ 8,088,786 | $ 7,558,457 |

| Capital Expenditures [(a)] for the years ended December 31, | 2020 | 2019 |
|---|---|---|
| Electric Utilities | $ 271,104 | $ 222,911 |
| Gas Utilities | 449,209 | 512,366 |
| Power Generation | 9,329 | 85,346 |
| Mining | 8,250 | 8,430 |
| Corporate and Other | 17,500 | 20,702 |
| Total capital expenditures | $ 755,392 | $ 849,755 |

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

| Property, Plant and Equipment as of December 31, | 2020 | 2019 |
|---|---|---|
| Electric Utilities | $ 3,248,480 | $ 3,059,135 |
| Gas Utilities | 3,312,613 | 2,981,498 |
| Power Generation | 534,803 | 534,518 |
| Mining | 187,540 | 180,473 |
| Corporate and Other | 22,094 | 29,055 |
| Total property, plant and equipment | $ 7,305,530 | $ 6,784,679 |

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**Consolidating Income Statement**

| Year ended December 31, 2020 | Electric Utilities | Gas Utilities | Power Generation | Mining | Corporate | Inter-Company Eliminations | Total |
|---|---|---|---|---|---|---|---|
| Revenue - | | | | | | | |
| Contracts with customers | $ 687,929 | $ 959,696 | $ 6,090 | $ 27,089 | $ — | $ — | $ 1,680,804 |
| Other revenues | 2,201 | 9,962 | 1,566 | 2,408 | — | — | 16,137 |
| | 690,130 | 969,658 | 7,656 | 29,497 | — | — | 1,696,941 |
| Inter-company operating revenue - | | | | | | | |
| Contracts with customers | 23,914 | 4,724 | 97,169 | 31,478 | 167 | (157,452) | — |
| Other revenues | — | 288 | 222 | 100 | 352,976 | (353,586) | — |
| | 23,914 | 5,012 | 97,391 | 31,578 | 353,143 | (511,038) | — |
| Total revenue | 714,044 | 974,670 | 105,047 | 61,075 | 353,143 | (511,038) | 1,696,941 |
| Fuel, purchased power and cost of natural gas sold | 267,045 | 354,645 | 8,993 | — | 83 | (138,362) | 492,404 |
| Operations and maintenance, including taxes | 196,794 | 303,577 | 33,695 | 39,033 | 284,501 | (305,823) | 551,777 |
| Depreciation, depletion and amortization | 94,150 | 100,559 | 20,247 | 9,235 | 25,150 | (24,884) | 224,457 |
| Adjusted operating income (loss) | $ 156,055 | $ 215,889 | $ 42,112 | $ 12,807 | $ 43,409 | $ (41,969) | $ 428,303 |
| Interest expense, net | | | | | | | (143,470) |
| Impairment of investment | | | | | | | (6,859) |
| Other income (expense), net | | | | | | | (2,293) |
| Income tax benefit (expense) | | | | | | | (32,918) |
| Income from continuing operations | | | | | | | 242,763 |
| (Loss) from discontinued operations, net of tax | | | | | | | — |
| Net income | | | | | | | 242,763 |
| Net income attributable to noncontrolling interest | | | | | | | (15,155) |
| Net income available for common stock | | | | | | | $ 227,608 |

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**Consolidating Income Statement**

| Year ended December 31, 2019 | Electric Utilities | Gas Utilities | Power Generation | Mining | Corporate | Inter-Company Eliminations | Total |
|---|---|---|---|---|---|---|---|
| Revenue - | | | | | | | |
| Contracts with customers | $ 684,445 | $ 1,007,187 | $ 7,580 | $ 27,180 | $ — | $ — | $ 1,726,392 |
| Other revenues | 5,191 | 384 | 1,859 | 1,074 | — | $ — | 8,508 |
| | 689,636 | 1,007,571 | 9,439 | 28,254 | — | — | 1,734,900 |
| Inter-company operating revenue - | | | | | | | |
| Contracts with customers | 23,116 | 2,459 | 91,577 | 32,053 | 230 | (149,435) | — |
| Other revenues | — | — | 242 | 1,322 | 343,975 | (345,539) | — |
| | 23,116 | 2,459 | 91,819 | 33,375 | 344,205 | (494,974) | — |
| Total revenue | 712,752 | 1,010,030 | 101,258 | 61,629 | 344,205 | (494,974) | 1,734,900 |
| | | | | | | | |
| Fuel, purchased power and cost of natural gas sold | 268,297 | 425,898 | 9,059 | — | 268 | (132,693) | 570,829 |
| Operations and maintenance, including taxes | 195,581 | 301,844 | 28,429 | 40,032 | 286,799 | (303,776) | 548,909 |
| Depreciation, depletion and amortization | 88,577 | 92,317 | 18,991 | 8,970 | 22,065 | (21,800) | 209,120 |
| Adjusted operating income (loss) | 160,297 | 189,971 | 44,779 | 12,627 | 35,073 | (36,705) | 406,042 |
| | | | | | | | |
| Interest expense, net | | | | | | | (137,659) |
| Impairment of investment | | | | | | | (19,741) |
| Other income (expense), net | | | | | | | (5,740) |
| Income tax benefit (expense) | | | | | | | (29,580) |
| Income from continuing operations | | | | | | | 213,322 |
| (Loss) from discontinued operations, net of tax | | | | | | | — |
| Net income | | | | | | | 213,322 |
| Net income attributable to noncontrolling interest | | | | | | | (14,012) |
| Net income available for common stock | | | | | | | $ 199,310 |

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| Year ended December 31, 2018 | Electric Utilities | Gas Utilities | Power Generation | Mining | Corporate | Inter-Company Eliminations | Total |
|---|---|---|---|---|---|---|---|
| | Consolidating Income Statement | | | | | | |
| Revenue - | | | | | | | |
| Contracts with customers | $ 686,272 | $ 1,022,828 | $ 5,833 | $ 33,609 | $ — | $ — | $ 1,748,542 |
| Other revenues | 2,427 | 955 | 1,413 | 931 | — | — | 5,726 |
| | 688,699 | 1,023,783 | 7,246 | 34,540 | — | — | 1,754,268 |
| Inter-company operating revenue - | | | | | | | |
| Contracts with customers | 22,752 | 1,524 | 84,959 | 32,194 | 148 | (141,577) | — |
| Other revenues | — | — | 246 | 1,299 | 379,775 | (381,320) | — |
| | 22,752 | 1,524 | 85,205 | 33,493 | 379,923 | (522,897) | — |
| Total revenue | 711,451 | 1,025,307 | 92,451 | 68,033 | 379,923 | (522,897) | 1,754,268 |
| Fuel, purchased power and cost of natural gas sold | 283,840 | 462,153 | 8,592 | — | 44 | (129,019) | 625,610 |
| Operations and maintenance, including taxes | 186,175 | 291,481 | 25,135 | 43,728 | 324,916 | (336,142) | 535,293 |
| Depreciation, depletion and amortization | 85,567 | 86,434 | 16,110 | 7,965 | 21,161 | (20,909) | 196,328 |
| Adjusted operating income (loss) | 155,869 | 185,239 | 42,614 | 16,340 | 33,802 | (36,827) | 397,037 |
| Interest expense, net | | | | | | | (139,975) |
| Other income (expense), net | | | | | | | (1,180) |
| Income tax benefit (expense) | | | | | | | 23,667 |
| Income from continuing operations | | | | | | | 279,549 |
| (Loss) from discontinued operations, net of tax | | | | | | | (6,887) |
| Net income | | | | | | | 272,662 |
| Net income attributable to noncontrolling interest | | | | | | | (14,220) |
| Net income available for common stock | | | | | | | $ 258,442 |

## (19) SUBSEQUENT EVENT

In February 2021, a prolonged period of historic cold temperatures across the central United States, which covered all of our Utilities' service territories, caused a significant increase in heating and energy demand and contributed to unforeseeable and unprecedented market prices for natural gas and electricity.

Our Utilities have regulatory mechanisms to recover the increased energy costs from this record-breaking cold weather event. However, given the extraordinary impact of these higher costs to our customers, we expect our regulators to undertake a heightened review. We are engaged with our regulators to identify appropriate recovery periods over which to recover costs associated with this event as we continue to address the impacts to our customers' bills.

As a result of this historic event, our natural gas purchases increased by approximately $600 million compared to forecasted base load for the month of February. This amount is a preliminary estimate through February 24, 2021, and does not include certain pipeline transportation charges that remain subject to settlement and payable in late March 2021. To fund February natural gas purchases and pipeline transportation charges and provide additional liquidity, we entered into a nine-month Credit Agreement on February 24, 2021, that provides for an $800 million unsecured term loan facility. The term loan, which matures on November 23, 2021, has an interest rate based on LIBOR plus 75 basis points, carries no prepayment penalty and is subject to the same covenant requirements as our Revolving Credit Facility. We expect to repay a portion of this term loan prior to maturity and refinance the remaining portion in longer-term debt. In the event we are unable to refinance the remaining obligation under the $800 million term loan, we believe it is probable that our current plans to manage liquidity would be sufficient to meet our obligations.

Except as described above and the Note 2 disclosures surrounding Colorado Gas' and Nebraska Gas' jurisdictional consolidation and rate reviews, there have been no events subsequent to December 31, 2020 which would require recognition in the consolidated financial statements or disclosures.

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

None.

## ITEM 9A. CONTROLS AND PROCEDURES

### Disclosure Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 (Exchange Act)) as of December 31, 2020. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective.

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

### Changes in Internal Control over Financial Reporting

During the quarter ended December 31, 2020, there were no changes in the Company's internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting is presented on Page 62 of this Annual Report on Form 10-K.

## ITEM 9B. OTHER INFORMATION

None.

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## PART III

### ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information required under this item with respect to directors and information required by Items 401, 405, 406, 407(c)(3), 407(d)(4) and 407(d)(5) of Regulation S-K, is set forth in the Proxy Statement for our 2021 Annual Meeting of Shareholders, which is incorporated herein by reference. Information about our Executive Officers is reported in Part 1 of this Annual Report on Form 10-K.

### ITEM 11. EXECUTIVE COMPENSATION

Information required under this item is set forth in the Proxy Statement for our 2021 Annual Meeting of Shareholders, which is incorporated herein by reference.

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

Information regarding the security ownership of certain beneficial owners and management is set forth in the Proxy Statement for our 2021 Annual Meeting of Shareholders, which is incorporated herein by reference.

#### EQUITY COMPENSATION PLAN INFORMATION

The following table includes information as of December 31, 2020 with respect to our equity compensation plans. These plans include the 2005 Omnibus Incentive Plan and 2015 Omnibus Incentive Plan.

Equity Compensation Plan Information

| Plan category | Number of securities to be issued upon exercise of outstanding options, warrants and rights | Weighted-average exercise price of outstanding options, warrants and rights | Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) |
|---|---|---|---|
| | (a) | (b) | (c) |
| Equity compensation plans approved by security holders | 154,354 (1) | $ 54.29 (1) | 561,073 (2) |
| Equity compensation plans not approved by security holders | — | $ — | — |
| Total | 154,354 | $ 54.29 | 561,073 |

(1) Includes 149,354 full value awards outstanding as of December 31, 2020, comprised of restricted stock units, performance shares, short-term incentive plan (STIP) units and Director common stock units. The weighted average exercise price does not include the restricted stock units, performance shares, STIP or common stock units. In addition, 195,875 shares of unvested restricted stock were outstanding as of December 31, 2020, which are not included in the above table because they have already been issued.

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

### ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information regarding certain relationships and related transactions and director independence is set forth in the Proxy Statement for our 2021 Annual Meeting of Shareholders, which is incorporated herein by reference.

### ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information regarding principal accounting fees and services is set forth in the Proxy Statement for our 2021 Annual Meeting to Shareholders, which is incorporated herein by reference.

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## PART IV

## ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

**(a) Documents filed as part of this report**

**1. Consolidated Financial Statements**

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

**2. Schedules**

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

**3. Exhibits**

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

| Exhibit Number | Description |
|---|---|
| 2.1 | Purchase and Sale Agreement by and among Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, as Sellers, and Black Hills Utility Holdings, Inc., as Buyer, dated as of July 12, 2015 (filed as Exhibit 2.1 to the Registrant's Form 8-K filed on July 14, 2015). |
| 2.2 | First Amendment to Purchase and Sale Agreement effective December 10, 2015, by and among, Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, as Sellers, and Black Hills Utility Holdings, Inc., as Buyer (filed as Exhibit 2.2 to the Registrant's Form 10-K for 2015). |
| 2.3 | Option Agreement, by and among, Aircraft Services Corporation, as ASC, SourceGas Holdings LLC, as the Company and Black Hills Utility Holdings, Inc., as Buyer (filed as Exhibit 2.2 to the Registrant's Form 8-K filed on July 14, 2015). |
| 3.1 | Restated Articles of Incorporation of the Registrant (filed as Exhibit 3 to the Registrant's Form 8-K filed on February 5, 2018). |
| 3.2 | Amended and Restated Bylaws of the Registrant dated April 24, 2017 (filed as Exhibit 3 to the Registrant's Form 8-K filed on April 28, 2017). |
| 4.1 | Indenture dated as of May 21, 2003 between the Registrant and Wells Fargo Bank, National Association (as successor to LaSalle Bank National Association), as Trustee (filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). |
| 4.1.1 | First Supplemental Indenture dated as of May 21, 2003 (filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). |
| 4.1.2 | Second Supplemental Indenture dated as of May 14, 2009 (filed as Exhibit 4 to the Registrant's Form 8-K filed on May 14, 2009). |
| 4.1.3 | Third Supplemental Indenture dated as of July 16, 2010 (filed as Exhibit 4 to Registrant's Form 8-K filed on July 15, 2010). |
| 4.1.4 | Fourth Supplemental Indenture dated as of November 19, 2013 (filed as Exhibit 4 to the Registrant's Form 8-K filed on November 18, 2013). |
| 4.1.5 | Fifth Supplemental Indenture dated as of January 13, 2016 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on January 13, 2016). |
| 4.1.6 | Sixth Supplemental Indenture dated as of August 19, 2016 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on August 19, 2016). |
| 4.1.7 | Seventh Supplemental Indenture dated as of August 17, 2018 (filed as Exhibit 4.2 to the Registrant's Form 8-K filed on August 17, 2018). |
| 4.1.8 | Eighth Supplemental Indenture dated as of October 3, 2019 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on October 4, 2019). |

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|---|---|
| 4.1.9 | Ninth Supplemental Indenture dated as of June 17, 2020 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on June 17, 2020). |
| 4.2 | Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as Exhibit 4.19 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). |
| 4.2.1 | First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). |
| 4.2.2 | Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant's Post-Effective Amendment No. 2 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). |
| 4.2.3 | Third Supplemental Indenture, dated as of October 1, 2014, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on October 2, 2014). |
| 4.3 | Restated Indenture of Mortgage, Deed of Trust, Security Agreement and Financing Statement, amended and restated as of November 20, 2007, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on October 2, 2014). |
| 4.3.1 | First Supplemental Indenture, dated as of September 3, 2009, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on October 2, 2014). |
| 4.3.2 | Second Supplemental Indenture, dated as of October 1, 2014, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.4 to the Registrant's Form 8-K filed on October 2, 2014). |
| 4.4 | Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000). |
| 4.5 | Description of Securities (filed as Exhibit 4.5 to the Registrant's Form 10-K for 2019) |
| 10.1† | Amended and Restated Pension Equalization Plan of Black Hills Corporation dated November 6, 2001 (filed as Exhibit 10.11 to the Registrant's Form 10-K/A for 2001). |
| 10.1.1† | First Amendment to Pension Equalization Plan (filed as Exhibit 10.10 to the Registrant's Form 10-K for 2002). |
| 10.1.2† | Grandfather Amendment to the Amended and Restated Pension Equalization Plan of Black Hills Corporation (filed as Exhibit 10.2 to the Registrant's Form 10-K for 2008). |
| 10.2† | 2005 Pension Equalization Plan of Black Hills Corporation (filed as Exhibit 10.3 to the Registrant's Form 10-K for 2008). |
| 10.3† | Restoration Plan of Black Hills Corporation (filed as Exhibit 10.5 to the Registrant's Form 10-K for 2008). |
| 10.3.1† | First Amendment to the Restoration Plan of Black Hills Corporation dated July 24, 2011 (filed as Exhibit 10.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2011). |
| 10.4† | Black Hills Corporation Non-qualified Deferred Compensation Plan as Amended and Restated effective January 1, 2011 (filed as Exhibit 10.4 to the Registrant's Form 10-K for 2010). |
| 10.4.1† | First Amendment to the Black Hills Corporation Nonqualified Deferred Compensation Plan as Amended and Restated effective January 1, 2011 (filed as Exhibit 10.5 to the Registrant's Form 10-K for 2018). |
| 10.5† | Black Hills Corporation Post-2018 Nonqualified Deferred Compensation Plan (filed as Exhibit 10.6 to the Registrant's Form 10-K for 2018). |
| 10.6† | Black Hills Corporation 2005 Omnibus Incentive Plan ("Omnibus Plan") (filed as Appendix A to the Registrant's Proxy Statement filed April 13, 2005). |
| 10.6.1† | First Amendment to the Omnibus Plan (filed as Exhibit 10.11 to the Registrant's Form 10-K for 2008). |
| 10.6.2† | Second Amendment to the Omnibus Plan (filed as Exhibit 10 to the Registrant's Form 8-K filed on May 26, 2010). |
| 10.7*† | Black Hills Corporation Amended and Restated 2015 Omnibus Incentive Plan effective January 26, 2021. |
| 10.8† | Form of Stock Option Agreement for Omnibus Plan effective for awards granted on or after January 1, 2014 (filed as Exhibit 10.7 to the Registrant's Form 10-K for 2013). |
| 10.9† | Form of Stock Option Agreement effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.8 to Registrant's Form 10-K for 2015). |
| 10.10† | Form of Restricted Stock Award Agreement for 2015 Omnibus Incentive Plan effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.10 to Registrant's Form 10-K for 2015). |

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|---|---|
| 10.11*† | Form of Restricted Stock Award Agreement for 2015 Omnibus Incentive Plan effective for awards granted on or after January 26, 2021. |
| 10.12† | Form of Restricted Stock Unit Award Agreement for 2015 Omnibus Plan effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.12 to the Registrant's Form 10-K for 2015). |
| 10.13† | Form of Performance Share Award Agreement effective for awards granted on or after January 1, 2016 (filed as Exhibit 10.6 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2016). |
| 10.14† | Form of Performance Share Award Agreement effective for awards granted on or after January 1, 2017 (filed as Exhibit 10.12 to the Registrant's Form 10-K for 2019). |
| 10.15† | Form of Short-term Incentive Plan for Officers Award Agreement effective for awards granted on or after January 1, 2016 (filed as Exhibit 10.7 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2016). |
| 10.16*† | Form of Short-term Incentive Plan for Officers Award Agreement effective for awards granted on or after January 1, 2021. |
| 10.17*† | Form of Performance Unit Award Agreement for 2015 Omnibus Incentive Plan effective for awards granted on or after January 1, 2021. |
| 10.18† | Form of Indemnification Agreement (filed as Exhibit 10.5 to the Registrant's Form 8-K filed on September 3, 2004). |
| 10.19† | Change in Control Agreement dated November 15, 2019 between Black Hills Corporation and Linden R. Evans (filed as Exhibit 10.15 to the Registrant's Form 10-K for 2019). |
| 10.20† | Change in Control Agreements between Black Hills Corporation and its non-CEO Senior Executive Officers (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2019). |
| 10.21† | Outside Directors Stock Based Compensation Plan as Amended and Restated effective January 1, 2009 (filed as Exhibit 10.23 to the Registrant's Form 10-K for 2008). |
| 10.21.1† | First Amendment to the Outside Directors Stock Based Compensation Plan effective January 1, 2011 (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2010). |
| 10.21.2† | Second Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2013 (filed as Exhibit 10.15 to the Registrant's Form 10-K for 2012). |
| 10.21.3† | Third Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2015 (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2014). |
| 10.21.4† | Fourth Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2017 (filed as Exhibit 10.4 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2016). |
| 10.21.5† | Fifth Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2018 (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2017). |
| 10.21.6† | Sixth Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2019 (filed as Exhibit 10.18 to the Registrant's Form 10-K for 2018). |
| 10.22† | Form of Non-Disclosure and Non-Solicitation Agreement for Certain Employees (filed as Exhibit 10.8 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2016). |
| 10.23 | Equity Distribution Sales Agreement dated August 4, 2020 among Black Hills Corporation and the several Agents named therein (filed as Exhibit 1.1 to the Registrant's Form 8-K filed on August 4, 2020). |
| 10.24 | Third Amended and Restated Credit Agreement dated as of July 30, 2018 (relating to $750 million Revolving Credit Facility), among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and U.S. Bank, National Association, as Administrative Agent (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on July 31, 2018). |
| 10.25 | Amended and Restated Credit Agreement dated as of July 30, 2018 (relating to $300 million, two-year term loan), among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on July 31, 2018). |
| 10.25.1 | First Amendment dated as of June 17, 2019 to Amended and Restated Credit Agreement dated as of July 30, 2018, among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Registrant's Form 8–K filed on June 17, 2019). |

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| 10.26 | Coal Leases between WRDC and the Federal Government<br>-Dated May 1, 1959 (filed as Exhibit 5(i) to the Registrant's Form S-7, File No. 2-60755)<br>-Modified January 22, 1990 (filed as Exhibit 10(h) to the Registrant's Form 10-K for 1989)<br>-Dated April 1, 1961 (filed as Exhibit 5(j) to the Registrant's Form S-7, File No. 2-60755)<br>-Modified January 22, 1990 (filed as Exhibit 10(i) to Registrant's Form 10-K for 1989)<br>-Dated October 1, 1965 (filed as Exhibit 5(k) to the Registrant's Form S-7, File No. 2-60755)<br>-Modified January 22, 1990 (filed as Exhibit 10(j) to the Registrant's Form 10-K for 1989). |
| 10.27 | Assignment of Mining Leases and Related Agreement effective May 27, 1997, between WRDC and Kerr-McGee Coal Corporation (filed as Exhibit 10(u) to the Registrant's Form 10-K for 1997). |
| 21* | List of Subsidiaries of Black Hills Corporation. |
| 23.1* | Consent of Independent Registered Public Accounting Firm. |
| 31.1* | Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002. |
| 31.2* | Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002. |
| 32.1* | Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| 32.2* | Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| 95* | Mine Safety and Health Administration Safety Data |
| 101.INS* | 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* | XBRL Taxonomy Extension Schema Document |
| 101.CAL* | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.DEF* | XBRL Taxonomy Extension Definition Linkbase Document |
| 101.LAB* | XBRL Taxonomy Extension Label Linkbase Document |
| 101.PRE* | XBRL Taxonomy Extension Presentation Linkbase Document |
| 104* | Cover Page Interactive Data File (formatted as inline XBRL and contained in Exhibit 101) |

**ITEM 16. FORM 10-K SUMMARY**

None.