READY TO SERVE

2020 Annual Report | Proxy Statement | Form 10-K

Black Hills Corporation
Ready

BLACK HILLS CORPORATION

BKH

We are a customer focused, growth-oriented utility company with a tradition of exemplary service and a vision to be the energy partner of choice. Based in Rapid City, South Dakota, the company serves 1.3 million electric and natural gas utility customers in 823 communities in Arkansas, Colorado, Iowa, Kansas, Montana, Nebraska, South Dakota and Wyoming. Employees partner to produce results that Improve Life with Energy.

Arkansas
178,300 utility customers
100 communities served

Colorado
296,600 utility customers
119 communities served
597 megawatts of owned power generation capacity

Iowa
161,000 utility customers
133 communities served
80 megawatts of owned power generation capacity

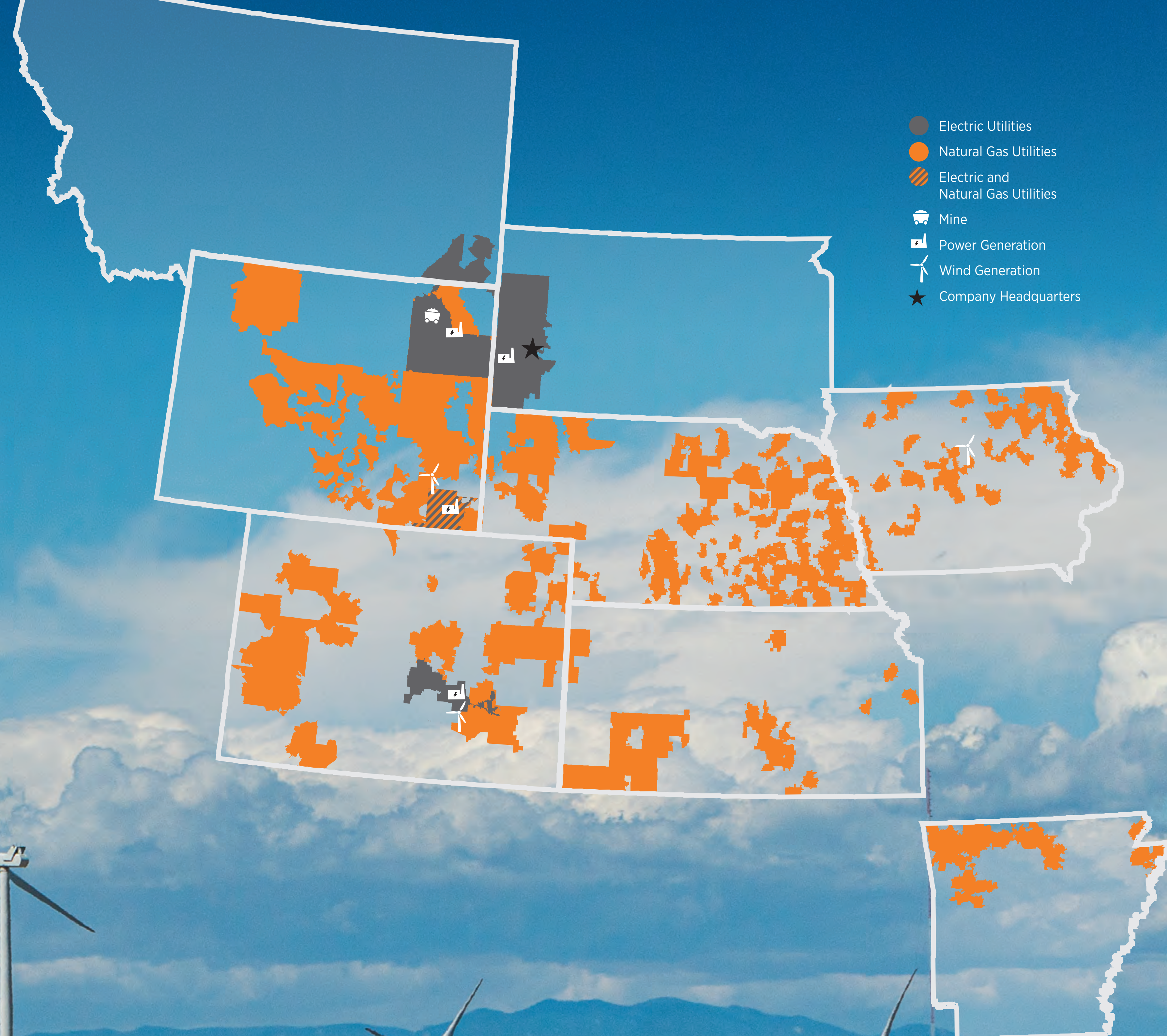
Kansas
117,000 utility customers
65 communities served

Montana
47 utility customers
2 communities served

Nebraska
296,800 utility customers
319 communities served

South Dakota
71,000 utility customers
29 communities served
130 megawatts of owned power generation capacity

Wyoming
178,600 utility customers
56 communities served
189 million tons of coal reserves
608 megawatts of owned power generation capacity



Busch Ranch II Wind Energy Project, Southern Colorado

DEAR FELLOW SHAREHOLDERS,

Ready to Serve. Words that define and affirm the unwavering commitment of the 3,000 team members of Black Hills Corporation to provide essential, life-saving energy to our customers. We are humbled by this responsibility and consider it a privilege to serve as an integral partner to our customers and communities, delivering safe and reliable electricity and natural gas to nearly 1.3 million businesses, households and families across our 8-state service territory.

We chose Ready to Serve as the theme of this year's report because it speaks to our deeply held values and to our preparation and resilience as an organization to respond quickly and confidently to whatever comes our way. In a year upended by the global coronavirus pandemic (COVID-19) and subdued by its devastating impact, our work has never been more important, nor more urgent.

We couldn't be prouder of our Black Hills Energy team, as they worked together during these challenging times — distanced and working remotely — ready to serve those who depend on us. Our team adapted quickly to the ever-changing environment, staying on the forefront of processes and safeguards, resolved to do their part to help reduce the spread of the virus.

2020 was a difficult year for our customers and communities, and we're working hard to support them. Our hearts go out to all those impacted by COVID-19, as we witness the toll taken on individuals, families, and businesses.

In April, during the early weeks of the pandemic, our Black Hills Corporation Foundation worked quickly to provide assistance to our communities through gifts totaling more than $375,000 to support food insecurity programs and critical services provided by local charities including United Way chapters and Salvation Army corps across each of our states. We also proactively established moratoriums on utility disconnections and kept them in place weeks, and in some cases, months, after state-issued moratoriums had been lifted.

In 2020, our community support totaled $5.6 million, including over $628,000 in employee giving to United Way chapters and affiliates across our service territory and more than $812,000 in expanded energy assistance funding through our Black Hills Cares program, which matches customers' and employees' charitable contributions dollar-for-dollar.

We have been by our customers' sides throughout many challenges over our 137-year history and will continue to do so through this challenge, too. Our care for our customers runs deep and is reflected in the confidence and commitment of our Black Hills Energy team members, working each day in service to our customers, guided by our values and united in our mission of Improving Life with Energy.

We are Ready to Serve.

DELIVERING STRONG FINANCIAL RESULTS

To safely and reliably serve our customers and support our communities, we took bold actions in 2020 to ensure a sustainable path forward for our company. With the activation of our business continuity plans, and a determined and dedicated team, we successfully delivered on our long-term strategy to serve our customers' energy needs today and well into the future.

Rising above the challenges of the year, we reported strong financial results in 2020, increased our dividend and delivered on our customer-centered capital investment plans. Financial results were solid with earnings, as adjusted, of $3.73* per share, up 5.7% compared to $3.53 in 2019. Results were driven by strong operational execution, disciplined cost management and fair returns on invested capital.

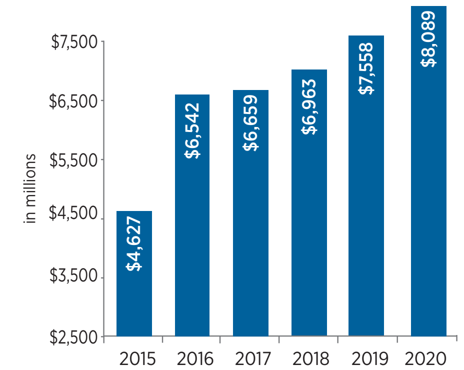
After an excellent start to 2020, and an outstanding stock price performance in 2019, our stock declined sharply in March as uncertainty surrounding the pandemic rattled investors. As the economy started to recover in the third quarter, investors rotated into higher growth opportunities, leaving the utility sector lagging for the remainder of the year. Our stock price had a strong run to finish the year, up nearly 15% in the fourth quarter. For the full year, our stock price performance was down 21.8%. Meanwhile, our 5-year stock price performance was up 32.4%, delivering a total shareholder return of 54.2%, including dividends, over that period.

We celebrated a major milestone with our shareholders in 2020 when we completed the 50th consecutive year of dividend increases after we increased our dividend by $0.12, or 5.9%, to $2.17 per share. This is the second longest track record in the gas and electric utility sector and speaks to the leadership, vision and perseverance of our company. We are equally proud that the company has paid dividends to our shareholders every year since 1942, or 78 years, another illustration of our resiliency and commitment to creating sustainable value for our shareholders.

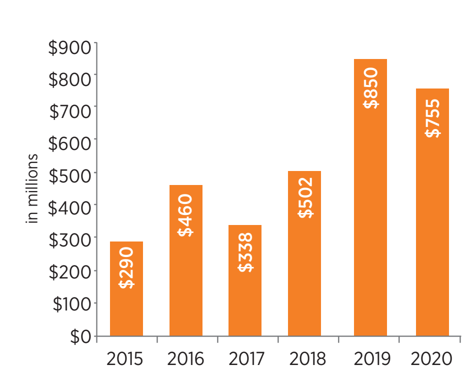
Our long-term planning and financing strategy prepared us with ample access to short-term and long-term funding during the pandemic. We maintained a $750 million credit line during the year, providing strong access to liquidity to fund our operations and capital program. We also completed equity and bond offerings during the year to strengthen our balance sheet. We executed a $100 million equity offering with a single investor in February at a stock price of $81.77 per share and completed a $400 million, 10-year bond offering in June priced at an attractive rate of 2.5%.

In a year of heightened stakeholder concerns stemming from the pandemic, as well as climate change, carbon emissions and Environmental, Social and Governance (ESG) considerations in general, we expanded our disclosures to better showcase how Black Hills Corp. is transitioning to a cleaner energy future while continuing our tradition of good governance. With a thoughtful and confident investment plan, and excitement around new business opportunities, we are Ready to Serve and committed to delivering long-term value to you, our shareholders.

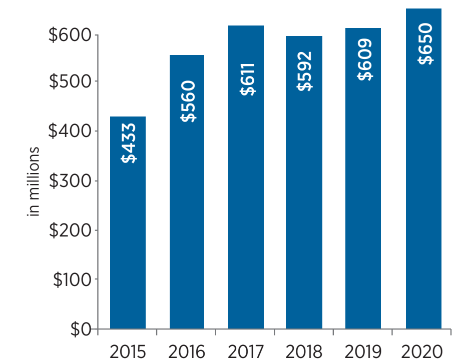
Total assets



Capital expenditures[1]

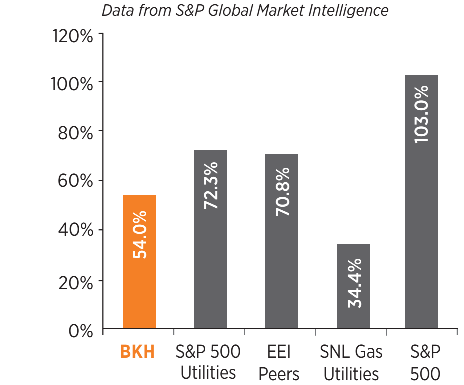


EBITDA, as adjusted[2]

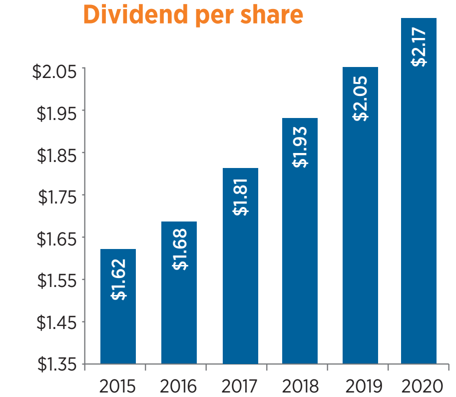


5-year total shareholder return

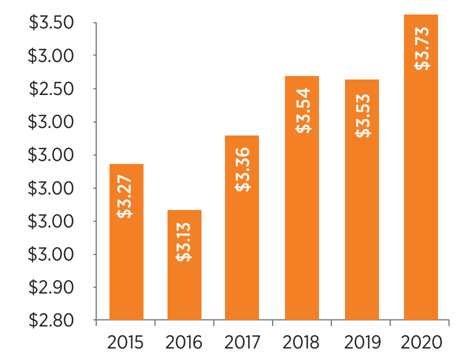
Data from S&P Global Market Intelligence



Dividend per share



Earnings per share, as adjusted[2]



(In millions except per share amounts)

		2020	2019	2018
STOCK INFORMATION (year-end)	Stock price per share	$61.45	$78.54	$62.78
	Common shares outstanding	62.8	61.5	60.0
	Market capitalization	$3,859	$4,828	$3,767
COMPANY KEY INDICATORS	Total capital expenditures	$755	$850	$502
	Total assets	$8,089	$7,558	$6,963
	Total debt	$3,771	$3,495	$3,142
	Net income available for common stock	$228	$199	$258
PER SHARE INFORMATION	Earnings per share: GAAP	$3.65	$3.28	$4.66
	Earnings per share, as adjusted[2]	$3.73	$3.53	$3.54
	Dividend per share	$2.17	$2.05	$1.93
	Dividend yield at year-end	3.5%	2.6%	3.1%
	Dividend growth	5.9%	6.2%	6.6%

Note: all metrics are from continuing operations

1 Excludes capital for SourceGas purchase in 2016

2 Non-GAAP measure reconciled to GAAP starting on page A-1

** Non-GAAP measure reconciled to GAAP starting on page A-1*

STAYING POWER:

Celebrating 50 consecutive years of annual dividend increases in 2020

Black Hills Corp.'s dividend track record reflects our company's long-term commitment to customers. It speaks volumes about our values and our staying power over decades of change and challenges.

1883
Our company got its start in Deadwood, South Dakota

1941
Black Hills Power and Light Company becomes a publicly-traded company

$1 million of preferred and common stock issued

Board establishes first dividend for investors

1970
50-year track record begins for annual dividend increases

1980
Black Hills Power and Light listed on the NYSE

1986
Name changed to Black Hills Corporation

2005
Acquisition of Cheyenne Light, Fuel and Power — first entry into natural gas distribution business

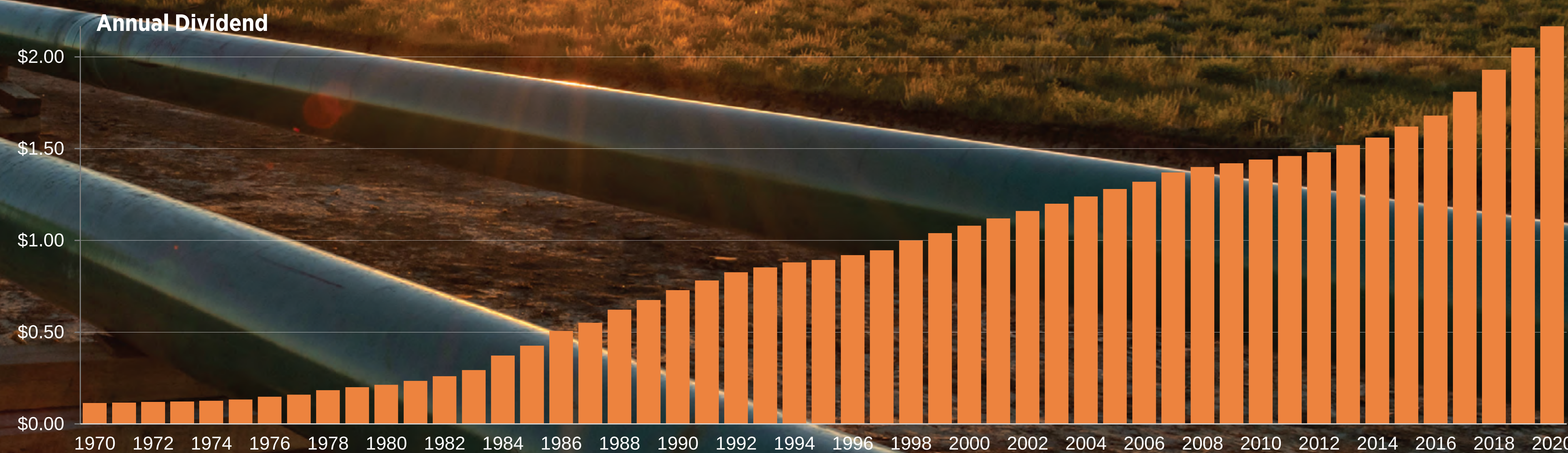
2008
Acquisition of Aquila assets adds 4 natural gas utilities and 1 electric utility

2016
Acquisition of SourceGas adds 4 additional natural gas utilities, company size increases by 50%

2018
Black Hills Corp. leadership team rings the opening bell at NYSE to celebrate 135 years of delivering energy to customers

2020
Black Hills Corp. stock hits all-time closing high of $85.53

50th anniversary of annual dividend increases



Note: annual dividends adjusted for stock splits.

DELIVERING OPERATIONAL EXCELLENCE

During a year challenged by the pandemic, our team successfully executed our customer-focused capital investment program, prudently deploying $755 million in 2020 to improve the safety, reliability and resiliency of our extensive electric and natural gas infrastructure systems, while also expanding our renewable energy offerings. With significant projects completed in 2020, such as the construction and on-time delivery of our 52.5-megawatt Corriedale Wind Energy Project in Cheyenne, Wyoming, we were especially proud of the close collaboration with our contractors, suppliers and communities, as we kept people safely employed during the pandemic while delivering lasting value for our customers.

We operate one of the largest natural gas and electric infrastructure systems in the country, with 46,000 miles of natural gas lines and 9,000 miles of electric transmission and distribution lines spanning 1,600 miles across eight geographically diverse states. To better serve our customers and mitigate risks across our extensive system, we take a programmatic approach to maintaining, upgrading and prioritizing our capital investments. We are forecasting more than $3 billion of capital investment in 2021 through 2025 to further enhance the safety and reliability of our infrastructure and meet our customers' growing energy needs.

With this significant level of customer-focused investment, we are continuing to expand our use of Digital As-Built technology and data, as an industry leader and as a best practice, to ensure the safety of our natural gas infrastructure and related construction activities. In 2020, we completed a years-long, company-wide rollout and adoption of the Digital As-Built platform in each of our six gas states. With this innovative technology now in place, we have equipped our employees with leading edge tools to accurately document and map our natural gas assets.

To further enhance the safety of our natural gas operations, we launched a multi-year, multi-faceted data improvement program consisting of Global Positioning System surveys of our pipelines, the digitization of historical paper records and an update of critical data components. Our teams are transferring this data into the company's Geographic Information System, making the data easily accessible to our employees in the field and to multiple functions across the company. These new data tools and capabilities provide significant benefit in evaluating risks on our pipeline systems, designing new pipeline systems and upgrades, preventing third party damages, and managing compliance reporting activities.

2020 PEAK SYSTEM DEMAND*

(in megawatts)

Our electric utilities continue to deliver top reliability performance year after year, ranking consistently among the top 25% of all electric utilities in the nation. This dedication to excellence ensures our customers have access to uninterrupted service, critical to the health and well-being of our families, businesses and communities.

Colorado	Summer	401
	Winter	297
South Dakota	Summer	378
	Winter	315
Wyoming	Summer	271**
	Winter	232

* Peak System Demand represents the highest point of customer usage for a single hour for the system in total. Our system peaks include demand loads for 100% of plants regardless of joint ownership.

** New record for peak demand

READY TO MAKE TOMORROW EVEN BETTER THAN TODAY

Ready to Serve gives added meaning to the actions we take and the decisions we make each day to support our customers' changing energy needs and future requirements. Our mission of Improving Life with Energy means we must be ready to make tomorrow even better than today. That's why in 2020 we formalized our sustainability strategy and set enterprise-wide clean energy goals to reduce the greenhouse gas (GHG) emissions intensity from our natural gas utilities and electric operations.

Our goals call for the reduction of GHG emissions intensity of our natural gas operations of 50% by 2035 and GHG reductions from our electric utilities of 40% by 2030 and 70% by 2040, based on 2005 levels. While ambitious, our goals are achievable using technology available today and based on 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.

Our progress to date demonstrates our commitment to environmental responsibility. We have reduced the GHG emissions intensity of our electric operations by 25% since 2005, which includes owned generation and purchased power, and we have reduced the GHG emissions intensity of our natural gas operations by more than a third since 2005. Our Colorado electric utility — with an all-renewable and natural gas generating fleet, one of the cleanest in the state — has already achieved a 50% reduction in GHG emissions since 2005 and is on track to reach 80% reduction by 2030, a state policy objective.

EPA METHANE CHALLENGE

Through the Methane Challenge Program, the EPA encourages partners to make voluntary commitments to reduce methane emissions through broad scale implementation of cost-effective technologies and practices in their natural gas pipeline systems. In 2020, as a further demonstration of our sustainability goals, we joined the Methane Challenge and have committed to three Best Management Practices: Distribution Mains Replacement, Distribution Services Replacement and Excavation Damages, which makes us an industry leader in challenge commitments. By joining this program, we will showcase our planned pipe replacements and associated GHG emissions reductions on a national level.

Pipeline replacement in Laramie, Wyoming

DELIVERING SUSTAINABLE ENERGY SOLUTIONS

As we continue to strengthen and evolve our sustainability strategy, we will build upon our success of delivering strong returns for investors by seeking renewable energy growth opportunities and creating solutions to meet stakeholders' evolving expectations.

In 2020, we expanded our renewable energy portfolio and our offerings to customers. Highlights include:

RENEWABLE NATURAL GAS

The challenge of providing customers with both sustainability and energy choice is a priority for our company, and one of the critical pieces of that puzzle is Renewable Natural Gas (RNG). RNG reduces the impacts of organic wastes, provides economic opportunities in the communities we serve, and is a clean, affordable and reliable energy option that can readily be used in natural gas infrastructure and for use in customers' homes and businesses.

We have a long history with RNG, beginning in 2008 with our first RNG project at a landfill in Lincoln, Nebraska. Since then, RNG has become a major focal point of energy companies across the country, and we're ready to strategically incorporate more of this renewable energy source into our business. To support this objective, we launched a team in 2020 to develop an enterprise RNG strategy and pursue additional RNG projects in our service territories. With four RNG projects in service, 12 additional projects active, and 60 others identified, we see great potential to generate RNG supplies throughout our multi-state agricultural service area.

NATURAL GAS – ESSENTIAL TO OUR CLEAN ENERGY FUTURE

Natural gas provides the clean energy we need now and will be an essential piece of our clean energy future. Sustainably reducing GHG emissions will require partnership among clean energy sources like renewables and natural gas, the leverage of our country's infrastructure, and careful consideration of the cost impact to our customers. We believe that by innovating, natural gas can continue to fuel our communities for many future generations.

Historic Hotel Colorado, Glenwood Springs, Colorado

RENEWABLE READY AND CORRIEDALE

We continue to deliver on our commitment to provide clean energy and creative solutions as the energy provider of choice for our customers. In November, we completed construction on our $79 million Corriedale Wind Energy Project, serving the energy needs of our Renewable Ready subscribers in South Dakota and Wyoming. We are extremely proud of this achievement as our team delivered this 52.5-megawatt wind energy project on schedule and on budget during the ongoing COVID-19 pandemic.

Our Renewable Ready program demonstrates our team's entrepreneurial spirit to find customer-centric solutions through a voluntary renewable energy offering with innovative tariffs in states without renewable energy mandates. Customer interest in this program was so strong we upsized the wind energy project from 40 megawatts to 52.5 megawatts.

We recognize that the demand for renewable energy is growing, especially among our high-use customers and businesses. This customer demand is driving the market for renewable generation. With our Renewable Ready program, we can provide our customers with a clean energy option that supports the expansion of affordable renewable energy in our region.

RENEWABLE ADVANTAGE

In September, the Colorado Public Utilities Commission approved our Renewable Advantage plan to add 200-megawatts of utility-scale solar to our Colorado electric system. When Renewable Advantage comes online in 2023, more than half of our total electric generation mix in Colorado will come from renewable sources, leading to a 70% emissions reduction by 2024, compared with 2005. This positions the company well to achieve the state's objective of an 80% emissions reduction by 2030.

In addition to its environmental benefits, our Renewable Advantage plan will deliver significant economic benefits including an estimated $66 million in customer cost savings over 15 years, a projected $178 million in direct and indirect economic impact to the region through state, local and federal taxes, and 250 good-paying construction jobs.

READY EV

Our Ready EV rebate program, launched in late 2019 in South Dakota and Wyoming, is making electric vehicle charging more convenient and more affordable for our customers. With more than 40 different types of electric vehicles on the market today, we know customer demand will keep growing as technology continues to improve and more charging options become available.

In May, we submitted our Colorado Ready EV plan to the Colorado Public Utilities Commission for review, and approval is expected in mid-2021. Our plan addresses clean energy policy objectives that call on public utilities to support the widespread adoption of electric vehicles through the electrification of the transportation sector. If approved, our Colorado Ready EV plan will provide customer rebates to significantly lower the cost of electric vehicle charging equipment, establish rate options that could lead to bill savings, and expand the commercial infrastructure needed to make EV charging more accessible to drivers.

Our growing wind generation portfolio
With the completion of the Corriedale Wind Energy Project, Black Hills Corp. now owns and operates 281 megawatts of renewable wind generation with an additional 132 megawatts of wind energy under contract, representing 25% of the company's total owned and contracted generation.

Pueblo, Colorado

ENGAGING STAKEHOLDERS

In 2020, we advanced several key initiatives in support of our customers.

COLORADO

Voters in a special election in Pueblo, Colo., elected to retain the company's Colorado electric franchise agreement. In a record turnout for the community, 77% of voters chose to retain Black Hills Energy as their energy provider. We will continue to responsibly and efficiently serve our customers as one of the most reliable electric utilities in the country and as a leading renewable energy provider. By voting in favor of Black Hills Energy, the citizens of Pueblo chose to maintain their existing franchise agreement with the company, which continues through 2030.

When our Black Hills Colorado Gas rate review application was dismissed by the Colorado Public Utilities Commission in early 2021, we began evaluating options for recovery on infrastructure investments made to ensure the safety and reliability of our 7,000-mile natural gas pipeline system. In a separate application, the system safety and integrity rider to recover safety-focused investments continues to advance through the regulatory process.

NEBRASKA

The Nebraska Public Service Commission approved a settlement agreement in early 2021 on behalf of our Black Hills Nebraska Gas utility to consolidate rate schedules into a new, single statewide structure, improving efficiency and customer service. The settlement agreement also recovers infrastructure investments made over the last decade in safety, reliability and system integrity for natural gas service to approximately 300,000 customers across 319 Nebraska communities. This settlement agreement will shift approximately $4.6 million of rider revenue to base rates and will generate an estimated $6.5 million in new annual base rate revenues effective March 1, 2021. It also allows us to expand our system safety and integrity rider across our entire Nebraska service area to recover the costs of safety infrastructure projects for the next five years.

WYOMING

In October, our Wyoming electric utility subsidiary Cheyenne Light, Fuel and Power Co., doing business as Black Hills Energy, and power generation subsidiary Black Hills Wyoming, received approval from the Federal Energy Regulatory Commission of their joint application for a proposed 60-megawatt power purchase agreement.

The new long-term power purchase agreement will provide the capacity and energy needed to help maintain grid stability and resiliency as our Wyoming electric utility integrates more intermittent renewable resources into its generating fleet.

Under the 11-year agreement, commencing on Jan. 1, 2022, and ending Dec. 31, 2032, Black Hills Wyoming will continue to deliver 60 megawatts of base load capacity and energy to Cheyenne Light from its Wygen I power plant located near Gillette in northeast Wyoming. The FERC approval allows the Wygen I power plant to continue serving our Wyoming electric utility customers with stable, low-cost, base load energy afforded by mine-mouth logistics and a low-cost, local Wyoming energy resource.

We are proud of the way our team responded during this year of challenge and uncertainty. Our corporate response planning and preparedness allowed us to quickly mobilize as an organization to put in motion new safety procedures and operational plans to effectively manage our business and better serve our customers through these challenges.

We are committed to being the safest utility company in the nation and this requires persistent, daily attention in all we do. With this dedication and focus, our journey to zero workplace injuries is not only possible, but within our reach. In 2020, we achieved our best safety performance ever, with a Total Case Incident Rate (incidents per 200,000 hours worked) of 1.0, an improvement of 78% over the past decade, and well below the utility industry average of 2.2. While pleased by this performance, we remain committed to working together to continuously improve, as even one injury is one too many.

As we look back on the year and all we have learned, we have much to be proud of and much to be grateful for. Firmly grounded in our values, we confirmed that our Black Hills Energy team is a family that looks out for one another and goes the extra mile to help others in need.

We learned that staying connected matters to us and to our customers — whether by phone, virtually, or at 6-feet apart. We learned that with open and honest communication and the tone set at the top, we became stronger and more effective as an organization. Enabled by technology, we learned new and creative ways to collaborate with one another to better serve our customers and drive projects to completion.

We accomplished a great deal in 2020 and remain confident in our future. With a customer-focused long-term plan, combined with a solid financial strategy, we are Ready to Serve the growing needs of our customers and communities as we Improve Life with Energy.

As we close this letter, we would like to take a moment to welcome two new independent directors to the Black Hills Corp. board of directors, Barry Granger and Scott Prochazka. With their credentials and experience, they will help drive our future growth plans and fulfill our ESG commitments.

Thank you for the confidence and trust you have placed in our company. We are looking forward to a safe and productive year ahead.

Sincerely,

Steven R Mills

Steve Mills,
Chairman, Black Hills Corp. Board of Directors

Linn Evans

Linn Evans,
President and CEO, Black Hills Corp.

We couldn't be prouder of our Black Hills Energy team, as they worked together during these challenging times — distanced and working remotely — ready to serve those who depend on us.

PROXY

BLACK HILLS CORPORATION

Notice of 2021
Annual Meeting of Shareholders
and Proxy Statement

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BLACK HILLS CORPORATION

NOTICE OF ANNUAL MEETING OF SHAREHOLDERS

WHEN:

Tuesday, April 27, 2021
9:30 a.m., local time

WHERE:

Horizon Point
Company's Corporate Headquarters
7001 Mount Rushmore Road
Rapid City, South Dakota 57702

We are pleased to invite you to attend the annual meeting of shareholders of Black Hills Corporation.

Although we will hold our annual meeting in person, we are sensitive to the public health and travel concerns our shareholders may have and the protocols that federal, state, and local governments may impose due to the COVID-19 pandemic. In the event it is not possible or advisable to attend our annual meeting in person, we encourage you to listen to the webcast of the meeting online at https://blackhillsenergy.zoom.us/j/91066914257. Please note, if you attend online, you will not be able to vote your shares or submit questions. Accordingly, it is important that you vote your shares as instructed below.

Proposals:

1. Election of one director in Class II: Scott M. Prochazka; and four directors in Class III: Linden R. Evans, Barry M. Granger, Tony A. Jensen, and Steven R. Mills.
2. Ratification of Deloitte & Touche LLP to serve as our independent registered public accounting firm for 2021.
3. Adoption of an advisory, non-binding resolution to approve our executive compensation.
4. Any other business that properly comes before the annual meeting.

Record Date:

The Board of Directors set March 8, 2021 as the record date for the meeting. This means that our shareholders as of the close of business on that date are entitled to receive this notice of the meeting and vote at the meeting and any adjournments or postponements of the meeting.

How to Vote:

Your vote is very important. You may vote your shares by telephone, by the Internet or by returning the enclosed proxy. If you own shares of common stock other than the shares shown on the enclosed proxy, you will receive a proxy in a separate envelope for each such holding. Please vote each proxy received. To make sure that your vote is counted if voting by mail, you should allow enough time for the postal service to deliver your proxy before the meeting.

Sincerely,

/s/ Amy K. Koenig
AMY K. KOENIG
Vice President - Governance, Corporate Secretary and Deputy General Counsel

PROXY SUMMARY

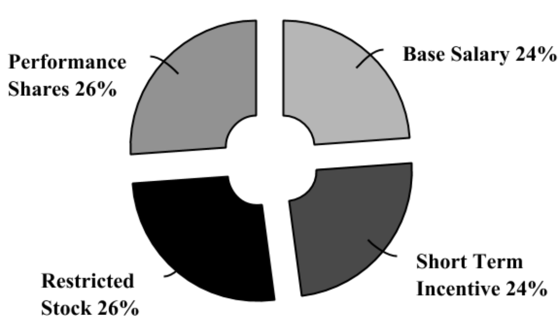
Items of Business to be Considered at the Annual Meeting

Proposal		Board Recommendation	Page
1	Election of Directors	☑ FOR each Director Nominee	6
2	Ratification of Deloitte & Touche LLP to Service as Independent Registered Public Accounting Firm for 2021	☑ FOR	22
3	Advisory Non-Binding Resolution to Approve Executive Compensation	☑ FOR	52

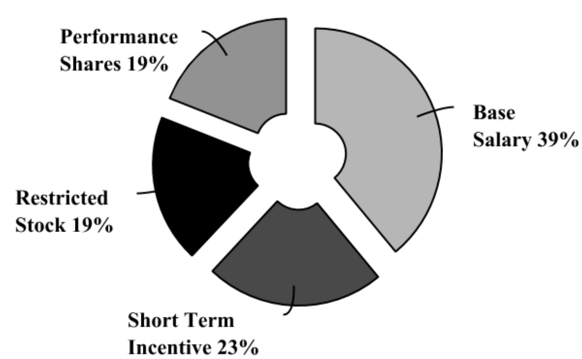
Executive Pay Overview

We have an Executive Compensation Philosophy that establishes the framework our Compensation Committee applies in structuring compensation for our executive officers (“Named Executive Officers” or “NEOs”). The components of our executive pay program consist of a base salary, a short-term incentive plan, and long-term incentives. Our executive pay program aligns the interest of our Named Executive Officers with our stakeholders by tying incentive pay to achievement of performance metrics.

CEO Target Pay Mix



NEOs' Target Pay Mix (Average)



Variable	77 %	Variable	61 %
Linked to Share	53 %	Linked to Share	37 %

* Percentages may differ from above due to rounding.

The performance measures for our incentive compensation plans are discussed in greater detail on page 27 of the Proxy Statement. We also require our executive officers to hold a significant amount of our common stock (between 3 and 6 times the base salary) to further align their performance with the interest of our shareholders.

PERFORMANCE AGAINST TARGETS

In 2020, we successfully navigated the challenges resulting from the COVID-19 pandemic and achieved strong financial performance with an increase of 5.7 percent year-over-year in earnings per share, as adjusted. Earnings per share from ongoing operations, as adjusted is defined and reconciled to GAAP earnings per share in Appendix A. Performance against our incentive metrics are illustrated below. For an explanation of the short-term and long-term incentive metrics and payouts, please see "Executive Compensation - Compensation Discussion and Analysis" beginning on page 25 of the Proxy Statement.

Short-term Incentive

- Financial: 130% of target achieved (70% of the target incentive)
  Safety: 179% of TCIR target achieved (10% of the target incentive)
  0% of PMVI target achieved (10% of the target incentive)
  Wellness: 104% of target achieved (10% of the target incentive)
- Payout: 120% of target

**Long-term Incentive
(for the 2018-2020 Plan Period)**

- Financial: 112% of target achieved
- Payout: 112% of target

SHAREHOLDER FEEDBACK ON EXECUTIVE PAY

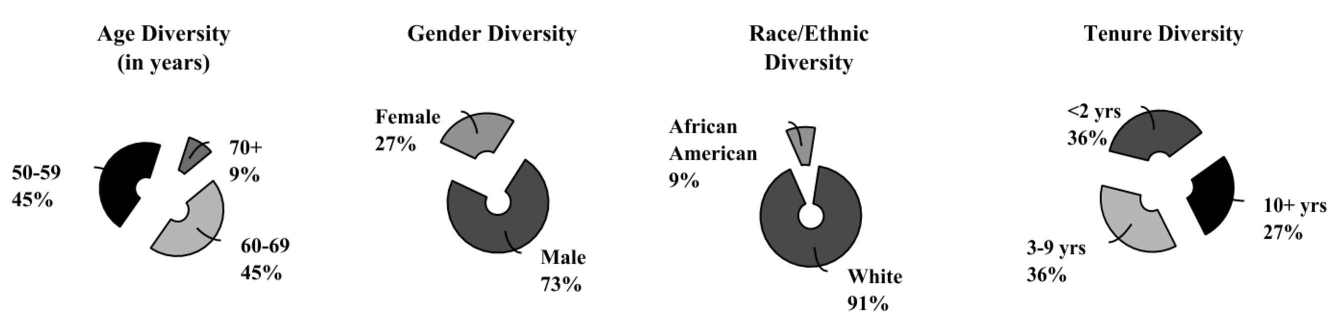
At our 2020 annual meeting, shareholders owning 97 percent of the shares voted approved our executive compensation for 2019. We believe this result is highly supportive of our executive pay program and our compensation philosophy. With the exception of the addition of the wellness metric as one of our short-term incentive metrics in 2020, our executive pay program is structured consistent with the parameters that our shareholders previously approved. We did not make any adjustments to our executive pay program as a result of the COVID-19 pandemic.

Corporate Governance

In 2020, shareholders owning 97 percent of the shares voted elected five of our current directors. Our Board of Directors also appointed two new directors last year, including one race/ethnic diverse director. As illustrated in the charts below, diverse board membership is a priority for us and our Board of Directors.

DIRECTOR DIVERSITY

Our Board of Directors have nominated five board members for election at our 2021 Annual Meeting of Shareholders. Each of the nominees is an independent director, with the exception of our CEO, and is identified in Proposal No. 1 – Election of Directors. Each candidate’s skills and experience are summarized beginning on page 7 of the Proxy Statement.

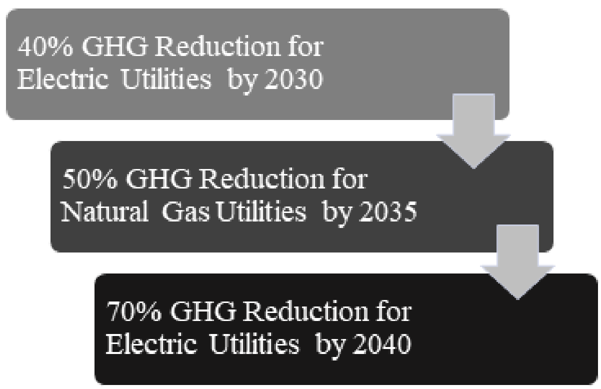


Sustainability Stewardship

Our mission of improving life with energy means we must be ready to make tomorrow even better than today. That is why we're committed to creating a cleaner energy future which builds upon our responsibility to provide the safe, reliable and economic energy that improves our customers' lives. By investing in the success of our employees, continually innovating, thoughtfully utilizing resources and keeping people at the core of our decision-making, we are dedicated to the sustainability of our company, communities and planet.

GHG REDUCTION GOALS

Throughout our history, we have been strong environmental stewards. We've pioneered new power plant technology, set the bar for lower emissions levels and built infrastructure ahead of current standards. We do more than talk, and as we look to the future, we know sharing our intentions and goals for improving the climate will help us achieve them. Our goal for our electric utilities is to reduce greenhouse gas emissions ("GHG") intensity 40% by 2030 and 70% by 2040 as compared to 2005. With respect to our natural gas utilities we have cut our emissions intensity by over 33% since 2005 and commit to achieving a 50% total reduction in our GHG emissions intensity by 2035 (as compared to 2005).



COLORADO CLEANEST FLEET

We operate the cleanest electric utility in Colorado, with an all-renewable and natural gas generation fleet. Our Colorado electric utility has achieved an approximate 50% reduction in GHG emissions since 2005 and is on track to reach 80% reduction by 2030.

CORPORATE SUSTAINABILITY REPORT

For additional information on our sustainability stewardship or to view our 2019 Corporate Sustainability Report, please visit our website at www.blackhillsenergy.com/our-company/sustainability.

BLACK HILLS CORPORATION

7001 Mount Rushmore Road
Rapid City, South Dakota 57702

PROXY STATEMENT

✓ A proxy in the accompanying form is solicited by the Board of Directors of Black Hills Corporation, a South Dakota corporation, to be voted at the annual meeting of our shareholders to be held Tuesday, April 27, 2021, and at any adjournment of the annual meeting.

✓ The enclosed form of proxy, when executed and returned, will be voted as set forth in the proxy. Any shareholder signing a proxy has the power to revoke the proxy in writing, addressed to our secretary, or in person at the meeting at any time before the proxy is exercised.

✓ We will bear all costs of the solicitation. In addition to solicitation by mail, our officers and employees may solicit proxies by telephone, fax, or in person. We have retained Georgeson LLC to assist us in the solicitation of proxies at an anticipated cost of $9,500.00, plus out-of-pocket expenses. Also, we will, upon request, reimburse brokers or other persons holding stock in their names or in the names of their nominees for reasonable expenses in forwarding proxies and proxy materials to the beneficial owners of stock.

✓ This proxy statement and the accompanying form of proxy are to be first mailed on or about March 18, 2021. Our 2020 annual report to shareholders is being mailed to shareholders with this proxy statement.

VOTING RIGHTS AND PRINCIPAL HOLDERS

✓ Only our shareholders of record at the close of business on March 8, 2021 are entitled to vote at the meeting. Our outstanding voting stock as of the record date consisted of 62,871,886 shares of our common stock.

✓ Each outstanding share of our common stock is entitled to one vote. Cumulative voting is permitted in the election of directors in the same class.

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COMMONLY ASKED QUESTIONS AND ANSWERS ABOUT THE ANNUAL MEETING PROCESS

Who is soliciting my proxy?

The Board of Directors of Black Hills Corporation is soliciting your proxy.

Where and when is the annual meeting?

The annual meeting is at 9:30 a.m., local time, April 27, 2021 at Horizon Point, the Company's corporate headquarters, 7001 Mount Rushmore Road, Rapid City, South Dakota.

Who can vote?

Holders of our common stock as of the close of business on the record date, March 8, 2021, can vote at our annual meeting. Each share of our common stock has one vote for Proposals 2 and 3. Related to Proposal 1, Election of Directors, cumulative voting is permitted in the election of directors in the same class.

How do I vote?

There are three ways to vote by proxy:

- by calling the toll free telephone number on the enclosed proxy;
- by using the Internet by going to the website identified on the enclosed proxy; or
- by returning the enclosed proxy in the envelope provided.

You *may* be able to vote by telephone or the Internet if your shares are held in the name of a bank or broker. If this is the case, you will need to follow their instructions.

What constitutes a quorum?

Shareholders representing at least 50 percent of our common stock issued and outstanding as of the record date must be present at the annual meeting, either in person or by proxy, for there to be a quorum. Abstentions and broker non-votes are counted as present for establishing a quorum. A broker non-vote occurs when a broker or other nominee holding shares for a beneficial owner does not vote on a particular proposal because the broker or nominee does not have discretionary voting power and has not received instructions from the beneficial owner.

What am I voting on and what is the required vote for the proposals to be adopted?

The required vote and method of counting votes for the various business matters to be considered at the annual meeting are described in the table below. If you sign and return your proxy card without indicating your vote, your shares will be voted in accordance with the Board recommendations as set forth below.

Item of Business	Board Recommendation	Voting Approval Standard	Effect of Abstention	Effect of Broker Non-Vote
Proposal 1: Election of Directors	FOR election of each director nominee	The five nominees with the most "FOR" votes are elected to their respective classes. If a nominee receives more "WITHHOLD AUTHORITY" votes than "FOR" votes, the nominee must submit a resignation for consideration by the Governance Committee and final Board decision.	No effect	No effect
Proposal 2: Ratification of Appointment of Independent Registered Public Accounting Firm	FOR	The majority of votes present in person or represented by proxy and entitled to vote.	No effect	Not applicable; broker may vote shares without instruction
Proposal 3: Advisory Vote to Approve Executive Compensation	FOR	The majority of votes present in person or represented by proxy and entitled to vote. This advisory vote is not binding on the Board, but the Board will consider the vote results when making future executive compensation decisions.	No effect	No effect

Is cumulative voting permitted for the election of directors?

In the election of directors, you may cumulate your vote. Cumulative voting allows you to allocate among the director nominees in the same class, as you see fit, the total number of votes equal to the number of director positions to be filled multiplied by the number of shares you hold. For example, if you own 100 shares of stock, and there are three directors to be elected in a class at the annual meeting, you could allocate 300 "For" votes (three times 100) among as few or as many of the three nominees to be voted on at the annual meeting as you choose.

If you choose to cumulate your votes, you will need to submit a proxy card or a ballot and make an explicit statement of your intent to cumulate your votes, either by indicating in writing on the proxy card or by indicating in writing on your ballot when voting at the annual meeting. If you hold shares beneficially in street name and wish to cumulate votes, you should contact your broker, trustee or nominee.

How will my shares be voted if they are held in a broker's name?

If you hold your shares through an account with a bank or broker, the bank or broker may vote your shares on some matters even if you do not provide voting instructions. Brokerage firms have the authority under the New York Stock Exchange ("NYSE") rules to vote shares on certain matters (such as the ratification of auditors) when their customers do not provide voting instructions. However, on most other matters when the brokerage firm has not received voting instructions from its customers, the brokerage firm cannot vote the shares on that matter and a "broker non-vote" occurs. **This means that brokers may not vote your shares on the election of directors or on the "say on pay" advisory vote if you have not given your broker specific instructions as to how to vote. Please be sure to give specific voting instructions to your broker so that your vote can be counted.**

What should I do now?

You should vote your shares by telephone, by the Internet or by returning your signed and dated proxy card in the enclosed envelope as soon as possible so that your shares will be represented at the annual meeting.

Who will count the vote?

Representatives of our transfer agent, Equiniti Trust Company, will count the votes and serve as judges of the election.

Who conducts the proxy solicitation and how much will it cost?

We are asking for your proxy for the annual meeting and will pay all the costs of asking for shareholder proxies. We have hired Georgeson LLC to help us send out the proxy materials and ask for proxies. Georgeson LLC's fee for these services is anticipated to be $9,500.00 plus out-of-pocket expenses. We can ask for proxies through the mail or by telephone, fax, or in person. We can use our directors, officers and employees to ask for proxies. These people do not receive additional compensation for these services. We will reimburse brokers and other custodians, nominees and fiduciaries for their reasonable out-of-pocket expenses for forwarding solicitation material to the beneficial owners of our common stock.

Can I revoke my proxy?

Yes. You can change your vote in one of four ways at any time before your proxy is used. First, you can enter a new vote by telephone or Internet. Second, you can revoke your proxy by written notice. Third, you can send a later dated proxy changing your vote. Fourth, you can attend the meeting and vote in person.

Who should I call with questions?

If you have questions about the annual meeting, you should call Amy K. Koenig, Vice President - Governance, Corporate Secretary and Deputy General Counsel at (605) 721-1700.

When are the shareholder proposals due for the 2022 annual meeting?

In order to be considered for inclusion in our proxy materials, you must submit proposals for next year's annual meeting in writing to our Corporate Secretary at our corporate headquarters at 7001 Mount Rushmore Road, P.O. Box 1400, Rapid City, South Dakota 57709, on or prior to November 18, 2021.

A shareholder who intends to submit a proposal for consideration, but not for inclusion in our proxy materials, must provide written notice to our Corporate Secretary in accordance with Article I, Section 9 of our Bylaws. In general, our Bylaws provide that the written notice must be delivered not less than 90 days nor more than 120 days prior to the first anniversary date of the immediately preceding annual meeting of shareholders. Our 2021 annual meeting is scheduled for April 27, 2021. Ninety days prior to the first anniversary of this date will be January 27, 2022, and 120 days prior to the first anniversary of this date will be December 28, 2021.

PROPOSAL 1	ELECTION OF DIRECTORS

Our Board is nominating five individuals for election as directors at this annual meeting. All of the nominees are currently serving as our directors. In accordance with our Bylaws and Article VI of our Articles of Incorporation, members of our Board of Directors are elected to three classes of staggered terms consisting of three years each, and until their successors are duly elected and qualified. At this annual meeting, one director will be elected to Class II for a term of two years until our annual meeting in 2023, and four directors will be elected to Class III for a term of three years until our annual meeting in 2024.

Nominees for director at the annual meeting are Linden R. Evans, Barry M. Granger, Tony A. Jensen, Steven R. Mills, and Scott M. Prochazka. Our Bylaws require a minimum of nine directors. The Board has set the size of the Board at 11 directors effective at the annual meeting in connection with one director retirement occurring at that time.

Pursuant to our Bylaws, directors must resign from the Board at the annual meeting following attaining 72 years of age. Accordingly, Mr. Madison, who turned 72 in 2020, will resign effective at this annual meeting. Additionally, we expect Mr. Vering, who will turn 72 prior to our 2022 annual meeting, will resign effective at our 2022 annual meeting and therefore serve only two years of his term.

If, at the time of the annual meeting, any of such nominees are unable to stand for election, the Board of Directors may designate a substitute or reduce the number of directors to no less than nine. In that case, shares represented by proxies may be voted for a substitute director nominated by the Board. We do not expect that any nominee will be unavailable or unable to serve.

The Board and the Governance Committee believe that the combination of the various qualifications, skills and experiences of the directors contribute to an effective and well-functioning Board, and that, individually and as a whole, the directors possess the necessary qualifications to provide effective oversight of the business and quality advice to the Company’s management. Included in each director’s biography below is an assessment of the specific qualifications, attributes, skills and experience that have led to the conclusion that each individual should serve as a director in light of our current business and structure.

The Board of Directors recommends a vote *FOR* the election of the following nominees:

Director Nominee	Class	Year Term Expiring
Linden R. Evans	III	2024
Barry M. Granger	III	2024
Tony A. Jensen	III	2024
Steven R. Mills	III	2024
Scott M. Prochazka	II	2023

Linden R. Evans

President and Chief Executive Officer of the Company

Director since: 2018

Director Nominee Class: III, term expiring in 2024

Age: 58

Outside Directorships:

None

Summary:

On January 1, 2019, Mr. Evans succeeded David R. Emery and became President and Chief Executive Officer of the Company. He previously served as President and Chief Operating Officer from 2016 to 2018, and President and Chief Operating Officer – Utilities from 2004 to 2015. He began his career with Black Hills Corporation in 2001 as Corporate Counsel. Prior to joining the Company, Mr. Evans was a mining engineer and an attorney specializing in environmental and corporate legal matters.

Skills and Qualifications:

strategic leadership, utility management, operations, risk oversight, environmental, safety, customer perspective,

Barry M. Granger

Managing Partner and Co-Founder of B3 Technology Investments

Director since: 2020

Director Nominee Class: III, term expiring in 2024

Age: 61

Standing Board Committees:

None

Outside Directorships:

None

Summary:

Mr. Granger has been leading B3 Technology Investments, a start-up Private Equity firm, for the past three years. Prior to this role, Mr. Granger had a 35-year career at the DuPont and Dow Chemical Companies. He was the Vice President of Government Marketing and Government Affairs from 2010 to 2017, and the Vice President and General Manager, Tyvek®, from 2007-2010. Early in his career, he was selected to be Executive Assistant to the Chairman, President and CEO of DuPont. He also held a variety of leadership positions with increasing responsibility in manufacturing, product management, operations, sales, and marketing.

Skills and Qualifications:

strategic leadership, financial acumen, risk oversight, corporate governance, operations, regulatory, environmental, PROXY

Tony A. Jensen

Retired Director, President and Chief Executive Officer, Royal Gold, Inc.

Director since: 2019

Director Nominee Class: III, term expiring in 2024

Age: 58

Standing Board Committees:
Compensation Committee

Outside Directorships:
None

Summary:

Mr. Jensen has over 35 years of experience in the mining and mining finance industries. From 2003 until his retirement in 2019, Mr. Jensen served in several leadership roles at Royal Gold, Inc., a public precious metals company, including Director, President and Chief Executive Officer from 2006 to 2019, and Chief Operating Officer from 2003 to 2006. Prior to 2003, he held progressively more responsible roles in engineering, finance, strategic growth, safety, environmental excellence, and operational efficiency.

Skills and Qualifications:

strategic leadership, financial acumen, risk oversight, mergers and acquisitions, operations, environmental, safety, human resources, executive compensation

Kathleen S. McAllister

Retired Director, President and Chief Executive Officer, Transocean Partners LLC

Director since: 2019

Director Class: I, term expiring in 2022

Age: 56

Standing Board Committees:
Audit Committee

Outside Directorships:
Hoegh LNG Partners LP (since 2017)
Maersk Drilling (since 2019)

Summary:

Ms. McAllister has over 30 years of experience with diverse leadership roles in global, capital intensive companies in the energy value chain. She served as Director, President and Chief Executive Officer from 2014 to 2016 and as Chief Financial Officer in 2016 of Transocean Partners LLC, an international provider of offshore contract drilling services for oil and gas wells. She held the roles of Vice President and Treasurer from 2011 to 2014 of Transocean Ltd. Prior to 2011, she served in roles with increasing responsibility in finance, information technology, tax and treasury. Ms. McAllister is a Board Member of Hoegh LNG Partners and Maersk Drilling, where she serves as the Chair of the Audit and Risk Committee.

Skills and Qualifications:

strategic leadership, financial acumen, risk oversight, operations, technology systems, environmental, safety, raising capital, capital allocation, governance

Steven R. Mills

Chairman of the Board
Retired Public Company Financial Executive

Director since: 2011

Director Nominee Class: III, term expiring in 2024

Age: 65

Standing Board Committees:
Audit Committee
Governance Committee

Outside Directorships:

Amyris, Inc. (since 2018)

Summary:

Mr. Mills has more than 40 years of experience in the fields of accounting, corporate finance, strategic planning, risk management, and mergers and acquisitions. He is a member of the Board of Directors of Amyris, Inc., a renewable products company, where he serves as Chair of the Audit Committee, Chair of the Operations and Finance Committees and as a member of the Leadership Development and Compensation Committee. Mr. Mills also serves on the boards of other private companies and is a consultant and advisor to Arianna S.A., a European-based specialized investment fund. Previously, Mr. Mills served as Chief Financial Officer of Amyris, Inc. from 2012 to 2013. Prior to joining Amyris, he had a 33-year career at Archer Daniels Midland Company, one of the world's largest agricultural processors and food ingredient providers, where he held various senior executive roles, including Senior Executive Vice President Performance and Growth, Chief Financial Officer, Controller, and Senior Vice President Strategic Planning.

Skills and Qualifications:

strategic leadership, financial acumen, risk oversight, mergers and acquisitions

Robert P. Otto

Owner, Bob Otto Consulting LLC

Director since: 2017

Director Class: I, term expiring in 2022

Age: 61

Standing Board Committees:
Audit Committee

Outside Directorships:

None

Summary:

Since 2017, Mr. Otto has been providing strategic planning and services in cyber security, intelligence and reconnaissance. He retired from the U.S. Air Force in 2016 as a lieutenant general. He served as general officer since 2008, with his career culminating as the Air Force Deputy Chief of Staff for Intelligence, Surveillance and Reconnaissance. As the Air Force's senior most intelligence officer, he was directly responsible for policy planning, evaluation, oversight, and leadership of a workforce of 27,000.

Skills and Qualifications:

strategic leadership, financial acumen, risk oversight, technology systems/cyber security

Scott M. Prochazka

Former Board Member, President and Chief Executive Officer of CenterPoint Energy

Director since: 2020

Director Nominee Class: II, term expiring in 2023

Age: 55

Standing Board Committees:

None

Outside Directorships:

Peridot Acquisition Corporation (since August 2020)

Summary:

Mr. Prochazka served as Board Member, President and Chief Executive Officer of CenterPoint Energy, a public energy delivery company with electric transmission and distribution, power generation and natural gas distribution operations, from 2014 until his retirement in 2020. Prior to that he was Chief Operating Officer from 2012 – 2013, Senior Vice President Electric Business from 2011 to 2012, and Vice President Gas Business Unit from 2009 to 2011. He held other management positions including Vice President Customer Care and Support Services and Vice President Texas Gas Region. Before his time at CenterPoint Energy and Enable Midstream, Mr. Prochazka held roles of increasing responsibility at Dow Chemical. Mr. Prochazka was a Board Member of Enable Midstream Partners, LP, from 2014 through 2020, and Chairman from 2015 through 2017. Mr. Prochazka was recently appointed to the Board of Directors of Peridot Acquisition Corporation where he serves on the Audit and Compensation Committees.

Skills and Qualifications:

strategic leadership, utility management, financial acumen, operations, risk oversight, regulatory, safety, customer perspective, human resources, executive compensation

Rebecca B. Roberts

Retired President, Chevron Pipe Line Company

Director since: 2011

Director Class: II, term expiring in 2023

Age: 68

Standing Board Committees:

Compensation Committee
Governance Committee (Chair)

Outside Directorships:

AbbVie, Inc. (since 2018)
MSA Safety, Inc. (since 2013)

Summary:

Ms. Roberts has over 35 years of experience in the energy industry, including managing pipelines in North America and global pipeline projects, and managing a portfolio of power plants in the United States, Asia, and the Middle East. From 2006 until her retirement in 2011, Ms. Roberts served as the President of Chevron Pipe Line Company, a pipeline company transporting crude oil, refined petroleum products, liquefied petroleum gas, natural gas, and chemicals within the United States. From 2003 until 2006, she was the President of Chevron Global Power Generation. She has also served on the board of Enbridge, Inc., from 2015 to 2018. Ms. Roberts is a member of the Board of Directors of Abbvie, Inc. and MSA Safety, Inc., where she serves as the Chair of the Compensation Committee.

Skills and Qualifications:

strategic leadership, risk oversight, operations, financial acumen, environmental, safety, human resources, executive compensation

Mark A. Schober

Retired Senior Vice President and Chief Financial Officer, ALLETE, Inc.

Director since: 2015

Director Class: I, term expiring in 2022

Age: 65

Standing Board Committees:

Audit Committee (Chair)

Outside Directorships:

None

Summary:

Mr. Schober has more than 35 years of experience in the utility and energy industry. Beginning in 2006 and concluding with his retirement in 2014, Mr. Schober served as the Senior Vice President and Chief Financial Officer of ALLETE, Inc. His extensive industry experience in the portion of the country in which he worked provides expertise in the regulated business model and the unique challenges of the geographic and regulatory environment in which we operate.

Skills and Qualifications:

strategic leadership, financial acumen, risk oversight, regulatory, utility management

Teresa A. Taylor

Chief Executive Officer of Blue Valley Advisors, LLC

Director since: 2016

Director Class: II, term expiring in 2023

Age: 57

Standing Board Committees:

Compensation Committee (Chair)

Outside Directorships:

T-Mobile USA, Inc. (since 2013)

Summary:

Ms. Taylor has over 30 years of experience in technology, media, and the telecom sectors. She has been the Chief Executive Officer of Blue Valley Advisors, LLC, a consulting firm that she founded, since 2011. She was the Chief Operating Officer of Qwest Communications, Inc., a telecommunications carrier, from 2009 to 2011, where she led the daily operations and a senior management team responsible for 30,000 employees in field support, technical development, sales, marketing, customer support and information technology systems. She is a member of the Board of Directors of T-Mobile USA, Inc. She previously served on the Board of NiSource, a public utility company from 2012 to 2015, Columbia Pipeline Group, Inc. from 2015 to 2016, and First Interstate BancSystem, Inc. from 2012 to 2020.

Skills and Qualifications:

strategic leadership, operations, risk oversight, customer perspective, human resources, executive compensation, technology systems/cyber security

John B. Vering

Partner Vering Feed Yards LLC
Retired Managing Director,
Lone Mountain Investments, Inc.

Director since: 2005

Director Class: II, term expiring in 2023

Age: 71

Standing Board Committees:

Audit Committee
Governance Committee

Outside Directorships:

None

Summary:

Mr. Vering has over 30 years of experience in the oil and gas industry, including direct operating experience in oil and gas transportation and marketing. From 2002 until his retirement in 2019, Mr. Vering was the Managing Director of Lone Mountain Investments, Inc., an oil and gas investment firm. Prior to this role, Mr. Vering had a 23-year career with Union Pacific Resource Company in several positions of increasing responsibilities including Vice President of Canadian Operations. Mr. Vering has been a partner in Vering Feed Yards, LLC, a privately-owned agricultural company, since 2010.

Skills and Qualifications:

strategic leadership, financial acumen, risk oversight, operations, environmental, safety

CORPORATE GOVERNANCE

Corporate Governance Guidelines

Our Board of Directors has adopted “Corporate Governance Guidelines of the Board of Directors,” which guide the operation of our Board and assist the Board in fulfilling its obligations to shareholders and other constituencies. The guidelines lay the foundation for the Board’s responsibilities, operations, leadership, organization and committee matters. The Governance Committee reviews the guidelines annually, and the guidelines may be amended at any time, upon recommendation by the Governance Committee and approval of the Board. These guidelines can be found in the “Governance” section of our website (www.blackhillscorp.com/investor-relations/corporate-governance).

Board Leadership Structure

Following the May 1, 2020 retirement of our former Executive Board Chairman David R. Emery, Steven R. Mills, an independent director, was appointed Chairman of the Board. As Chairman, Mr. Mills leads our Board in the performance of its duties by working with the CEO to establish meeting agendas, facilitating board meetings and executive sessions, and collaborating with the Board to annually evaluate the performance of the CEO.

As provided in our Corporate Governance Guidelines, the Board does not have a policy on whether or not the roles of Chairman and CEO should be separate or combined. The Governance Committee annually reviews the appropriate leadership structure for the Company and recommends a Chairman for Board approval. While our bylaws and Corporate Governance Guidelines do not require that our Chairman and CEO positions be separate, the Board of Directors believes that having separate positions and having an independent director serve as Chairman is the appropriate leadership structure for the Company at this time.

Risk Oversight

Our Board oversees an enterprise risk management (“ERM”) approach to risk management that supports our operational and strategic objectives. It fulfills its oversight responsibilities through receipt of quarterly reports from management regarding material risks involving strategic planning and execution, operations, physical and cyber security, environmental, social and governance (“ESG”), financial, legal, safety, regulatory, and human resources risks. While our full Board retains responsibility for risk oversight, it delegates oversight of certain risk considerations to its committees within each of their respective areas of responsibility as defined in the charter for each committee.

Our management is responsible for day-to-day risk management and operates under our ERM program that addresses enterprise risks. The ERM program includes practices to identify risks, assesses the impact and likelihood of occurrence, and develops action plans to prevent the occurrence or mitigate the impact of the risk. The ERM program includes regular reporting to our senior management team, quarterly reporting to our Board of Directors, and includes monitoring and testing by the Risk Management, Compliance and Internal Audit groups.

Sustainability Oversight

We are committed to creating a cleaner energy future which builds upon our responsibility to provide the safe, reliable and economic energy that improves our customers' lives. The Board oversees management's execution of our sustainability objectives and regularly receives updates from management regarding sustainability matters. Under the oversight of the Board, in the fourth quarter of 2020, the Company published its 2019 Corporate Sustainability Report and announced its greenhouse gas emissions intensity reduction goals of 40% by 2030 and 70% by 2040 for our electric utilities and 50% by 2035 for our natural gas utilities (as compared to 2005).

Cyber and Physical Security Oversight

Our Board retains oversight of cyber and physical security. Our Chief Information Officer provides the Board quarterly reports that summarize material security risks and the measures that have been put in place to mitigate the associated risks. These reports address a variety of topics including updates on strategic initiatives, industry trends, threat vulnerability assessments, and efforts to prevent, detect and respond to internal and external critical threats.

Human Capital Management Oversight

Primary responsibility for oversight of human capital management rests with our Compensation Committee. In the furtherance of this responsibility, the Committee reviews regular reports from management regarding diversity and inclusion, pay equity, strategic workforce planning, talent retention, employee benefits programs, and employee engagement.

Succession Planning Oversight

Our Board is actively engaged in succession planning for our key executive positions. To assist the Board, our CEO and our Senior Vice President - Chief Human Resources Officer perform talent reviews and discuss succession planning and leadership development. Semi-annually, their assessment of senior executive talent, including potential of such talent to succeed our CEO or other executive officers, readiness for succession and development opportunities are presented to our Board.

Director Nominees

The Governance Committee uses a variety of methods for identifying and evaluating nominees for director. The Governance Committee regularly assesses the appropriate size of the Board and whether any vacancies on the Board are expected due to retirement or otherwise. In the event vacancies are anticipated, or otherwise arise, the Governance Committee considers various potential candidates for director. Board candidates are considered based upon various criteria, including diversity; business, administrative and professional skills or experiences; an understanding of relevant industries, technologies and markets; financial literacy; independence status; the ability and willingness to contribute time and special competence to Board activities; personal integrity and independent judgment; and a commitment to enhancing shareholder value. The Governance Committee considers these and other factors as it deems appropriate, given the needs of the Board. Our goal is a diverse, talented, and highly engaged Board, with members whose skills, background and experience are complementary and, together, cover the spectrum of areas that impact our business currently and in the future. The Governance Committee considers candidates for Board membership suggested by a variety of sources, including current or past Board members, the use of third-party executive search firms, members of management and shareholders. Any shareholder may make recommendations for consideration by the Governance Committee for membership on the Board by sending a written statement of the qualifications of the recommended individual to the Corporate Secretary. There are no differences in the manner by which the Committee evaluates director candidates recommended by shareholders from those recommended by other sources.

Messrs. Granger and Prochazka are standing for election by shareholders for the first time at this annual meeting. Mr. Granger was identified as a candidate by an existing non-employee board member and Mr. Prochazka was identified as a candidate by a third-party search firm. The firm was engaged to assist in the identification and assessment of director candidates, including assessment of Messrs. Granger and Prochazka, based on criteria developed by the Governance Committee.

Shareholders who intend to nominate persons for election to the Board of Directors must provide timely written notice of the nomination in accordance with Article I, Section 9 of our Bylaws. Generally, our Corporate Secretary must receive the written notice at our executive offices at 7001 Mount Rushmore Road, P.O. Box 1400, Rapid City, South Dakota 57709, not less than 90 days nor more than 120 days prior to the anniversary date of the immediately preceding annual meeting of shareholders. For the 2022 shareholder meeting, those dates are January 27, 2022 and December 28, 2021. The notice must include at a minimum the information set forth in Article I, Section 9 of our Bylaws, including the shareholder's identity and status, contingent ownership interests, description of any agreement made with others acting in concert with respect to the nomination, specific information about the nominee and certain representations by the nominee to us.

Board Independence

In accordance with NYSE rules, the Board of Directors through its Governance Committee, affirmatively determines the independence of each director and director nominee in accordance with guidelines it has adopted, which include all elements of independence set forth in the NYSE listing standards. These guidelines are contained in our Policy for Director Independence, which can be found in the "Governance" section of our website (www.blackhillscorp.com/investor-relations/corporate-governance). Based on these standards, the Governance Committee determined that each of the following non-employee directors is independent and has no relationship with us, except as a director and shareholder: Barry M. Granger, Tony A. Jensen, Kathleen S. McAllister, Michael H. Madison, Steven R. Mills, Robert P. Otto, Scott M. Prochazka, Rebecca B. Roberts, Mark A. Schober, Teresa A. Taylor, and John B. Vering. In addition, based upon such standards, the Governance Committee determined that Mr. Evans is not independent because he is an Officer of the Company.

Director Resignation Policies

The Corporate Governance Guidelines require members of the Board to submit a letter of resignation for consideration by the Board in certain circumstances. The Guidelines include a plurality plus voting policy. Pursuant to the policy, any nominee for election as a director in an uncontested election who receives a greater number of votes "Withheld" from his or her election than votes "For" his or her election will promptly tender his or her resignation as a director to the Chairman of the Board following certification of the election results. Broker non-votes will not be deemed to be votes "For" or "Withheld" from a director's election for purposes of the policy. The Governance Committee (without the participation of the affected director) will consider each resignation tendered under the policy and recommend to the Board whether to accept or reject it. The Board will then take the appropriate action on each tendered resignation, taking into account the Governance Committee's recommendation. The Governance Committee in making its recommendation, and the Board in making its decision, may consider any factors or other information that it considers appropriate, including the reasons why the Governance Committee believes shareholders "Withheld" votes for election from such director and any other circumstances surrounding the "Withheld" votes, any alternatives for curing the underlying cause of the "Withheld" votes, the qualifications of the tendering director, his or her past and expected future contributions to us and the Board, and the overall composition of the Board, including whether accepting the resignation would cause us to fail to meet any applicable SEC or NYSE requirements. The Board will publicly disclose by filing with the SEC on Form 8-K its decision and, if applicable, its rationale within 90 days after receipt of the tendered resignation.

The Corporate Governance Guidelines also require members of the Board to tender a letter of resignation in the event of a change in professional responsibilities that may directly or indirectly impact that board member's ability to fulfill directorship obligations. The Board is not obligated to accept such resignation. The Governance Committee will review the affected member's service and qualifications and recommend to the Board the continued appropriateness of Board membership under the circumstances.

Code of Business Conduct and Ethics

The Code of Business Conduct and the Code of Ethics that applies to our Chief Executive Officer, Chief Financial Officer, Corporate Controller, and certain other persons performing similar functions can be found in the "Governance" section of our website (www.blackhillscorp.com/investor-relations/corporate-governance). We intend to disclose any amendments to, or waivers of, the Code of Ethics on our website. Please note that none of the information contained on our website is incorporated by reference in this proxy statement.

Certain Relationships and Related Party Transactions

We recognize related party transactions can present potential or actual conflicts of interest and create the appearance that decisions are based on considerations other than the best interests of us and our shareholders. Accordingly, as a general matter, it is our preference to avoid related party transactions. Nevertheless, we recognize that there are situations where related party transactions may be in, or may not be inconsistent with, the best interests of us and our shareholders, including but not limited to situations where we may obtain products or services of a nature, quantity or quality, or on other terms, that are not readily available from alternative sources or when we provide products or services to related parties on an arm's length basis on terms comparable to those provided to unrelated third parties or on terms comparable to those provided to employees generally. Therefore, our Board of Directors has adopted a policy for the review of related party transactions. This policy requires directors and officers to promptly report to our General Counsel all proposed or existing transactions in which the Company and they, or persons related to them, are parties or participants. Our General Counsel presents to our Governance Committee those transactions that may require disclosure pursuant to Item 404 of Regulation S-K (typically, those transactions that exceed $120,000). Our Governance Committee reviews the material facts presented and either approves or disapproves entry into the transaction. In reviewing the transaction, the Governance Committee considers the following factors, among other factors it deems appropriate: (i) whether the transaction is on terms no less favorable than terms generally available to an unaffiliated third party under the same or similar circumstances; (ii) the extent of the related party's interest in the transaction; and (iii) the impact on a director's independence in the event the related party is a director, an immediate family member of a director or an entity in which a director is a partner, shareholder or executive officer. There were no reportable related party transactions in 2020.

Communications with the Board

Shareholders and others interested in communicating directly with the Chairman, with the independent directors as a group, or the Board of Directors may do so in writing to the Chairman, Black Hills Corporation, 7001 Mount Rushmore Road, P.O. Box 1400, Rapid City, South Dakota 57709.

MEETINGS AND COMMITTEES OF THE BOARD

THE BOARD OF DIRECTORS

Our Board of Directors held six meetings during 2020. Each regularly scheduled meeting of the Board includes an executive session of only independent directors. We encourage our directors to attend the annual shareholders' meeting. During 2020, each current director attended at least 75 percent of the combined total of Board meetings and Committee meetings on which the director served and all directors then serving virtually attended the 2020 annual meeting of shareholders.

COMMITTEES OF THE BOARD

Our Board has three standing committees to facilitate and assist the Board in the execution of its responsibilities. The committees are currently the Audit Committee, the Compensation Committee and the Governance Committee. Each committee operates under a charter, which is available on our website at www.blackhillscorp.com/investor-relations/corporate-governance and is also available in print to any shareholder who requests it. In addition, our Board creates special committees from time to time for specific purposes. Members of the committees are designated by our Board upon recommendation of the Governance Committee.

Audit Committee	Primary Responsibilities
9 Meetings in 2020 **Members:** **Mark A. Schober (Chair)** **Kathleen S. McAllister** **Steven R. Mills** **Robert P. Otto** **John B. Vering** **Independence:** **100%**	• Assist the Board in fulfilling its oversight responsibility to our shareholders relating to the quality and integrity of our accounting, auditing and financial reporting practices; • Oversee the integrity of our financial statements, financial reporting systems of internal controls and disclosure controls regarding finance, accounting and legal compliance; • Review areas of potential significant financial risk to us; • Review consolidated financial statements and disclosures; • Appoint an independent registered public accounting firm for ratification by our shareholders; • Monitor the independence and performance of our independent registered public accountants and internal auditing department; • Pre-approve all audit and non-audit services provided by our independent registered public accountants; • Review the scope and results of the annual audit, including reports and recommendations of our independent registered public accountants; • Review the internal audit plan results of internal audit work and our process for monitoring compliance with our Code of Business Conduct and other policies and practices established to ensure compliance with legal and regulatory requirements; and • Periodically meet, in private sessions, with our VP - Internal Audit, Chief Financial Officer, Chief Compliance Officer, other management, and our independent registered public accounting firm.
Committee Report: **Page 24 of this** **Proxy Statement**	In accordance with the rules of the NYSE, all of the members of the Audit Committee are financially literate. In addition, the Board determined that Ms. McAllister and Messrs. Mills, Schober and Vering have the requisite attributes of an "audit committee financial expert" as provided in regulations promulgated by the SEC, and that such attributes were acquired through relevant education and/or experience.

Compensation Committee	Primary Responsibilities
6 Meetings in 2020 **Members:** **Teresa A. Taylor (Chair)** **Tony A. Jensen** **Rebecca B. Roberts** **Michael H. Madison** **Independence:** **100%** **Committee Report:** **Page 38 of this Proxy Statement**	• Discharge the Board of Directors' responsibilities related to executive and director compensation philosophy, policies and programs; • Perform functions required of directors in the administration of all federal and state laws and regulations pertaining to executive employment and compensation; • Consider and recommend for approval by the Board all executive compensation programs including executive benefit programs and stock ownership plans; • Promote an executive compensation program that supports the overall objective of enhancing shareholder value; and • Provide oversight of Company diversity and inclusion. The Compensation Committee has authority under its charter to retain compensation consultants and other advisors as the Committee may deem appropriate in its sole discretion. The Committee engaged Willis Towers Watson (WTW), an independent consulting firm, to conduct an annual review of our 2020 total compensation program for executive officers. The Committee reviewed the independence of WTW and the individual representative of WTW who served as a consultant to the Committee, in accordance with the SEC and NYSE requirements and the specific factors that the requirements cite. The Compensation Committee concluded that WTW was independent and WTW's performance of services raised no conflict of interest. The Committee's conclusion was based in part on a report that WTW provided to the Committee intended to reveal any potential conflicts of interest and a schedule provided by management of the type and amount of non-executive compensation services provided by WTW to the Company. During 2020, the cost of these non-executive compensation services was less than $25,000. In September of 2020, the Compensation Committee engaged Meridian Compensation Partners, LLC (Meridian) to provide services as the Committee's new compensation consultant. Committee concluded that Meridian is also independent, and it's performance of services raises no conflict of interest.

Compensation Committee Interlocks. None of our executive officers serve as a member of a board of directors or compensation committee of any entity that has one or more executive officers who serve on our Board or on our Compensation Committee.

Governance Committee	Primary Responsibilities
4 Meetings in 2020 **Members:** **Rebecca B. Roberts (Chair)** **Michael H. Madison** **Steven R. Mills** **John B. Vering** **Independence:** **100%**	• Assess the size of the Board and qualifications for Board membership; • Identify and recommend prospective directors to the Board to fill vacancies; • Review and evaluate director nominations submitted by shareholders, including reviewing the qualifications and independence of shareholder nominees; • Consider and recommend existing Board members to be renominated at our annual meeting of shareholders; • Consider the resignation of an incumbent director who makes a principal occupation change (including retirement) or who receives a greater number of votes "Withheld" than votes "For" in an uncontested election of directors and recommend to the Board whether to accept or reject the resignation; • Establish and review guidelines for corporate governance; • Recommend to the Board for approval committee membership and chairs of the committees; • Recommend to the Board for approval a Chairman or an independent director to serve as a Lead Director; • Review the independence of each director and director nominee; • Administer an annual evaluation of the performance of the Board and each Committee and a biennial evaluation of each individual director; • Ensure that the Board oversees the evaluation and succession planning of management; and • Oversee the reporting framework the Company utilizes to track and monitor progress associated with ESG activities.

DIRECTOR FEES

Compensation to our non-employee directors consists of cash retainers for Board members, Committee members, the Board Chairman and Committee Chairs. In addition, the Board members receive common stock equivalents that are deferred until after they leave the Board. Dividend equivalents accrue on the common stock equivalents. We do not pay meeting fees.

In setting non-employee director compensation, the Compensation Committee recommends the form and amount of compensation to the Board of Directors, which makes the final determination. In considering and recommending the compensation of non-employee directors, the Compensation Committee considers such factors as it deems appropriate, including historical compensation information, level of compensation necessary to attract and retain non-employee directors meeting our desired qualifications and market data. In the review of director compensation in 2020, Meridian completed a market compensation review of our peer companies' director fees. Based on this review, the cash retainer for the Chairman and the Compensation and Governance Committee Chairs was increased effective January 1, 2021 to more closely align with the median director compensation for our peer utility companies. The fee structure for director fees in 2020 and the new fees effective January 1, 2021 are as follows:

	2020 Fees		Fees Effective January 1, 2021	
	Cash	Common Stock Equivalents	Cash	Common Stock Equivalents
Board Retainer	$85,000	$105,000	$85,000	$105,000
Board Chairman	$50,000		$100,000	
Lead Director Retainer				
Committee Chair Retainer				
Audit Committee	$15,000		$15,000	
Compensation Committee	$10,000		$12,500	
Governance Committee	$7,500		$10,000	
Committee Member Retainer				
Audit Committee	$10,000		$10,000	
Compensation Committee	$7,500		$7,500	
Governance Committee	$7,500		$7,500	

DIRECTOR COMPENSATION FOR 2020 AND COMMON STOCK EQUIVALENTS OUTSTANDING AS OF DECEMBER 31, 2020[1]

Name[2]	Fees Earned or Paid in Cash	Stock Awards[3]	Total	Number of Common Stock Equivalents Outstanding at December 31, 2020[4]
Barry M. Granger[5]	$21,250	$26,250	$47,500	290
Tony A. Jensen	$90,000	$105,000	$195,000	1,845
Michael H. Madison	$103,333	$105,000	$208,333	14,900
Kathleen A. McAllister	$91,667	$105,000	$196,667	1,845
Steven R. Mills	$144,167	$105,000	$249,167	16,335
Robert P. Otto	$95,000	$105,000	$200,000	6,320
Scott M. Prochazka[5]	$21,250	$26,250	$47,500	290
Rebecca B. Roberts	$107,500	$105,000	$212,500	17,420
Mark A. Schober	$110,000	$105,000	$215,000	8,560
Teresa A. Taylor	$99,167	$105,000	$204,167	6,824
John B. Vering	$102,500	$105,000	$207,500	30,729

(1) Our directors did not receive any stock option awards, non-equity incentive plan compensation, pension benefits or perquisites in 2020 and did not have any stock options outstanding at December 31, 2020.

(2) Mr. Evans, our President and CEO, is not included in this table because he is our employee and thus receives no compensation for his services as director. Mr. Evans' compensation received as an employee is shown in the Summary Compensation Table for our Named Executive Officers.

(3) Each non-employee director, with the exception of Messrs. Granger and Prochazka, received a quarterly award of common stock equivalents with a grant date fair value of $26,250 per quarter, equivalent to $105,000 per year. The grant date fair value of a common stock equivalent is the closing price of a share of our common stock on the grant date.

(4) The common stock equivalents are fully vested in that they are not subject to forfeiture; however, the shares are not issued until after the director ends his or her service on the Board. The common stock equivalents are payable in stock or cash or can be deferred further at the election of the director.

(5) Messrs. Granger and Prochazka became members of our Board effective October 1, 2020; consequently their fees earned and stock award fair values reflect a partial year of service.

DIRECTOR STOCK OWNERSHIP GUIDELINES

Each member of our Board of Directors is required to hold shares of common stock or common stock equivalents equal to five times the annual cash Board retainer. Currently, all of our directors have met the stock ownership guideline except for Messrs. Granger and Prochazka, who have been on the Board for less than a year.

SECURITY OWNERSHIP OF MANAGEMENT AND PRINCIPAL SHAREHOLDERS

The following table sets forth the beneficial ownership of our common stock as of February 25, 2021 for each director, each executive officer named in the Summary Compensation Table, all of our directors and executive officers as a group and each person or entity known by us to beneficially own more than five percent of our outstanding shares of common stock. Beneficial ownership includes shares a director or executive officer has or shares the power to vote or transfer. There were no stock options outstanding for any of our directors or executive officers as of February 25, 2021.

Except as otherwise indicated by footnote below, we believe that each individual or entity named has sole investment and voting power with respect to the shares of common stock indicated as beneficially owned by that individual or entity.

Name of Beneficial Owner(1)	Shares of Common Stock Beneficially Owned(2)	Directors Common Stock Equivalents(3)	Total	Percentage
Outside Directors				
Barry M. Granger	179	290	469	
Tony A. Jensen	6,460	1,845	8,305	*
Michael H. Madison	15,882	14,890	30,781	*
Kathleen S. McAllister	4,839	1,845	6,684	*
Steven R. Mills	18,127	16,335	34,462	*
Robert P. Otto	2,840	6,320	9,161	*
Scott M. Prochazka	179	290	469	
Rebecca B. Roberts	4,748	17,420	22,168	*
Mark A. Schober	4,283	8,560	12,843	*
Teresa A. Taylor	2,279	6,824	9,102	*
John B. Vering	11,058	30,729	41,787	*
Named Executive Officers				
Scott A. Buchholz	40,861	—	40,861	*
Linden R. Evans	138,360	—	138,360	*
Brian G. Iverson	34,049	—	34,049	*
Richard W. Kinzley	51,832	—	51,832	*
Stuart A. Wevik	28,050	—	28,050	*
All directors and executive officers as a group (18 persons)	385,718	105,359	491,078	*

* Represents less than one percent of the common stock outstanding.

(1) Beneficial ownership means the sole or shared power to vote, or to direct the voting of, a security or investment power with respect to a security.

(2) Includes restricted stock held by the following executive officers for which they have voting power but not investment power: Mr. Buchholz - 1,517 shares; Mr. Evans - 28,409 shares; Mr. Iverson - 6,631 shares; Mr. Kinzley - 8,469 shares; Mr. Wevik - 7,007 shares and all directors and executive officers as a group 60,964 shares.

(3) Represents common stock allocated to the directors' accounts in the directors' stock-based compensation plan, of which there are no voting rights.

PRINCIPAL SHAREHOLDERS

Set forth in the table below is information about the number of shares held by persons we know to be the beneficial owners of more than 5% of the issued and outstanding Common Stock.

Name and Address	Shares of Common Stock Beneficially Owned	Percentage
BlackRock, Inc.[(1)] 55 East 52nd Street New York, NY 10055	8,581,943	13.7
The Vanguard Group Inc.[(2)] 100 Vanguard Blvd. Malvern, PA 19355	6,576,633	10.5
State Street Corporation[(3)] State Street Financial Center One Lincoln Street Boston, MA 02111	5,538,442	8.8

(1) Information is as of December 31, 2020, and is based on a Schedule 13G/A filed on January 26, 2021. BlackRock, Inc. has sole voting power with respect to 8,478,431 shares and sole investment power with respect to 8,581,943 shares.

(2) Information is as of December 31, 2020, and is based on a Schedule 13G/A filed on February 10, 2021. The Vanguard Group Inc. has shared voting power with respect to 102,069 shares and sole investment power with respect to 6,425,255 shares.

(3) Information is as of December 31, 2020, and is based on a Schedule 13G filed on February 11, 2021. State Street Corporation has shared voting power with respect to 5,305,321 shares and shared investment power with respect to 5,538,442 shares.

PROPOSAL 2	RATIFICATION OF APPOINTMENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The firm of Deloitte & Touche LLP, independent registered public accountants, conducted the audit of Black Hills Corporation and its subsidiaries for 2020. Representatives of Deloitte & Touche LLP will be present at our annual meeting and will have the opportunity to make a statement, if they desire to do so, and to respond to appropriate questions.

Our Audit Committee has appointed Deloitte & Touche LLP to perform an audit of our consolidated financial statements and those of our subsidiaries for 2021 and to render their reports. In determining whether to recommend to the full Board the reappointment of Deloitte & Touche LLP as our independent auditor, the Audit Committee considered the following:

- Technical expertise and knowledge of the Company's business and industry
- The quality and candor of communications with the Audit Committee
- Deloitte & Touche LLP's independence
- Public Company Accounting Oversight Board inspection reports on the firm
- Input from management on Deloitte & Touche LLP's performance, objectivity and professional judgment
- The appropriateness of fees for audit and non-audit services

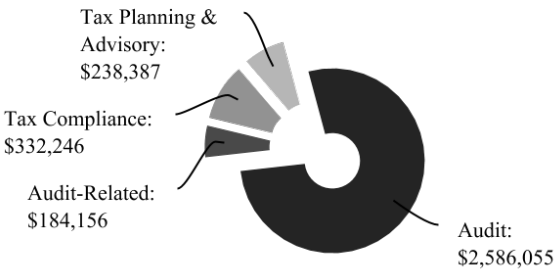
The Board of Directors recommends ratification of the Audit Committee's appointment of Deloitte & Touche LLP. The appointment of Deloitte & Touche LLP as our independent registered public accounting firm for 2021 will be ratified if the votes cast "For" exceed the votes cast "Against." Abstentions will have no effect on such vote. If shareholder approval for the appointment of Deloitte & Touche LLP is not obtained, the Audit Committee will reconsider the appointment.

The Board of Directors recommends a vote *FOR* ratification of the appointment of Deloitte & Touche LLP to serve as our independent registered public accounting firm for 2021.

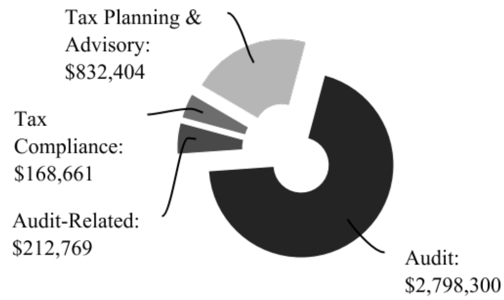
FEES PAID TO THE INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The following charts set forth the aggregate fees for services provided to us for the years ended December 31, 2020 and 2019 by our independent registered public accounting firm, Deloitte & Touche LLP:

2020 Deloitte & Touche LLP Fees
Total $3,340,844



2019 Deloitte & Touche LLP Fees
Total $4,012,134



Audit Fees

Fees for professional services rendered for the audits of our financial statements, review of the interim financial statements included in quarterly reports, opinions on the effectiveness of our internal control over financial reporting, and services that generally only the independent auditor can reasonably provide, such as comfort letters, statutory audits, consents and assistance with and review
of documents filed with the SEC.

Audit-Related Fees

Fees for assurance and related services that are reasonably related to the performance of the audit or review of our financial statements and are not reported under “Audit Fees.” These services include employee benefit plan audits.

Tax Compliance Fees

Fees for services related to federal and state tax compliance planning and advice and review of tax returns.

Tax Planning and Advisory Fees

Fees for planning and advisory services primarily related to partnership restructuring and jurisdictional simplification an consolidation related to prior acquisitions.

The services performed by Deloitte & Touche LLP were pre-approved in accordance with the Audit Committee’s pre-approval policy whereby the Audit Committee pre-approves all audit and permissible non-audit services provided by the independent registered public accountants. The Audit Committee will generally pre-approve a list of specific services and categories of services, including audit, audit-related, tax and other services, for the upcoming or current year, subject to a specified cost level. Any service that is not included in the approved list of services must be separately pre-approved by the Audit Committee.

AUDIT COMMITTEE REPORT

The Audit Committee assists the Board of Directors in fulfilling its oversight responsibilities to shareholders relating to the integrity of the Company's financial statements, the Company's compliance with legal and regulatory requirements regarding financial reporting, the independent auditors' qualifications and independence, and the performance of the Company's internal and independent auditors.

Management has the primary responsibility for the completeness and accuracy of the Company's financial statements and disclosures, the financial reporting process, and the effectiveness of the Company's internal control over financial reporting.

Our independent auditors, Deloitte & Touche LLP, are responsible for auditing the Company's consolidated financial statements and expressing an opinion as to whether they are presented fairly, in all material respects, in conformity with accounting principles generally accepted in the United States.

In fulfilling its oversight responsibilities for 2020, the Audit Committee, among other things:

- Reviewed and discussed the audited financial information contained in the Annual Report on Form 10-K with management and our independent auditors prior to public release.
- Reviewed and discussed with our independent auditors their judgments as to the quality, not just the acceptability, of our critical accounting principles and estimates and all other communications required to be discussed with the Audit Committee under generally accepted auditing standards, including the matters required to be discussed by the applicable requirements of the Public Company Accounting Oversight Board and the SEC.
- Reviewed and discussed with management, our internal auditors and our independent auditors management's report on internal control over financial reporting, including the significance and status of control deficiencies identified by management and the results of remediation efforts undertaken, to determine the effectiveness of internal control over financial reporting at December 31, 2020.
- Reviewed with our independent auditors their report on the Company's internal control over financial reporting at December 31, 2020, including the basis for their conclusions.
- Reviewed and pre-approved all audit and non-audit services and fees provided to the Company by our independent auditors and considered whether the provision of such non-audit services by our independent auditors is compatible with maintaining their independence.
- Discussed with our internal and independent auditors their audit plans, audit scope and identification of audit risks and reviewed the results of internal audit examinations.
- Reviewed and discussed the interim financial information contained in each quarterly earnings announcement and Quarterly Report on Form 10-Q with management and our independent auditors prior to public release.
- Received and reviewed periodic corporate compliance and financial risk reports, including credit and hedging activity.
- Held private sessions with our independent auditors, Vice President - Internal Audit, Chief Financial Officer and Controller, and Chief Compliance Officer.
- Received the written disclosures and the letter from our independent auditors required by the applicable requirements of the Public Company Accounting Oversight Board regarding the independent auditors' communications with the Committee concerning independence and discussed the independence of Deloitte & Touche LLP with them.
- Concluded Deloitte & Touche LLP is independent based upon the above considerations.

Based upon the reviews and discussions referred to above, the Audit Committee recommended to the Board that our audited consolidated financial statements be included in our Annual Report on Form 10-K for the year ended December 31, 2020 filed with the SEC. The Audit Committee also recommended and the Board reappointed Deloitte & Touche LLP as our independent registered public accounting firm for 2021. Shareholders are being asked to ratify that selection at the 2021 Annual Meeting.

THE AUDIT COMMITTEE

Mark A. Schober, Chair
Steven R. Mills
John B. Vering
Kathleen S. McAllister
Robert P. Otto

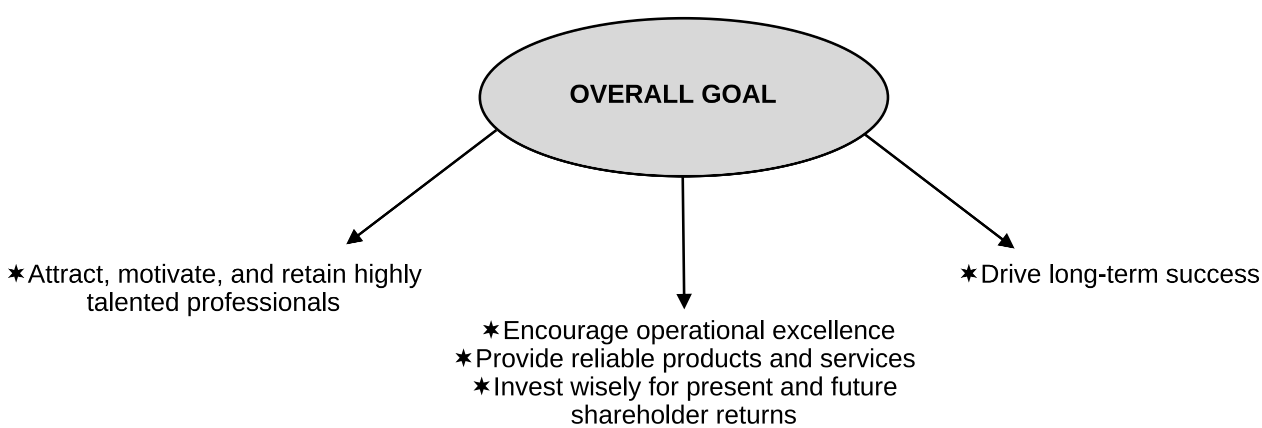
COMPENSATION DISCUSSION AND ANALYSIS

INTRODUCTION

This Compensation Discussion and Analysis describes our overall executive compensation policies and practices and specifically explains the compensation-related actions taken with respect to 2020 compensation for our Named Executive Officers included in the Summary Compensation Table. We did not make any modifications to our executive pay program as a result of the COVID-19 pandemic. Our Named Executive Officers, based on 2020 positions and compensation levels, are:

Named Executive Officers	Title	Reference
Linden R. Evans	President and Chief Executive Officer	Evans, CEO
Richard W. Kinzley	Sr. Vice President and Chief Financial Officer	Kinzley, CFO
Brian G. Iverson	Sr. Vice President, General Counsel and Chief Compliance Officer	Iverson, GC
Stuart A. Wevik	Sr. Vice President - Utility Operations	Wevik, UOO
Scott A. Buchholz	Sr. Vice President - Strategic Initiatives	Buchholz, SIO

The Compensation Committee of the Board of Directors (the “Committee,” for purposes of this Compensation Discussion and Analysis) is composed entirely of independent directors and is responsible for approving and overseeing our executive compensation philosophy, policies and programs.



EXECUTIVE COMPENSATION PROGRAM DESIGN OBJECTIVES				
✶	✶	✶	✶	✶
Attract, retain, motivate, and encourage the development of highly qualified executives	Provide competitive compensation	Promote the relationship between pay and performance	Promote corporate performance that is linked to our shareholders’ interests	Recognize and reward individual performance

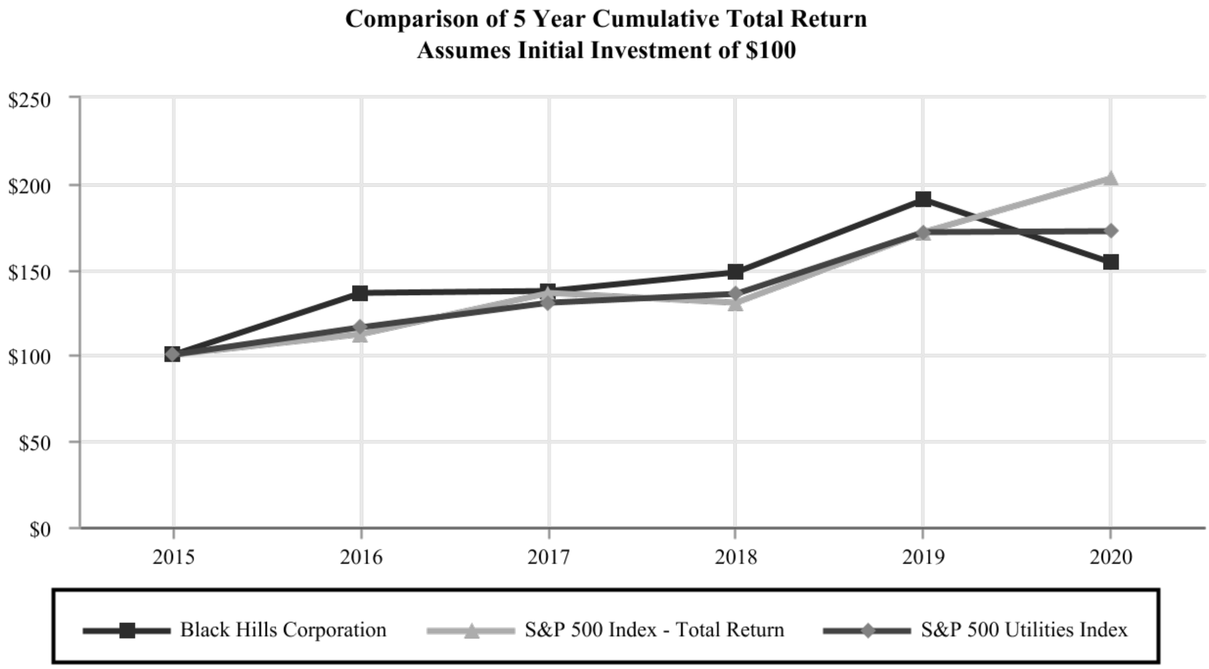
2020 ACCOMPLISHMENTS

Black Hills Corporation reported strong operational and financial performance in 2020. We successfully navigated the challenges in 2020 that resulted from the COVID-19 pandemic and executed well on our strategic initiatives. Significant accomplishments for the year included:

- Increased EPS, as adjusted, by 5.7 percent
- Completed significant financing activity, to accomplish our long-term objective of investing to meet the needs of our customers, including:
    - Issued $400 million of 2.50 percent 10-year senior notes due 2030
    - Issued 1.2 million shares of new common stock for net proceeds of $99 million through an underwritten registered transaction
- Named an independent Chairman of the Board
- Appointed two new members to our Board of Directors, including one racially diverse member
- Received support from 75.6 percent of the citizens in Pueblo, Colorado, to retain Colorado Electric as its electric utility provider
- Invested in our utility infrastructure and systems:
    - Deployed $755 million in capital projects
    - Placed in service the 52.5 megawatts Corriedale Wind Energy Project
- Executed a number of regulatory accomplishments:
    - Successfully completed a rate review request, including state-wide rate consolidation for Nebraska Gas
    - Received regulatory approval to add 200 megawatts of renewable solar energy in Colorado by year-end 2023 under our Renewable Advantage Program
    - Received approval from the Federal Energy Regulatory Commission of a power purchase agreement to continue serving Wyoming Electric with 60 megawatts of capacity and energy from the Wygen I power plant owned by Black Hills Wyoming
- Provided the safe and reliable service our communities and customers depend on and achieved several notable operations performance metrics:
    - Achieved industry leading reliability ranking by our three electric utilities compared to industry averages
    - Achieved first quartile safety performance total case incident rate of 1.0 compared to an industry average of 2.2
    - Achieved a safety performance preventable motor vehicle incident rate of 2.87 compared to a 2019 American Gas Association reported second quartile average of 2.61
    - Achieved an 8 percent Net Promotor Score improvement over 2019
    - Recognized as a “Gold Leader” in Colorado for achieving significant goals in environmental improvement and sustainability
    - Received the National Wild Turkey Federation's Energy for Wildlife National Achievement Award for our conservation efforts

RETURN TO SHAREHOLDERS

The following chart shows how a $100 investment in the Company's common stock on December 31, 2015 would have grown to $154.08 on December 31, 2020, with dividends reinvested. The chart also compares the total shareholder return on the Company's common stock to the same investment in the S&P 500 Index and S&P 500 Utilities Index over the same period.



2020 PERFORMANCE RESULTS

Our corporate financial, safety and wellness performance goals are used as measures to determine awards under our variable pay programs. The following table summarizes our 2020 performance measures and results.

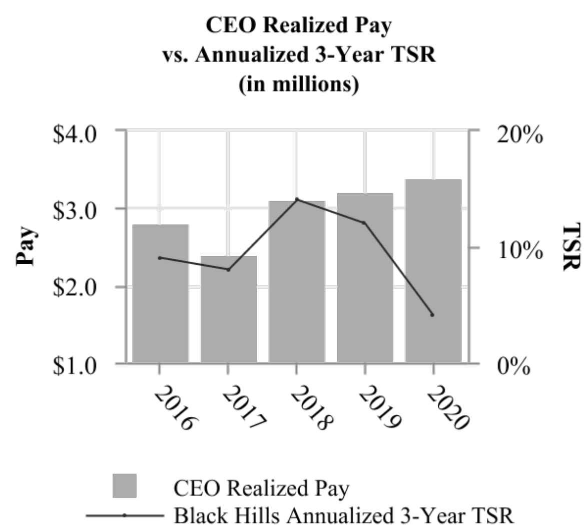
Pay Element	Performance Measure	2020 Results
Short-term Incentive: Payout of 119.57% of Target		
70 Percent	EPS from ongoing operations, as adjusted, target set at $3.62; threshold set at $3.26	$3.73 per share for incentive plan purposes
10 Percent	Total Case Incident Rate (TCIR), target set at 1.19; threshold set at 1.43	TCIR 1.00
10 Percent	Preventable Motor Vehicle Incident (PMVI), target set at 2.36; threshold set at 2.83	PMVI: 2.87
10 Percent	Employee Safety & Wellness Engagement, target set at 12,000 points; threshold set at 8,000 points	Points: 12,155
Long-term Incentive: Payout of 112.35% of Target		
Performance Share Award	Total Shareholder Return (TSR) relative to our Performance Peer Group measured over a three-year period	TSR 11.68% 55th Percentile Ranking in Performance Peer Group

PAY FOR PERFORMANCE

A key component of our executive compensation program is to link pay to performance.

The charts below illustrate the directional relationship between the compensation of our CEO (David R. Emery for 2016 through 2018, and Mr. Evans for 2019 and 2020), as reported in the Summary Compensation Table (excluding the change in pension value) and the growth in our Company for the last five years.

Since a large percentage of the CEO's pay as reported in the Summary Compensation Table represents potential pay, we believe it is also important to look at pay actually realized each year. In addition, since over 50 percent of our CEO pay is tied to Company performance, it is important to look at his realized pay as it is impacted by Company performance. The following graphics show reported pay and realized pay over the last five years and realized pay as it correlates to the Company's annualized 3-year total shareholder return, its long-term performance metric.



Reported pay includes base salary, actual annual incentive earned, the grant date fair value of long-term equity compensation and all other compensation, excluding the change in pension value, each as reported in the Summary Compensation Table.

Realized pay includes base salary, actual annual incentive earned and all other compensation, each as reported in the Summary Compensation Table, and the value of long-term performance compensation paid and stock awards vested in the applicable year.

KEY EXECUTIVE COMPENSATION OBJECTIVES

Overall, our goal is to target total direct compensation (the sum of base salary, short-term incentive at target and long-term incentive at target) around the median of the appropriate market. Our executive compensation is designed to maintain an appropriate and competitive balance between fixed and variable compensation components, short-and long-term compensation, and cash and stock-based compensation. We believe that the performance basis for determining compensation should differ by each reward component – base salary, short-term incentive and long-term incentive. Incentive measures (short-term and long-term) should emphasize objective, quantitative operating measures. The performance measures for our incentive compensation plans are discussed below.

SETTING EXECUTIVE COMPENSATION

Based upon our compensation philosophy, the Committee structures our executive compensation to motivate our officers to achieve specified business goals and to reward them for achieving such goals. The key steps the Committee follows in setting executive compensation are to:

- Analyze executive compensation market data to ensure market competitiveness
- Review the components of executive compensation, including base salary, short-term incentive, long-term incentive, retirement, and other benefits
- Review total compensation and structure
- Review executive officer performance, responsibilities, experience, and other factors cited above to determine individual compensation levels

Market Compensation Analysis

The market for our senior executive talent is national in scope and is not focused on any one geographic location, area or region of the country. As such, our executive compensation should be competitive with the national market for senior executives. It should also reflect the executive's responsibilities and duties and align with the compensation of executives at companies or business units of comparable size and complexity. The Committee gathers market information for our corporate executives from the electric and gas utility industry and also reviews general industry data as an additional reference.

The Committee selects and retains the services of an independent consulting firm to periodically:

- Provide information regarding practices and trends in compensation programs
- Review and evaluate our compensation program as compared to compensation practices of other companies with similar characteristics, including size, complexity, and type of business
- Review and assist with the establishment of a peer group of companies
- Provide a compensation analysis of the executive positions

The Committee used the services of Willis Towers Watson to evaluate 2020 compensation. It gathered data from nationally recognized survey providers, as well as specific peer companies through public filings, which included:

i. Willis Towers Watson's 2019 Compensation Data Bank (energy services and general industry); and
ii. 20 peer companies representing the utility and energy industry.

The 20 peer companies ranged in annual revenue size from approximately $545 million to $6.9 billion, with the median at $2.0 billion. The Company's 2020 revenue was $1.7 billion. The survey data was adjusted for our relative revenue size using regression analysis. Our compensation peer companies included in the analysis for 2020 compensation decisions were:

ALLETE Inc.	IDACORP Inc.	ONE Gas, Inc.
Alliant Energy Corporation	MGE Energy Inc.	Pinnacle West Capital Corp.
Ameren Corporation	New Jersey Resources Corp.	PNM Resources, Inc.
Atmos Energy Corp.	NiSource, Inc.	Portland General Electric Co.
Avista Corp.	Northwest Natural Holding Co.	South Jersey Industries, Inc.
CMS Energy Corp.	NorthWestern Corp.	Spire, Inc.
Hawaiian Electric Ind., Inc.	OGE Energy Corp.	

The above peer companies were chosen by the Compensation Committee as the Compensation Peer Group after engaging Willis Towers Watson to do an extensive review. Approximately 70 percent of the above companies are a subset of the Edison Electric Institute (EEI) Index, our Performance Peer Group, and were chosen because they were within our revenue range of 0.3x - 4.0x our size and market capitalization range of 0.40x - 2.5x our size. The EEI Index is comprised of electric utilities and combination gas and electric utilities. In addition, approximately 30 percent of the peer companies above were added to provide a mix of gas utilities.

The salary surveys are one of several factors the Committee uses in setting appropriate compensation levels. Other factors include Company performance, individual performance and experience, the level and nature of the executive's responsibilities, internal equity considerations and discussions with the CEO related to the other senior executive officers.

Components of Executive Compensation

The components of our executive compensation program consist of a base salary, a short-term incentive plan, and long-term incentives. In addition, we provide retirement and other benefits.

The majority of the executives' total compensation is granted as incentive compensation. Incentive compensation is intended to motivate and encourage our executives to drive performance and achieve superior results for our shareholders and align realized pay with stock performance. The Committee periodically reviews information provided by its compensation consultant to inform its determination of the appropriate level and mix of total compensation. The Committee believes that a significant portion of total target compensation should be comprised of incentive compensation. In order to reward long-term growth while still encouraging focus on short-term results, the Committee establishes incentive targets that emphasize long-term compensation at a greater level than short-term compensation.

The Committee reviews all components of each senior executive officer's compensation, including salary, short-term incentive, equity and other long-term incentive compensation values granted, and the current and potential value of the executive officer's total Black Hills Corporation equity holdings.

Base Salary. Base salaries for all officers are reviewed annually. We also adjust the base salary of our executives at the time of a promotion or material change in job responsibility, as appropriate. Evaluation of 2020 base salary adjustments occurred in January 2020. The base salary component of each position was compared to the median of the market data provided by the compensation consultant. The market data indicated that the salaries generally aligned with the utility industry median and are below comparable general industry levels. The actual base salary of each officer was determined by the executive's performance, the experience level of the officer, the executive's current position in a market-based salary range, and internal pay relationships.

	2019 Base Salary	2020 Base Salary
Evans, CEO	$750,000	$790,000
Kinzley, CFO	$420,000	$454,000
Iverson, GC	$375,000	$386,000
Wevik, UOO	$356,606	$407,000
Buchholz, SIO	$340,000	$340,000

Short-Term Incentive. Our Short-Term Incentive Plan is designed to recognize and reward the contributions of individual executives as well as the contributions that group performance makes to overall corporate success. In

2020, the Committee recommended and the Board approved including a health and wellness engagement metric, based upon average employee participation points in a health and wellness application, as a component of the short-term incentive goals. The 2020 short-term incentive was based seventy percent on earnings per share targets, twenty percent on safety performance targets, and ten percent on health and wellness targets. The Committee believes that these performance measures closely align interests with shareholders and foster teamwork and cooperation within the officer team. The short-term incentive, after applicable tax withholding, is distributed to the officer in the form of cash. Target award levels are established as a percentage of each participant's base salary. A target award is typically set around the benchmark market 50th percentile short-term incentive target award for comparable positions. The actual payout, if any, will vary, based on attainment of pre-established performance goals, between 50 and 200 percent of the individual executive's short-term incentive target award level.

The Committee approves the target level for each officer in January, which applies to performance in the upcoming plan year. Target levels are derived in part from competitive data provided by the compensation consultant and in part by the Committee's judgment regarding internal equity, retention and an individual executive's expected contribution to the achievement of our strategic objectives. The target levels for our Named Executive Officers are shown below:

Short-Term Incentive Target				
	2019		2020	
	% Amount	$ Amount	% Amount	$ Amount
Evans, CEO	100%	$750,000	100%	$790,000
Kinzley, CFO	65%	$273,000	65%	$295,100
Iverson, GC	60%	$225,000	60%	$231,600
Wevik, UOO	50%	$178,303	70%	$284,900
Buchholz, SIO	50%	$170,000	55%	$187,000

The threshold, target and maximum payout levels for our Named Executive Officers under the 2020 Short-Term Incentive Plan are shown in the Grants of Plan Based Awards in 2020 table on page 41, under the heading "Estimated Future Payouts Under Non-Equity Incentive Plan Awards."

Early in the first quarter, the Committee evaluates actual performance in relation to the prior year's targets and approves the actual payment of awards related to the prior plan year. The Committee reserves the discretion to adjust any award, and will review and take into account individual performance, level of contribution, and the accomplishment of specific project goals that were initiated throughout the plan year. The Committee also reserves discretion with respect to any payout related to safety goals if we experience an employee or contractor fatality during the plan period.

The Committee selected an earnings per share goal based on ongoing operations, as adjusted, for 2020, two safety performance goals, and one employee health and wellness goal. These goals meet the objectives of the plan, including:

- Align the interests of the plan participants and the shareholders
- Motivate employees to strive to achieve superior operating results
- Provide an incentive reflective of core operating performance
- Ensure "buy-in" from participants with easily understood metrics
- Meet the performance objectives of the plan to achieve over time an average payout equal to market competitive levels

The Committee has defined earnings per share from ongoing operations, as adjusted, to be GAAP earnings per share adjusted for unique one-time non-budgeted events (similar to those items adjusted for when reporting non-GAAP earnings for external purposes), including external acquisition costs, impairments, transaction financing costs, unique tax transactions, and other items the Committee deems not reflective of ongoing operations and the value created for shareholders.

The Committee approved the goals for 2020 for the senior officers as follows:

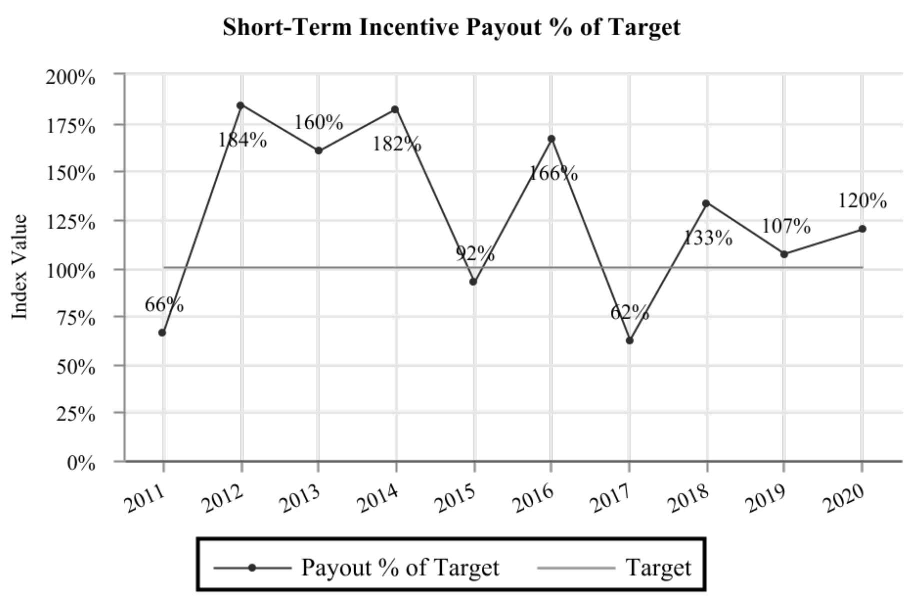
2020 Short-Term Incentive Metrics				
		Performance Goals		
Incentive	Value	Threshold	Target	Maximum
EPS from ongoing operations, as adjusted	70%	$3.26	$3.62	$3.98
Total Case Incident Rate (TCIR)	10%	1.43	1.19	0.95
Preventable Motor Vehicle Incidents (PMVI)	10%	2.83	2.36	1.89
Employee Safety & Wellness Engagement	10%	8,000 points	12,000 points	16,000 points
Payout percentage of target for each metric		50%	100%	200%

On January 26, 2021, the Committee approved a payout of 119.57 percent of target under the 2020 Short-Term Incentive Plan. The payout was based for incentive plan purposes on the attainment of the following:

- Our 2020 earnings per share were $3.73 per share, which was above our target earnings per share goal, resulting in a payout of 130.39 percent for 70 percent of the target incentive.
- Our 2020 TCIR was 1.0, which was better than our target resulting in a payout of 179.2 percent for 10 percent of the target incentive.
- Our 2020 PMVI was 2.87, which was below our threshold and resulted in no payout of the target incentive.
- Our 2020 average employee safety & wellness engagement points for all employees was 12,155 points which was above our target resulting in a payout of 103.9 percent for 10 percent of the target incentive.

Earnings per share from ongoing operations, as adjusted, for incentive plan purposes were the same as earnings per share from continuing operations, as adjusted, reported externally to our investors (and reconciled to GAAP earnings per share in Appendix A). For 2020, actual adjustments included impairment of an oil and gas investment, which is not indicative of ongoing performance and accordingly was reflected as an as-adjusted basis.

Payouts under the Short-Term Incentive Plan have varied over the last 10 years as shown in the graph below.



Actual awards made to each of our Named Executive Officers under the Short-Term Incentive Plan for 2020 are included in the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table on page 39.

Long-Term Incentive. Long-term incentive compensation is comprised of grants made by the Committee under our 2015 Omnibus Incentive Plan. Long-term incentive compensation is intended to:

- Promote achievement of corporate goals by linking the interests of participants to those of our shareholders
- Provide participants with an incentive for excellence in individual performance
- Promote teamwork among participants
- Motivate, retain, and attract the services of participants who make significant contributions to our success by allowing participants to share in such success
- Meet the performance objectives of the plan to achieve over-time, an average payout equal to market competitive levels

The Committee oversees the administration of the 2015 Omnibus Incentive Plan with full power and authority to determine when and to whom awards will be granted, along with the type, amount and other terms and conditions of each award. The long-term incentive compensation component is composed of performance shares and restricted stock. The Committee chose these components because linking executive compensation to stock price appreciation and total shareholder return is an effective way to align the interests of management with those of our shareholders. The Committee selected total shareholder return as the goal for the performance shares because it believes executive pay under a long-term, capital accumulation program should mirror our performance in shareholder return as compared to our Performance Peer Group of companies.

The value of long-term incentives awarded is based primarily on competitive market-based data presented by the compensation consultant to the Committee, the impact each position has on our shareholder return and internal pay relationships. The actual amount realized will vary from the target award amounts. The Committee approved the target long-term incentive compensation level for each officer in January 2020. The 2020 long-term incentive was adjusted for the majority of the Named Executive Officers to increase competitiveness within the market median compensation levels.

NEO Long-Term Incentive Target Compensation

	2019	2020
Evans, CEO	$1,500,000	$1,775,000
Kinzley, CFO	$510,000	$525,000
Iverson, GC	$390,000	$415,000
Wevik, UOO	$250,000	$400,000
Buchholz, SIO	$240,000	$240,000

2020 NEO Long-Term Incentive Compensation as a Percentage of Base Salary

	Evans, CEO	**Kinzley, CFO**	**Iverson, GC**	**Wevik, UOO**	**Buchholz, SIO**
% of Base Salary	225%	116%	108%	98%	71%

The variance in percentage of base salary for the long-term incentive value of our Named Executive Officers reflects our philosophy that certain officers should have more of their total compensation at risk because they hold positions that have a greater impact on our long-term results and this is also consistent with market practice.

Performance shares are used to deliver 50 percent of the long-term incentive award opportunity, with the remaining 50 percent delivered in the form of restricted stock that vests ratably over three years. The number of shares of performance shares and restricted stock granted in 2020 are reflected in the tables in the *Performance Shares* and *Restricted Stock* sections that follow.

Performance Shares. Participants are awarded a target number of performance shares based upon the value of the individual performance share component approved by the Committee, divided by the Beginning Stock Price. The Beginning Stock Price is the average of the closing price of our common stock for the 20 trading days immediately preceding the beginning of the performance period. Vesting of performance shares is based on our total shareholder return over designated performance periods, as measured against our Performance Peer Group. The final value of the performance shares is based upon the number of shares of common stock that are ultimately earned, based upon our performance in relation to the performance criteria.

The Committee, with the guidance of its independent compensation consultant, periodically conducts a review of the market competitiveness of our performance share plans. A summary of the performance criteria for each three-year plan period is summarized in the table below.

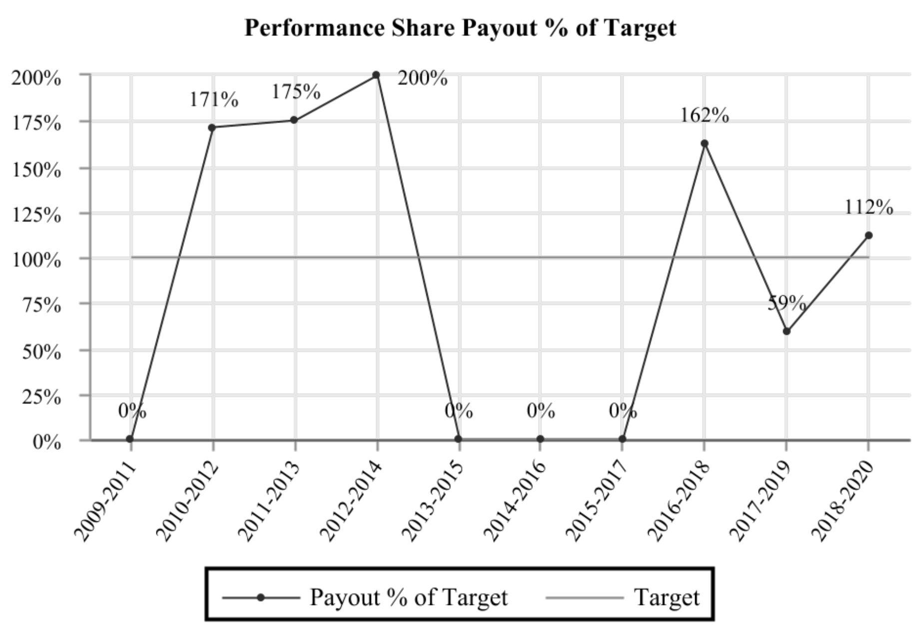
Performance Share Plans			
Percentile Ranking for Threshold Payout of 25% of Target Shares	Percentile Ranking for Target Payout of 100% of Target Shares	Percentile Ranking for Maximum Payout Level	Possible Payout Range of Target
25th percentile	50th percentile	90th percentile	0-200%

In addition, beginning with the 2017-2019 performance plan, our plans provide: (i) a threshold payout if relative TSR performance is below threshold but our TSR is at least 35 percent for the performance period; and (ii) the performance share plan payout is capped at 100 percent of target if TSR is negative. The additional provisions are intended to reduce the impact of one peer company's performance on the relative TSR plan, and also increase accountability and expectations related to the Company's performance.

The performance awards and dividend equivalents, if earned, are paid 50 percent in cash and 50 percent in common stock. All payroll deductions and applicable tax withholding related to the award are withheld from the cash portion.

The Committee, with the guidance of its independent compensation consultant, periodically conducts a review of our Performance Peer Group to which our performance should be compared. Due to the extensive merger and acquisition activity in the industry and its contribution to relative performance volatility, the Committee chose to use the companies in the EEI Index as the Performance Peer Group for financial performance tracking beginning with the 2017-2019 performance period.

Payouts under the Performance Share Plan have varied significantly over the last 10 years, as shown in the graph below.



Each performance share period extends for three years. For the recently completed performance period, January 1, 2018 to December 31, 2020, our total shareholder return was 12 percent, which ranked at the 55th percentile of our Performance Peer Group, resulting in a payout at 112 percent of target.

Target shares for each of our Named Executive Officers for the outstanding performance periods are as follows:

	January 1, 2019 to December 31, 2021 Performance Period	January 1, 2020 to December 31, 2022 Performance Period
Evans, CEO	11,524	11,460
Kinzley, CFO	3,918	3,390
Iverson, GC	2,996	2,679
Wevik, UOO	1,921	2,583
Buchholz, SIO	1,844	1,550

Actual payouts, if any, will be determined based upon our total shareholder return for the plan period in comparison to our Performance Peer Group.

Restricted Stock. Restricted stock awarded as long-term incentives vest one-third each year over a three-year period, and automatically vests in its entirety upon death, disability or a change in control. Dividends are paid on the restricted stock. Unvested restricted stock is forfeited if an officer's employment is terminated for any reason other than death, disability or in the event of a change in control.

The number of shares of restricted stock awarded in 2020 for each of our Named Executive Officers is shown below and is included in the Grants of Plan Based Awards in 2020 table under the heading "All Other Stock Awards: Number of Shares of Stock or Units" and "Grant Date Fair Value of Stock Awards" on page 41.

	Restricted Stock Shares
Evans, CEO	10,507
Kinzley, CFO	3,108
Iverson, GC	2,456
Wevik, UOO	2,368
Buchholz, SIO	1,421

<u>Performance Evaluation</u>

Role of Executive Officers in Compensation Decisions. The CEO annually reviews the performance of each of our senior executive officers. Based upon these performance reviews, market analysis conducted by compensation consultants and discussions with our Senior Vice President - Chief Human Resources Officer, the CEO recommends the compensation for this group of officers to the Committee.

Role of the Committee and Board in Setting Executive Compensation. The Committee reviews and establishes the Company's financial targets and the CEO's goals and objectives for the year. After the end of each year, the Committee evaluates the CEO's performance in light of established goals and objectives, with input from the other independent directors. Based upon the Committee's evaluation and recommendation, the independent directors of the Board set the CEO's annual compensation, including salary, short-term incentive, long-term incentive and equity compensation.

The Committee reviews the CEO's recommended compensation levels for our senior executive officers. The Committee may approve the CEO's compensation recommendations for this group of officers or exercise its discretion in modifying any of the recommended compensation and award levels in its review and approval process. The Committee is required to approve all decisions regarding equity awards to our officers.

Summary

In total, the Committee believes that the 2020 compensation actions, decisions and outcomes strongly reflect and reinforce our compensation philosophy and, in particular, emphasize the alignment between compensation and both performance and shareholder interests. At our 2020 annual meeting, shareholders owning 97 percent of the shares that were voted on this matter approved our executive compensation for 2019, which we consider highly supportive of our current compensation philosophy. In connection with establishing the 2020 executive compensation program, the Board reviewed the results of the say on pay vote, as well as market data and performance indicators.

Governance Best Practices

We have several governance programs in place to align our executive compensation with shareholder interests and to mitigate risks in our plans. These programs include stock ownership guidelines, clawback provisions in our short-term and long-term incentive award agreements, and the prohibition of hedging or pledging of Company stock.

STOCK OWNERSHIP GUIDELINES

The Committee has implemented stock ownership guidelines that apply to all officers based upon their level of responsibility. We believe it is important for our officers to hold a significant amount of our common stock to further align their interests with the interest of our shareholders. A “retention ratio” approach to stock ownership is incorporated into the guidelines. Officers are required to retain 100 percent of all shares owned, including shares awarded through our incentive plans (net of share withholding for taxes and, in the case of cashless stock option exercises, net of the exercise price and withholding for taxes) until specific ownership goals are achieved.

The guidelines are shown below.

Position	Stock Ownership Value as Multiple of Base Salary
CEO	6X
CFO	4X
Other Senior Officers	3X

At least annually, the Compensation Committee reviews common stock ownership to confirm the officers have met or are progressing toward their stock ownership guidelines. Generally, an officer may not sell common stock unless he or she owns common stock in excess of 110 percent of the applicable stock ownership guideline. All of our Named Executive Officers have exceeded their stock ownership guidelines.

2020 BENEFITS

Retirement Benefits. We maintain a variety of employee benefit plans and programs in which our executive officers may participate. We believe it is important to provide post-employment benefits to our executive officers and the benefits we provide approximate retirement benefits paid by other employers to executives in similar positions. The Committee periodically reviews the benefits provided, with assistance from its compensation consultant, to maintain a market-based benefits package. None of our Named Executive Officers received any pension benefit payments in 2020.

Several years ago, we adopted a defined contribution plan design as our primary retirement plan and amended our Defined Benefit Pension Plan (“Pension Plan”) for all eligible employees to incorporate a partial freeze in which the accrual of benefits ceased for certain participants while other participants were allowed an election to continue to accrue benefits. Messrs. Buchholz and Wevik are our only Named Executive Officers who met the age and service requirements allowing them to continue to accrue benefits under the Pension Plan. Employees who no longer accrue benefits under the Pension Plan now receive Company Retirement Contributions (“Retirement Contributions”) in the Retirement Savings Plan. The Retirement Contributions are an age and service points-based calculation.

The 401(k) Retirement Savings Plan is offered to all our eligible employees and we provide matching contributions for certain eligible participants. All of our Named Executive Officers are participants in the 401(k) Retirement

Savings Plan and received matching contributions in 2020. The matching contributions and the Retirement Contributions are included as “All Other Compensation” in the Summary Compensation Table on page 39.

We also provide nonqualified plans to certain officers because of Internal Revenue Code limitations imposed on the qualified plans. The level of retirement benefits provided by the Pension Plan and Nonqualified Plans for each of our Named Executive Officers is reflected in the Pension Benefits for 2020 table on page 44. Our contributions to the Nonqualified Deferred Compensation Plan are included in the All Other Compensation column of the Summary Compensation Table on page 39 and the aggregate Nonqualified Deferred Compensation balance at December 31, 2020 is reported in the Nonqualified Deferred Compensation for 2020 table on page 46. These retirement benefits are explained in more detail in the accompanying narrative to the tables.

Other Personal Benefits. We provide the personal use of a Company vehicle, executive health services, and limited reimbursement of financial planning services as benefits to our executive officers. The specific amount attributable to these benefits in 2020 is disclosed in the Summary Compensation Table on page 39. The Committee periodically reviews the other personal benefits provided to our executive officers and believes the current benefits are reasonable and consistent with our overall compensation program.

CHANGE IN CONTROL PAYMENTS

Our Named Executive Officers may also receive severance benefits in the event of a change in control. We have no employment agreements with our Named Executive Officers. However, change in control agreements are common among our Compensation Peer Group and the Committee and our Board of Directors believe providing these agreements to our corporate officers protects our shareholder interests in the event of a change in control by helping assure management focus and continuity. Our change in control agreements have expiration dates and our Board of Directors conducts a thorough review of the change in control agreements at each renewal period. Our current change in control agreements expire November 15, 2022. In general, our change in control agreements provide a severance payment of up to 2.99 times average compensation for Mr. Evans, and up to two times average compensation for the other Named Executive Officers. The change in control agreements do not provide for excise tax gross-ups and contain a “double trigger,” providing benefits in association with:

(1) a change in control, and
(2) (i) a termination of employment other than by death, disability or by us for cause, or
    (ii) a termination by the employee for good reason.

See the Potential Payments upon Termination or Change in Control table on page 48 and the accompanying narrative for more information regarding our change in control agreements and estimated payments associated with a change in control.

TAX AND ACCOUNTING IMPLICATIONS

Section 162(m) of the U.S. Internal Revenue Code of 1986, as amended, limits the tax deductibility by a corporation of compensation in excess of $1 million paid to certain of its officers. Section 162(m) as in effect prior to the enactment of tax reform legislation in December 2017 generally disallowed a tax deduction to public companies for compensation of more than $1 million paid in any taxable year to each “covered employee,” consisting of the CEO and the three other highest paid executive officers employed at the end of the year (other than the CFO). Performance-based compensation was exempt from this deduction limitation if the Company met specified requirements set forth in the Code and applicable Treasury Regulations.

For years beginning January 1, 2018, there is no exception from the deduction limit under Section 162(m) for performance based compensation unless it qualifies for transitional relief applicable to certain binding, written performance-based compensation arrangements that were in place as of November 2, 2017, and were not materially modified after that date. In addition, “covered employees” also include any person who served as CEO or CFO at any time during a taxable year, as well as any person who was ever identified as a covered employee in 2017 or any subsequent year. The Committee continues to believe that shareholder interests are best served if its discretion and flexibility in structuring and awarding compensation is not restricted, even though some past and/or future compensation awards result in non-deductible compensation expenses to the Company. The Committee’s ability to continue to provide a competitive compensation package to attract, motivate and retain the Company’s most senior executives is considered critical to the Company's success and to advancing the interests of its shareholders.

CLAWBACK POLICY

We have a policy that if an accounting restatement occurs after incentive payments have been made, due to the results of misconduct associated with financial reporting, the Committee will seek repayment of the incentive compensation from our CEO and CFO, and the Committee has the discretion to request repayment of incentive compensation from our other officers, taking into consideration the individual roles and responsibilities prompting the restatement.

In addition, our award agreements for restricted stock and performance shares include clawback provisions whereby the participant may be required to repay all income or gains previously realized in respect of such awards if his or her: (1) employment is terminated for cause; (2) if within one year following termination of employment, the Board determines that the participant engaged in conduct prior to his or her termination that would have constituted the basis for a termination of employment for cause; (3) if the participant makes a public statement that is materially detrimental to the interests or reputation of the Company; (4) if the employee violates in any material respect any policy or any code of ethics; or (5) if the participant engages in any fraudulent, illegal or other misconduct.

HEDGING POLICY

Our directors, executive officers, and employees are prohibited from engaging in hedging transactions involving, and from pledging, Company stock, including holding our stock in a margin account. This prohibition extends to all hedging transactions, including zero cost collars and forward sale contracts.

REPORT OF THE COMPENSATION COMMITTEE

The Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management and, based on such review and discussions, the Compensation Committee recommended to our Board of Directors that the Compensation Discussion and Analysis be included in this proxy statement.

THE COMPENSATION COMMITTEE

Teresa A. Taylor, Chair
Tony A. Jensen
Michael H. Madison
Rebecca B. Roberts

SUMMARY COMPENSATION TABLE

The following table sets forth the total compensation paid or earned by each of our Named Executive Officers for the years ended December 31, 2020, 2019 and 2018. We have no employment agreements with our Named Executive Officers.

Name and Principal Position	Year	Salary	Stock Awards(1)	Non-Equity Incentive Plan Compensation(2)	Changes in Pension Value and Nonqualified Deferred Compensation Earnings (3)	All Other Compensation(4)	Total
Linden R. Evans	2020	$783,333	$1,820,599	$936,632	$79,100	$601,450	$4,221,114
President and Chief Executive Officer	2019	$713,333	$1,541,811	$800,400	$110,158	$473,600	$3,639,302
	2018	$530,000	$859,369	$492,132	$—	$306,330	$2,187,831
Richard W. Kinzley	2020	$448,333	$538,547	$348,447	$51,945	$263,528	$1,650,800
Sr. Vice President and Chief Financial Officer	2019	$413,500	$524,220	$291,346	$68,631	$254,366	$1,552,063
	2018	$381,000	$491,036	$303,238	$—	$195,249	$1,370,523
Brian G. Iverson	2020	$384,167	$425,583	$275,609	$23,339	$157,216	$1,265,913
Sr. Vice President, General Counsel and Chief Compliance Officer	2019	$370,833	$400,825	$240,120	$31,927	$156,990	$1,200,695
	2018	$350,000	$383,678	$255,351	$—	$123,852	$1,112,881
Stuart A. Wevik	2020	$398,601	$410,333	$333,625	$371,933	$121,870	$1,636,362
Sr. Vice President - Utility Operations							
Scott A. Buchholz	2020	$340,000	$246,233	$223,596	$769,491	$129,896	$1,709,216
Sr. Vice President - Strategic Initiatives	2019	$336,667	$246,720	$181,424	$756,325	$134,089	$1,655,225
	2018	$320,000	$245,514	$212,240	$38,765	$111,285	$927,804

(1) Stock Awards represent the grant date fair value related to restricted stock and performance shares that have been granted as a component of long-term incentive compensation. The grant date fair value is computed in accordance with the provisions of accounting standards for stock compensation. Assumptions used in the calculation of these amounts are included in Note 12 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2020. The amounts shown for the performance shares represent the values that are based on the achievement of 100% of the target performance. Assuming achievement of the maximum 200% of target performance, the value of the performance shares would be: $1,866,146 for Mr. Evans, $552,028 for Mr. Kinzley, $436,248 for Mr. Iverson, $420,616 for Mr. Wevik, and $252,402 for Mr. Buchholz.

(2) Non-Equity Incentive Plan Compensation represents amounts earned under the Short-Term Incentive Plan. The Compensation Committee approved the payout of the 2020 awards on January 26, 2021 and the awards were paid on March 5, 2021.

(3) Change in Pension Value and Nonqualified Deferred Compensation Earnings represents the net positive increase in actuarial value of the Pension Plan and Pension Restoration Benefit ("PRB") for the respective years. These benefits have been valued using the assumptions disclosed in Note 15 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2020. Because these assumptions sometimes change between measurement dates, the change in value reflects not only the change in value due to additional benefits earned during the period and the passage of time but also reflects the change in value caused by changes in the underlying actuarial assumptions. This has created significant volatility in the last three years with large increases in 2020 and 2019 and a large decrease in 2018, primarily related to the change in discount rates used to calculate the present value of these benefits. A value of zero is shown in the Summary Compensation Table for certain officers in 2018 because the SEC does not allow a negative number to be disclosed in the table.

The Pension Plan and PRB were frozen effective January 1, 2010 for participants who did not satisfy the age 45 and 10 years of service eligibility. Messrs. Evans, Kinzley and Iverson did not meet the eligibility choice criteria and their Defined Pension and PRB benefits were frozen.

Our Named Executive Officers receive employer contributions into a Nonqualified Deferred Compensation Plan ("NQDC"). The NQDC employer contributions are reported in the All Other Compensation column. No Named Executive Officer received preferential or above-market earnings on nonqualified deferred compensation. The change in value attributed to each Named Executive Officer from each plan is shown in the table below.

	Year	Defined Benefit Plan	PRB	PEP	Total Change in Pension Value
Linden R. Evans	2020	$43,576	$35,524	$—	$79,100
	2019	$59,664	$50,494	$—	$110,158
	2018	($19,607)	($15,074)	$—	($34,681)
Richard W. Kinzley	2020	$48,872	$3,073	$—	$51,945
	2019	$64,428	$4,203	$—	$68,631
	2018	($23,542)	($1,394)	$—	($24,936)
Brian G. Iverson	2020	$23,339	$—	$—	$23,339
	2019	$31,927	$—	$—	$31,927
	2018	($10,523)	$—	$—	($10,523)
Stuart A. Wevik	2020	$371,933	$—	$—	$371,933
	2019	$—	$—	$—	$—
	2018	$—	$—	$—	$—
Scott A. Buchholz	2020	$338,532	$430,959	$—	$769,491
	2019	$396,434	$359,891	$—	$756,325
	2018	($42,215)	$80,980	$—	$38,765

(4) All Other Compensation includes amounts allocated under the 401(k) match, defined contributions, Company contributions to defined benefit and deferred compensation plans, dividends received on restricted stock and unvested restricted stock units and other personal benefits. The Other Personal Benefits column reflects the personal use of a Company vehicle, executive health, and financial planning services for each NEO.

	Year	401(k) Match	Defined Contributions	NQDC Contributions	Dividends on Restricted Stock	Other Personal Benefits	Total Other Compensation
Linden R. Evans	2020	$14,700	$22,780	$498,195	$44,031	$21,723	$601,450
Richard W. Kinzley	2020	$17,100	$20,400	$192,816	$15,305	$17,908	$263,528
Brian G. Iverson	2020	$17,100	$20,400	$97,376	$11,931	$10,409	$157,216
Stuart A. Wevik	2020	$17,100	$—	$69,886	$11,440	$23,443	$121,870
Scott A. Buchholz	2020	$17,100	$—	$87,181	$7,211	$18,404	$129,896

GRANTS OF PLAN BASED AWARDS IN 2020[1]

Name	Grant Date	Date of Compensation Committee Action	Estimated Future Payouts Under Non-Equity Incentive Plan Awards[2] Threshold ($)	Target ($)	Maximum ($)	Estimated Future Payouts Under Equity Incentive Plan Awards[3] Threshold (#)	Target (#)	Maximum (#)	All Other Stock Awards: Number of Shares of Stock or Units[4] (#)	Grant Date Fair Value of Stock Awards[5] ($)
Linden R. Evans			395,000	790,000	1,580,000					
	1/28/20	1/28/20				2,865	11,460	22,920		933,073
	2/10/20	1/28/20							10,507	887,526
Richard W. Kinzley			147,550	295,100	590,200					
	1/28/20	1/28/20				848	3,390	6,780		276,014
	2/10/20	1/28/20							3,108	262,533
Brian G. Iverson			115,800	231,600	463,200					
	1/28/20	1/28/20				670	2,679	5,358		218,124
	2/10/20	1/28/20							2,456	207,458
Stuart A. Wevik			142,450	284,900	569,800					
	1/28/20	1/28/20				646	2,583	5,166		210,308
	2/10/20	1/28/20							2,368	200,025
Scott A. Buchholz			93,500	187,000	374,000					
	1/28/20	1/28/20				388	1,550	3,100		126,201
	2/10/20	1/28/20							1,421	120,032

(1) No stock options were granted to our Named Executive Officers in 2020.

(2) The columns under “Estimated Future Payouts Under Non-Equity Incentive Plan Awards” show the range of payouts for 2020 performance under our Short-Term Incentive Plan as described in the Compensation Discussion and Analysis under the section titled “Short-Term Incentive” on page 30. If the performance criteria are met, payouts can range from 50 percent of target at the threshold level to 200 percent of target at the maximum level. The 2021 bonus payment for 2020 performance has been made based on achieving the criteria described in the Compensation Discussion and Analysis, at 120 percent of target, and is shown in the Summary Compensation Table on page 39 in the column titled “Non-Equity Incentive Plan Compensation.”

(3) The columns under “Estimated Future Payouts Under Equity Incentive Plan Awards” show the range of payouts (in shares of stock) for the January 1, 2020 to December 31, 2022 performance period as described in the Compensation Discussion and Analysis under the section titled “Long-Term Incentive” on page 33. If the performance criteria are met, payouts can range from 25 percent of target to 200 percent of target. If a participant retires, suffers a disability or dies during the performance period, the participant or the participant’s estate is entitled to that portion of the number of performance shares as such participant would have been entitled to had he or she remained employed, prorated for the number of months served. Performance shares are forfeited if employment is terminated for any other reason. During the performance period, dividends and other distributions paid with respect to the shares of common stock accrue for the benefit of the participant and are paid out at the end of the performance period.

(4) The column “All Other Stock Awards” reflects the number of shares of restricted stock granted on February 11, 2020 under our 2015 Omnibus Incentive Plan. The restricted stock vests one-third each year over a three-year period, and automatically vests upon death, disability or a change in control. Unvested restricted stock is forfeited if employment is terminated for any other reason. Dividends are paid on the restricted stock and the dividends that were paid in 2020 are included in the column titled “All Other Compensation” in the Summary Compensation Table on page 39.

(5) The column “Grant Date Fair Value of Stock Awards” reflects the grant date fair value of each equity award computed in accordance with the provisions of accounting standards for stock compensation. The grant date fair value for the performance shares was $81.42 per share and was calculated using a Monte Carlo simulation model. Assumptions used in the calculation are included in Note 12 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2020. The grant date fair value for the restricted stock was $84.47 per share for the February 11, 2020 grant, which was the market value of our common stock on the date of grant as reported on the NYSE.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END 2020[(1)]

	Stock Awards			
Name	Number of Shares or Units of Stock That Have Not Vested[(2)] (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested[(2)] (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)
Linden R. Evans	20,291	1,246,882	23,194	1,411,275
Richard W. Kinzley	7,053	433,407	9,797	594,013
Brian G. Iverson	5,498	337,852	7,597	460,577
Stuart A. Wevik	5,162	317,205	4,926	298,767
Scott A. Buchholz	3,323	204,198	4,747	287,675

(1) There were no stock options outstanding at December 31, 2020 for our Named Executive Officers.

(2) Vesting dates for restricted stock and performance shares are shown in the table below. The performance shares shown with a vesting date of December 31, 2020, are the actual equivalent shares, including dividend equivalents, earned for the performance period ended December 31, 2020. On January 26, 2021, the Compensation Committee confirmed that the performance criteria were met and there would be a payout of 112 percent of target. The performance shares with a vesting date of December 31, 2021 and a vesting date of December 31, 2022 are shown at the threshold and maximum payout levels, respectively, based upon performance as of December 31, 2020.

Name	Unvested Restricted Stock		Unvested and Unearned Performance Shares	
	# of Shares	Vesting Date	# of Shares	Vesting Date
Linden R. Evans	2,672	02/05/21	8,805	12/31/20
	3,502	02/10/21	11,524	12/31/21
	3,556	02/11/21	2,865	12/31/22
	3,502	02/10/22		
	3,556	02/11/22		
	3,503	02/10/23		
Richard W. Kinzley	1,527	02/05/21	5,031	12/31/20
	1,036	02/10/21	3,918	12/31/21
	1,209	02/11/21	848	12/31/22
	1,036	02/10/22		
	1,209	02/11/22		
	1,036	02/10/23		
Brian G. Iverson	1193	02/05/21	3,931	12/31/20
	818	02/10/21	2,996	12/31/21
	924	02/11/21	670	12/31/22
	819	02/10/22		
	925	02/11/22		
	819	02/10/23		
Stuart A. Wevik	716	02/05/21	2,359	12/31/20
	789	02/10/21	1,921	12/31/21
	593	02/11/21	646	12/31/22
	446	05/06/21		
	789	02/10/22		
	593	02/11/22		
	446	05/06/22		
	790	02/10/23		
Scott A. Buchholz	764	02/05/21	2,515	12/31/20
	473	02/10/21	1,844	12/31/21
	569	02/11/21	388	12/31/22
	474	02/10/22		
	569	02/11/22		
	474	02/10/23		

OPTION EXERCISES AND STOCK VESTED DURING 2020[1]

Name	Stock Awards[2]	
	Number of Shares Acquired on Vesting (#)	Value Realized on Vesting ($)
Linden R. Evans	12,555	$1,028,497
Richard W. Kinzley	6,335	$516,806
Brian G. Iverson	4,886	$398,660
Stuart A. Wevik	3,337	$262,109
Scott A. Buchholz	3,152	$256,990

(1) There were no stock options exercised during 2020.

(2) Reflects restricted stock that vested in 2020 and performance shares earned for the 2017-2019 performance period. The performance share payout was approved by the Compensation Committee on January 28, 2020 and paid out on February 4, 2020.

PENSION BENEFITS FOR 2020

Several years ago, we adopted a defined contribution plan design as our primary retirement plan and amended our Pension Plan and Nonqualified Pension Plans for all eligible employees to incorporate a partial freeze in which the accrual of benefits ceased for certain participants while other participants were allowed an election to continue to accrue benefits. Employees eligible to elect continued participation were those employees who were at least 45 years old and had at least 10 years of eligible service with us as of January 1, 2010. Messrs. Buchholz and Wevik are our only Named Executive Officers who met the age and service requirement and continue to accrue benefits under the Pension Plan. Mr. Buchholz is our only Named Executive Officer who met the requirements and continues to accrue benefits under the Pension Restoration Plan. Benefits under the Pension Plan and Pension Restoration Plan were frozen for Messrs. Evans, Kinzley and Iverson. None of our Named Executive Officers received any pension benefit payments during the fiscal year ended December 31, 2020.

The present value accumulated by each Named Executive Officer from each plan is shown in the table below:

Name	Plan Name	Number of Years of Credited Service[1] (#)	Present Value of Accumulated Benefit[2] ($)
Linden R. Evans	Pension Plan	8.58	359,200
	Pension Restoration Benefit	8.58	290,843
Richard W. Kinzley	Pension Plan	10.50	338,755
	Pension Restoration Benefit	10.50	21,136
Brian G. Iverson	Pension Plan	5.83	191,576
Stuart A. Wevik	Pension Plan	34.59	1,869,355
Scott A. Buchholz	Pension Plan	41.17	2,179,759
	Pension Restoration Plan	41.17	2,010,091

(1) The number of years of credited service represents the number of years used in determining the benefit for each plan.

(2) The present value of accumulated benefits was calculated assuming the participants will work until retirement, benefits commence at age 62 and using the discount rate, mortality rate and assumed payment form assumptions consistent with those disclosed in Note 15 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2020.

DEFINED BENEFIT PENSION PLAN

Our Pension Plan is a qualified pension plan in which all of our Named Executive Officers are included. As discussed above, several years ago we amended our Pension Plan to incorporate a partial freeze in which the accrual of benefits ceased for certain participants while other participants were allowed an election to continue to accrue benefits.

The Pension Plan provides benefits at retirement based on length of employment service and average compensation levels during the highest five consecutive years of the last ten years of service. For purposes of the benefit calculation, earnings include wages and other cash compensation received from us, including any bonus, commission, unused paid time off or incentive compensation. It also includes any elective before-tax contributions made by the employee to a Company-sponsored cafeteria plan or 401(k) plan. However, it does not include any expense reimbursements, taxable fringe benefits, moving expenses or moving/relocation allowances, nonqualified deferred compensation, non-cash incentives, stock options and any payments of long-term incentive compensation such as restricted stock or payments under performance share plans. The Internal Revenue Code places maximum limitations on the amount of compensation that may be recognized when determining benefits of qualified pension plans. In 2020, the maximum amount of compensation that could be recognized when determining compensation was $285,000 (called “covered compensation”). Our employees do not contribute to the plan. The amount of the annual contribution by us to the plan is based on an actuarial determination.

The benefit formula for the Named Executive Officers in the plan is the sum of (a) and (b) below.

(a) Credited Service after January 31, 2000

0.9% of average earnings (up to covered compensation), multiplied by credited service after January 31, 2000 minus the number of years of credited service before January 31, 2000	Plus	1.3% of average earnings in excess of covered compensation, multiplied by credited service after January 31, 2000 minus the number of years of credited service before January 31, 2000

Plus

(b) Credited Service before January 31, 2000

1.2% of average earnings (up to covered compensation), multiplied by credited service before January 31, 2000	Plus	1.6% of average earnings in excess of covered compensation, multiplied by credited service before January 31, 2000

Pension benefits are not reduced for social security benefits. The Internal Revenue Code places maximum limitations on annual benefit amounts that can be paid under qualified pension plans. In 2020, the maximum benefit payable under qualified pension plans was $230,000. Accrued benefits become 100 percent vested after an employee completes five years of service.

Normal retirement is defined as age 65 under the plan. However, a participant may retire and begin taking unreduced benefits at age 62 with five years of service. Participants who have completed at least five years of credited service can retire and receive defined benefit pension benefits as early as age 55. However, the retirement benefit will be reduced by five percent for each year of retirement before age 62. All our Named Executive Officers are currently age 55 or older and are entitled to early retirement benefits under this provision.

PENSION RESTORATION BENEFIT

We also have a Pension Restoration Benefit. This is a nonqualified supplemental plan, in which benefits are not tax deductible until paid. The plan is designed to provide the higher paid executive employee a retirement benefit which, when added to social security benefits and the pension to be received under the Pension Plan, will approximate retirement benefits being paid by other employers to their employees in similar executive positions. The employee’s pension from the qualified Pension Plan is limited by the Internal Revenue Code. The 2020 pension limit was set at $230,000 annually and the compensation taken into account in determining contributions and benefits could not exceed $285,000 and could not include nonqualified deferred compensation. The amount of deferred compensation paid under nonqualified plans is not subject to these limits.

As a result of the change in the Pension Plan discussed above, the benefits for certain officers (including Messrs. Evans, Kinzley and Iverson) under the Nonqualified Pension Plans were significantly reduced because the nonqualified benefit calculations were linked to the benefits earned in the Pension Plan. The Compensation Committee amended the Nonqualified Deferred Compensation Plan to provide non-elective nonqualified restoration benefits to those affected officers who were not eligible to continue accruing benefits under the Pension Plan and Nonqualified Pension Plans.

Pension Restoration Benefit. In the event that at the time of a participant's retirement, the participant's salary level exceeds the qualified Pension Plan annual compensation limitation ($285,000 in 2020) or includes nonqualified deferred compensation, then the participant will receive an additional benefit, called a "Pension Restoration Benefit," which is measured by the difference between (i) the monthly benefit that would have been provided to the participant under the Pension Plan as if there were no annual compensation limitation and no exclusion on nonqualified deferred compensation, and (ii) the monthly benefit to be provided to the participant under the Pension Plan. The Pension Restoration Benefit applies to all of the Named Executive Officers that have a pension benefit, with the exception of Messrs. Iverson and Wevik.

NONQUALIFIED DEFERRED COMPENSATION FOR 2020

We have a Nonqualified Deferred Compensation Plan for a select group of management or highly compensated employees. Eligibility to participate in the plan is determined by the Compensation Committee and primarily consists of corporate officers.

A summary of the activity in the plan and the aggregate balance as of December 31, 2020 for our Named Executive Officers is shown in the following table. Our Named Executive Officers received no withdrawals or distributions from the plan in 2020.

Name	Executive Contributions	Company Contributions in Last Fiscal Year(1)	Aggregate Earnings in Last Fiscal Year(2)	Aggregate Balance at Last Fiscal Year End(3)
Linden R. Evans	$—	$498,195	$491,589	$4,533,427
Richard W. Kinzley	$—	$192,816	$377,694	$2,119,769
Brian G. Iverson	$—	$97,376	$145,414	$866,811
Stuart A. Wevik	$—	$69,886	$59,623	$655,563
Scott A. Buchholz	$—	$87,181	$125,883	$1,193,584

(1) Our contributions represent non-elective Supplemental Matching and Retirement Contributions and Supplemental Target Contributions (defined in the paragraph below) and are included in the All Other Compensation column of the Summary Compensation Table. The value attributed from each contribution type to each Named Executive Officer in 2020 is shown in the table below:

Name	Supplemental Matching Contribution	Supplemental Retirement Contribution	Supplemental Target Contribution	Total Company Contributions
Linden R. Evans	$77,858	$103,811	$316,527	$498,195
Richard W. Kinzley	$27,227	$36,302	$129,286	$192,816
Brian G. Iverson	$20,339	$27,119	$49,919	$97,376
Stuart A. Wevik	$20,180	$—	$49,706	$69,886
Scott A. Buchholz	$14,185	$—	$72,997	$87,181

(2) Because amounts included in this column do not include above-market or preferential earnings, none of these amounts are included in the "Change in Pension Value and Nonqualified Deferred Compensation Earnings" column of the Summary Compensation Table.

(3) Messrs. Evans', Kinzley's, Iverson's, Wevik's and Buchholz's aggregate balances at December 31, 2020 include $1,098,201 $505,313, $255,817, $151,174 and $247,435, respectively, which are included in the Summary Compensation Table as 2020, 2019 and 2018 compensation.

Eligible employees may elect to defer up to 50 percent of their base salary, up to 100 percent of their Short-Term Incentive Plan award, and up to 100% of the cash portion of their Performance Share Plan award. In addition, the Nonqualified Deferred Compensation Plan was amended to provide certain officers whose Pension Plan benefit and Nonqualified Pension Plans' benefits were frozen with non-elective supplemental matching contributions equal to 6 percent of eligible compensation in excess of the Internal Revenue Code limit plus matching contributions, if any, lost under the 401(k) Retirement Savings Plan due to nondiscrimination test results and provides non-elective supplemental age and service points-based contributions that cannot be made to the 401(k) Retirement Savings Plan due to the Internal Revenue Code limit ("Supplemental Matching and Retirement Contributions"). It also provides supplemental target contributions equal to a percentage of compensation that may differ by executive, based on the executive's current age and length of service with us, as determined by the plans' actuary ("Supplemental Target Contributions"). Messrs. Evans, Kinzley, Iverson, Wevik and Buchholz received Supplemental Target Contributions of 20 percent, 17.5 percent, 8 percent, 8 percent and 14 percent, respectively.

The deferrals are deposited into hypothetical investment accounts where the participants may direct the investment of the deferrals as allowed by the plan. The investment options are the same as those offered to all employees in the 401(k) Retirement Savings Plan except for a fixed rate option, which was set at 3.91 percent in 2020. Investment earnings are credited to the participants' accounts. Upon retirement, we will distribute the account balance to the participant according to the distribution election filed with the Compensation Committee. The participants may elect either a lump sum payment to be paid within 30 days of retirement (requires a six-month deferral for benefits not vested as of December 31, 2004), or annual or monthly installments over a period of years designated by the participant, but not to exceed 10 years. As of January 1, 2021, Messrs. Evans, Kinzley, Iverson, Wevik and Buchholz are 100 percent vested in the plan.

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

The following table describes the potential payments and benefits under our compensation and benefit plans and arrangements to which our Named Executive Officers would be entitled upon termination of employment. Except for (i) certain terminations following a change in control ("CIC"), as described below, (ii) pro-rata payout of incentive compensation and the acceleration of vesting of equity awards upon retirement, death or disability, and (iii) certain pension and nonqualified deferred compensation arrangements described under Pension Benefits for 2020 and Nonqualified Deferred Compensation for 2020 above, there are no agreements, arrangements or plans that entitle the Named Executive Officers to severance, perquisites, or other enhanced benefits upon termination of their employment. Any agreements to provide other payments or benefits to a terminating executive officer would be in the discretion of the Compensation Committee.

The amounts shown below assume that such termination was effective as of December 31, 2020, and thus includes estimates of the amounts that would be paid out to our Named Executive Officers upon their termination. The table does not include amounts such as base salary, short-term incentives and stock awards that the Named Executive Officers earned due to employment through December 31, 2020 and distributions of vested benefits such as those described under Pension Benefits for 2020 and Nonqualified Deferred Compensation for 2020. The table also does not include a value for outplacement services because this would be a de minimis amount. The actual amounts to be paid can only be determined at the time of such Named Executive Officer's separation from us.

	Cash Severance Payment	Incremental Retirement Benefit (present value)(2)	Continuation of Medical/ Welfare Benefits (present value)(3)	Acceleration of Equity Awards(4)	Total Benefits
Linden R. Evans					
• Retirement	—	—	—	$365,147	$365,147
• Death or disability	—	—	—	$1,612,029	$1,612,029
• Involuntary termination	—	—	—	—	—
• CIC	—	—	—	$1,568,013	$1,568,013
• Involuntary or good reason termination after CIC(1)	$4,684,331	$1,611,600	$108,800	$1,568,013	$7,972,794
Richard W. Kinzley					
• Retirement	—	—	—	$122,815	$122,815
• Death or disability	—	—	—	$556,222	$556,222
• Involuntary termination	—	—	—	—	—
• CIC	—	—	—	$542,587	$542,587
• Involuntary or good reason termination after CIC(1)	$1,479,499	$471,933	$58,200	$542,587	$2,552,219
Brian G. Iverson					
• Retirement	—	—	—	$94,141	$94,141
• Death or disability	—	—	—	$431,993	$431,993
• Involuntary termination	—	—	—	—	—
• CIC	—	—	—	$421,339	$421,339
• Involuntary or good reason termination after CIC(1)	$1,229,334	$271,744	$39,600	$421,339	$1,962,018
Stuart A. Wevik					
• Retirement	—	—	—	$62,644	$62,644
• Death or disability	—	—	—	$379,849	$379,849
• Involuntary termination	—	—	—	—	—
• CIC	—	—	—	$370,736	$370,736
• Involuntary or good reason termination after CIC(1)	$1,355,243	$193,732	$48,800	$370,736	$1,968,511
Scott A. Buchholz					
• Retirement	—	—	—	$38,503	$38,503
• Death or disability	—	—	—	$242,702	$242,702
• Involuntary termination	—	—	—	—	—
• CIC	—	—	—	$237,192	$237,192
• Involuntary or good reason termination after CIC(1)	$1,054,000	$210,800	$53,500	$237,192	$1,555,492

(1) The amounts reflected for involuntary or good reason termination after a change in control include the benefits a Named Executive Officer would receive in the event of a change in control as a sole event without the involuntary or good reason termination.

(2) Assumes that in the event of a change in control, Mr. Evans will receive an additional three years of credited and vesting service and the other Named Executive Officers will receive an additional two years of credited and vesting service towards the benefit accrual under their applicable retirement plans. For Messrs. Evans, Kinzley, Iverson, Wevik and Buchholz, this would be the Retirement Contributions and Nonqualified Deferred Compensation contributions. In addition, Mr. Buchholz would also have a Pension Restoration Contribution. The benefits will immediately vest and payments will commence at the earliest eligible date unless the executive has

elected a later date for the nonqualified plans. Because our Named Executive Officers are age 55 or older, they are already retiree eligible.

(3) Welfare benefits include medical coverage, dental coverage, life insurance, short-term disability coverage and long-term disability coverage. The calculation assumes that the Named Executive Officer does not take employment with another employer following termination, elects continued welfare benefits until age 55 or, if later, the end of the two year benefit continuation period (three years for Mr. Evans) and elects retiree medical benefits thereafter. Retirement is assumed to occur at the earliest eligible date.

(4) In the event of death or disability, the acceleration of equity awards represents the acceleration of unvested restricted stock and the assumed payout of the pro-rata share of the performance shares for the January 1, 2019 to December 31, 2021 and January 1, 2020 to December 31, 2022 performance periods. In the event of retirement, all unvested restricted stock is forfeited and the acceleration of equity awards represents only the pro-rata share of the performance shares. We assumed a 68 percent payout of the performance shares for the January 1, 2019 to December 31, 2021 performance period and a 51 percent payout of target for the January 1, 2020 to December 31, 2022 performance period based on our Monte Carlo valuations at December 31, 2020.

In the event of a change in control or an involuntary or good reason termination after a change in control, the acceleration of equity awards represents the acceleration of unvested restricted stock and the payout of the pro-rata share of the performance shares calculated as if the performance period ended on December 31, 2020 for the January 1, 2019 to December 31, 2021, and January 1, 2020 to December 31, 2022 performance periods.

The valuation of the restricted stock was based upon the closing price of our common stock on December 31, 2020, and the valuation of the performance shares was based on the average closing price of our common stock for the last 20 trading days of 2020. Actual amounts to be paid out at the time of separation from us may vary significantly based upon the market value of our common stock at that time.

Payments Made Upon Termination. Regardless of the manner in which a Named Executive Officer's employment terminates, he or his beneficiaries may be entitled to receive amounts earned during his term of employment. These include:

- accrued salary and unused vacation pay;
- amounts vested under the Pension Plan and Nonqualified Pension Plans;
- amounts vested under the Nonqualified Deferred Compensation Plan; and
- amounts vested under the 401(k) Retirement Savings Plan.

Payments Made Upon Retirement. In the event of retirement of a Named Executive Officer, in addition to the items identified above, he will also receive the benefit of the following:

- a pro-rata share of the performance shares for each outstanding performance period upon completion of the performance period; and
- a pro-rata share of the actual payout under the Short-Term Incentive Plan upon completion of the incentive period.

Payments Made Upon Death or Disability. In the event of death or disability of a Named Executive Officer, in addition to the items identified above for payments made upon termination, he will also receive the benefit of the following:

- accelerated vesting of restricted stock and restricted stock units;
- a pro-rata share of the performance shares for each outstanding performance period upon completion of the performance period; and
- a pro-rata share of the actual payout under the Short-Term Incentive Plan upon completion of the incentive period.

Payments Made Upon a Change in Control. Our Named Executive Officers have change in control agreements that terminate November 15, 2022. The renewal of the change in control agreements is at the discretion of the Compensation Committee and the Board of Directors. The change in control agreements provide for certain payments and other benefits to be payable upon a change in control and a subsequent termination of employment, either involuntary or for a good reason. In order to receive any payments under the agreements, the Named Executive Officer must sign a waiver that includes a one-year non-competition clause and two-year non-solicitation and non-disparagement clauses.

A change in control is defined in the agreements as:

- an acquisition of 30 percent or more of our common stock, except for certain defined acquisitions, such as acquisition by employee benefit plans, us, any of our subsidiaries, or acquisition by an underwriter holding the securities in connection with a public offering thereof; or
- members of our incumbent Board of Directors cease to constitute at least two-thirds of the members of the Board of Directors, with the incumbent Board of Directors being defined as those individuals consisting of the Board of Directors on the date the agreement was executed and any other directors elected subsequently whose election was approved by the incumbent Board of Directors; or
- approval by our shareholders of:
  - a merger, consolidation, or reorganization;
  - liquidation or dissolution; or
  - an agreement for sale or other disposition of all or substantially all of our assets, with exceptions for transactions which do not involve an effective change in control of voting securities or Board of Directors membership, and transfers to subsidiaries or sale of subsidiaries; and
- all regulatory approvals required to effect a change in control have been obtained and the transaction constituting the change in control has been consummated.

In the change in control agreements, a good reason for termination that triggers payment of benefits includes:

- a material reduction of the executive's authority, duties or responsibilities;
- a reduction in the executive's annual compensation or any failure to pay the executive any compensation or benefits to which he or she is entitled within seven days of the date due;
- any material breach by us of any provisions of the change in control agreement;
- requiring the executive to be based outside a 50-mile radius from his or her usual and normal place of work; or
- our failure to obtain an agreement, satisfactory to the executive, from any successor company to assume and agree to perform under the change in control agreement.

Upon a change in control, Mr. Evans will have an employment contract for a three-year period and the other Named Executive Officers will have an employment contract for a two-year period. During this time, the executive will receive annual compensation at least equal to the highest rate in effect at any time during the one-year period preceding the change in control and will also receive employment welfare benefits, pension benefits and supplemental retirement benefits on a basis no less favorable than those received prior to the change in control. Annual compensation is defined to include amounts which are includable in the gross income of the executive for federal income tax purposes, including base salary, targeted short-term incentive, targeted long-term incentive grants and awards, and matching contributions or other benefits payable under the 401(k) Retirement Savings Plan, but exclude restricted stock awards, performance units or stock options that become vested or exercisable pursuant to a change in control.

If a Named Executive Officer's employment is terminated prior to the end of the covered time by us for cause or disability, by reason of the Named Executive Officer's death, or by the Named Executive Officer without good reason, the Named Executive Officer will receive all amounts of compensation earned or accrued through the termination date. If the Named Executive Officer's employment is terminated because of death or disability, the Named Executive Officer or his beneficiaries will also receive a pro rata bonus equal to 100 percent of the target incentive for the portion of the year served.

If Mr. Evans' employment is terminated during the employment term (other than by reason of death) (i) by us other than for cause or disability, or (ii) by Mr. Evans for a good reason, then Mr. Evans is entitled to the following benefits:

- all accrued compensation and a pro-rata bonus (the same as Mr. Evans or Mr. Evans' beneficiaries would receive in the event of death or disability discussed above);
- severance pay equal to 2.99 times Mr. Evans' severance compensation defined as his base salary and short-term incentive target on the date of the change in control; provided that if Mr. Evans has attained the age of 62 on the termination date, the severance payment will be adjusted for the ratio of the number of days remaining to his 65th birthday to 1,095 days;
- continuation of employee welfare benefits for three years following the termination date unless Mr. Evans becomes covered under the health insurance coverage of a subsequent employer which does not contain any exclusion or limitation with respect to any preexisting condition of Mr. Evans or his eligible dependents;

- following the three-year period, Mr. Evans may elect to receive coverage under the employee welfare plans of the successor entity at his then-current level of benefits (or reduced coverage at his election) by paying the premiums charged to regular full-time employees for such coverage, and is eligible to continue receiving such coverage through the date of his retirement;
- three additional years of service and age will be credited to Mr. Evans' retiree medical savings account and the account balance will become fully vested and he is eligible to use the account balance to offset retiree medical premiums at the later of age 55 or the end of the three year continuation period;
- three years of additional credited service under the Pension Restoration Plan and Pension Plan; and
- outplacement assistance services for up to six months.

If any other NEO's employment is terminated during the employment term (other than by death) (i) by us other than for cause or disability, or (ii) by the NEO for a good reason, then the NEO is entitled to the following benefits:

- all accrued compensation and a pro-rata bonus (the same as the NEO or the NEO's beneficiaries would receive in the event of death or disability discussed above);
- severance pay equal to two times the NEO's severance compensation defined as the NEO's base salary and short-term incentive target on the date of the change in control; provided that if the NEO has attained the age of 63 on the termination date, the severance payment shall be adjusted for the ratio of the number of days remaining to the NEO's 65th birthday to 730 days;
- continuation of employee welfare benefits for two years following the termination date unless the NEO becomes covered under the health insurance coverage of a subsequent employer which does not contain any exclusion or limitation with respect to any preexisting condition of the NEO or the NEO's eligible dependents;
- following the two-year period, the NEO may elect to receive coverage under the employee welfare plans of the successor entity at his then-current level of benefits (or reduced coverage at the NEO's election) by paying the premiums charged to regular full-time employees for such coverage, and is eligible to continue receiving such coverage through the date of his retirement;
- two additional years of service and age will be credited to the NEO's retiree medical savings account and the account balance will become fully vested and the NEO is eligible to use the account balance to offset retiree medical premiums at the later of age 55 or the end of the two year continuation period;
- two years of additional credited service under the executives' applicable retirement plans; and
- outplacement assistance services for up to six months.

The change in control agreements do not contain a benefit to cover any excise tax imposed by Section 4999 of the Internal Revenue Code of 1986. The executive must sign a waiver and release agreement in order to receive the severance payment.

PAY RATIO FOR 2020

We are providing the following information about the relationship of the annual total compensation of our employees and the annual total compensation of Mr. Evans, our Chief Executive Officer, in 2020.

Based on the information below for the fiscal year 2020 and calculated in a manner consistent with Item 402(u) of Regulation S-K, we reasonably estimate that the ratio of our CEO's annual total compensation to the annual total compensation of our median employee was 34:1.

Name	Year	Salary	Stock Awards	Non-Equity Incentive Plan Compensation	Change in Pension Value(2)	All Other Compensation(3)	Total
Linden R. Evans	2020	$783,333	$1,820,599	$936,632	$79,100	$601,450	$4,221,114
Median Employee(1)	2020	$87,308	$—	$7,319	$17,199	$12,538	$124,363

(1) We identified our median employee based on the year-to-date total cash compensation actually paid as of October 4, 2020 to all of our employees, other than our CEO, who were employed on October 4, 2020.

(2) See Note 4 to our Summary Compensation Table for a description of how the values in the Change in Pension Value column are calculated.

(3) All Other Compensation includes 401(k) match, defined contributions, NQDC contributions, dividends on restricted stock and other personal benefits for Mr. Evans and the 401(k) match, defined contributions, and vehicle compensation for the median employee.

PROPOSAL 3	**ADVISORY VOTE ON OUR EXECUTIVE COMPENSATION**

We are providing shareholders with an annual advisory, non-binding vote on the executive compensation of our Named Executive Officers (commonly referred to as “say on pay”). Accordingly, shareholders will vote on approval of the following resolution:

> RESOLVED, that the shareholders approve, on an advisory basis, the compensation of our Named Executive Officers as disclosed in the Compensation Discussion and Analysis section, the accompanying compensation tables and the related narrative disclosure in this proxy statement.

This vote is non-binding. The Board of Directors and the Compensation Committee expect to consider the outcome of the vote when considering future executive compensation decisions to the extent they can determine the cause or causes of any significant negative voting results. At our 2020 annual meeting, shareholders owning 97 percent of the shares that were voted in this matter approved our executive compensation.

As described at length in the Compensation Discussion and Analysis section of this proxy statement, we believe our executive compensation program is reasonable, competitive and strongly focused on pay for performance. The compensation of our Named Executive Officers varies depending upon the achievement of pre-established performance goals, both individual and corporate. Our short-term incentive is tied to earnings per share, safety performance targets, and employee wellness targets that reward our executives when they deliver targeted financial and safety results. Our long-term incentives are tied to market performance with 50 percent delivered in restricted stock and 50 percent delivered in performance shares. Entitlement to the performance shares is based on our total shareholder return over a three-year performance period compared to our Performance Peer Group. Through stock ownership guidelines, equity incentives and clawback provisions, we align the interests of our executives with those of our shareholders and our long-term interests. Our executive compensation policies have enabled us to attract and retain talented and experienced senior executives who can drive financial and strategic growth objectives that are intended to enhance shareholder value. We believe that the 2020 compensation of our Named Executive Officers was appropriate and aligned with our 2020 results and positions us for long-term growth.

Shareholders are encouraged to read the Compensation Discussion and Analysis, the accompanying compensation tables, and the related narrative disclosures to better understand the compensation of our Named Executive Officers.

The advisory resolution to approve executive compensation is non-binding. However, our Board of Directors will consider shareholders to have approved our executive compensation if the number of votes cast “For” the proposal exceeds the number of votes cast “Against” the proposal. Abstentions and broker non-votes will have no effect on such vote.

The Board of Directors recommends a vote *FOR* the advisory vote on executive compensation.

TRANSACTION OF OTHER BUSINESS

Our Board of Directors does not intend to present any business for action by our shareholders at the meeting except the matters referred to in this proxy statement. If any other matters should be properly presented at the meeting, it is the intention of the persons named in the accompanying form of proxy to vote thereon in accordance with the recommendations of our Board of Directors.

SHAREHOLDER PROPOSALS FOR 2022 ANNUAL MEETING

Shareholder proposals intended to be presented at our 2022 annual meeting of shareholders and considered for inclusion in our proxy materials must be received by our Corporate Secretary in writing at our executive offices at 7001 Mount Rushmore Road, P.O. Box 1400, Rapid City, South Dakota 57709, on or prior to November 18, 2021. Any proposal submitted must be in compliance with Rule 14a-8 of Regulation 14A of the Securities and Exchange Commission.

Additionally, a shareholder may submit a proposal or director nominee for consideration at our 2022 annual meeting of shareholders, but not for inclusion of the proposal or director nominee in our proxy materials, if the shareholder gives timely written notice of such proposal in accordance with Article I, Section 9 of our Bylaws. In general, Article I, Section 9 provides that, to be timely, a shareholder's notice must be delivered to our Corporate Secretary in writing not less than 90 days nor more than 120 days prior to the anniversary date of the immediately preceding annual meeting of shareholders.

Our 2021 annual meeting is scheduled for April 27, 2021. Ninety days prior to the first anniversary of this date will be January 27, 2022, and 120 days prior to the first anniversary of this date will be December 28, 2021. For business to be properly requested by the shareholder to be brought before the 2022 annual meeting of shareholders, the shareholder must comply with all of the requirements of Article I, Section 9 of our Bylaws, not just the timeliness requirements set forth above.

SHARED ADDRESS SHAREHOLDERS

In accordance with a notice sent to eligible shareholders who share a single address, we are sending only one annual report and proxy statement to that address unless we receive instructions to the contrary from any shareholder at that address. This practice, known as "householding," is designed to reduce our printing and postage costs. However, if a shareholder of record residing at such an address wishes to receive a separate annual report or proxy statement in the future, he or she may contact Shareholder Relations at the below address.

Shareholder Relations
Black Hills Corporation
7001 Mount Rushmore Road
P.O. Box 1400
Rapid City, SD 57709
(605) 721-1700

Eligible shareholders of record receiving multiple copies of our annual report and proxy statement can request householding by contacting us in the same manner. Shareholders who own shares through a bank, broker or other nominee can request householding by contacting the nominee.

We hereby undertake to deliver promptly, upon written or oral request, a separate copy of the annual report to shareholders, or proxy statement, as applicable, to our shareholders at a shared address to which a single copy of the document was delivered.

Please vote your shares by telephone, by the Internet or by promptly returning the accompanying form of proxy, whether or not you expect to be present at the annual meeting.

ANNUAL REPORT ON FORM 10-K

A copy of our Annual Report on Form 10-K (excluding exhibits) for the year ended December 31, 2020, which is required to be filed with the Securities and Exchange Commission, will be made available to shareholders to whom this proxy statement is mailed, without charge, upon written or oral request to Shareholder Relations, Black Hills Corporation, 7001 Mount Rushmore Road, P.O. Box 1400, Rapid City, SD 57709, Telephone Number: (605) 721-1700. Our Annual Report on Form 10-K also may be accessed through our website at www.blackhillscorp.com.

IMPORTANT NOTICE REGARDING THE AVAILABILITY OF PROXY MATERIALS FOR THE SHAREHOLDER MEETING TO BE HELD ON APRIL 27, 2021

Shareholders may view this proxy statement, our form of proxy and our 2020 Annual Report to Shareholders over the Internet by accessing our website at www.blackhillscorp.com. Information on our website does not constitute a part of this proxy statement.

By Order of the Board of Directors,

/s/ Amy K. Koenig
AMY K. KOENIG
Vice President - Governance, Corporate Secretary and Deputy General Counsel

Dated: March 18, 2021

APPENDIX A RECONCILIATION OF NON-GAAP FINANCIAL MEASURES

	Year Ended	
	Dec. 31, 2020	Dec. 31, 2019
EPS available for common stock (GAAP)	$ 3.65	$ 3.28
Adjustments:		
Impairment of investment	0.11	0.32
Total adjustments	0.11	0.32
Tax on adjustments:		
Impairment of investment	(0.03)	(0.07)
Total adjustments, net of tax	0.08	0.25
EPS available for common stock, as adjusted (Non-GAAP)	$ 3.73	$ 3.53

USE OF NON-GAAP FINANCIAL MEASURE

In addition to presenting our earnings information in conformity with Generally Accepted Accounting Principles (GAAP), the Company has provided non-GAAP earnings data reflecting adjustments for special items as specified in the Reconciliation of Non-GAAP Financial Measures table above. EPS from continuing operations, as adjusted, is defined as EPS from continuing operations adjusted for expenses and other items that the Company believes do not reflect the Company's core operating performance. The Company believes that non-GAAP financial measures are useful to investors because the items excluded are not indicative of the Company's continuing operating results. The Company's management uses these non-GAAP financial measures as an indicator for planning and forecasting future periods. These non-GAAP measures have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP. Our presentation of these non-GAAP financial measures should not be construed as an inference that our future results will be unaffected by other income and expenses that are unusual, non-routine or non-recurring.

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

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2020
Or

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

Commission File Number 001-31303

BLACK HILLS CORPORATION

Incorporated in South Dakota **IRS Identification Number 46-0458824**

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

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

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

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

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

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

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

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

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

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

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

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

The aggregate market value of the voting common equity held by non-affiliates of the registrant on the last business day of the registrant's most recently completed second fiscal quarter, June 30, 2020, was $3,528,768,075

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

Class	Outstanding at January 31, 2021
Common stock, $1.00 par value	62,794,490 shares

Documents Incorporated by Reference
Portions of the registrant's Definitive Proxy Statement being prepared for the solicitation of proxies in connection with the 2021 Annual Meeting of Stockholders to be held on April 27, 2021, are incorporated by reference in Part III of this Form 10-K.

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GLOSSARY OF TERMS AND ABBREVIATIONS

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

AC	Alternating Current
AFUDC	Allowance for Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income (Loss)
Aquila Transaction	Our July 14, 2008 acquisition of five utilities from Aquila, Inc.
APSC	Arkansas Public Service Commission
Arkansas Gas	Black Hills Energy Arkansas, Inc., an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Arkansas (doing business as Black Hills Energy).
ARO	Asset Retirement Obligations
ASC	Accounting Standards Codification
ASU	Accounting Standards Update as issued by the FASB
ATM	At-the-market equity offering program
Availability	The availability factor of a power plant is the percentage of the time that it is available to provide energy.
BHC	Black Hills Corporation; the Company
BHSC	Black Hills Service Company, LLC, a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
Black Hills Colorado IPP	Black Hills Colorado IPP, LLC, a 50.1% owned subsidiary of Black Hills Electric Generation
Black Hills Electric Generation	Black Hills Electric Generation, LLC, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings, providing wholesale electric capacity and energy primarily to our affiliate utilities.
Black Hills Energy	The name used to conduct the business of our utility companies
Black Hills Energy Services	Black Hills Energy Services Company, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas commodity supply for the Choice Gas Programs (doing business as Black Hills Energy).
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
BLM	United States Bureau of Land Management
Btu	British thermal unit
Busch Ranch I	The 29 MW wind farm near Pueblo, Colorado, jointly owned by Colorado Electric and Black Hills Electric Generation. Colorado Electric and Black Hills Electric Generation each have a 50% ownership interest in the wind farm.
Busch Ranch II	The 60 MW wind farm near Pueblo, Colorado owned by Black Hills Electric Generation to provide wind energy to Colorado Electric through a power purchase agreement expiring in November 2044.
CARES Act	Coronavirus Aid, Relief, and Economic Security Act, signed on March 27, 2020, which is a tax and spending package intended to provide additional economic relief and address the impact of the COVID-19 pandemic.
CFTC	United States Commodity Futures Trading Commission
Cheyenne Prairie	Cheyenne Prairie Generating Station 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, 95 MW unit that is jointly-owned by Wyoming Electric (40 MW) and South Dakota Electric (55 MW).
Chief Operating Decision Maker (CODM)	Chief Executive Officer
Choice Gas Program	Regulator approved programs in Wyoming and Nebraska that allow certain utility customers to select their natural gas commodity supplier, providing the unbundling of the commodity service from the distribution delivery service.
CIAC	Contribution in Aid of Construction
City of Cheyenne	Cheyenne, Wyoming

City of Colorado Springs	Colorado Springs, Colorado
City of Gillette	Gillette, Wyoming
Colorado Electric	Black Hills Colorado Electric, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings, providing electric service to customers in Colorado (doing business as Black Hills Energy).
Colorado Gas	Black Hills Colorado Gas, Inc., an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Colorado (doing business as Black Hills Energy).
Common Use System (CUS)	The Common Use System is a jointly operated transmission system we participate in with Basin Electric Power Cooperative and Powder River Energy Corporation. The Common Use System provides transmission service over these utilities' combined 230-kilovolt (kV) and limited 69-kV transmission facilities within areas of southwestern South Dakota and northeastern Wyoming.
Consolidated Indebtedness to Capitalization Ratio	Any Indebtedness outstanding at such time, divided by capital at such time. Capital being consolidated net-worth (excluding noncontrolling interest) plus consolidated indebtedness (including letters of credit and certain guarantees issued) as defined within the current Revolving Credit Facility.
Cooling Degree Day (CDD)	A cooling degree day is equivalent to each degree that the average of the high and low temperature for a day is above 65 degrees. The warmer the climate, the greater the number of cooling degree days. Cooling degree days are used in the utility industry to measure the relative warmth of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations.
Corriedale	The 52.5 MW wind farm near Cheyenne, Wyoming, jointly owned by South Dakota Electric and Wyoming Electric, serving as the dedicated wind energy supply to the Renewable Ready program.
COVID-19	The official name for the 2019 novel coronavirus disease announced on February 11, 2020, by the World Health Organization, that is causing a global pandemic.
CPCN	Certificate of Public Convenience and Necessity
CPP	Clean Power Plan
CP Program	Commercial Paper Program
CPUC	Colorado Public Utilities Commission
CT	Combustion Turbine
CTII	The 40 MW Gillette CT, a simple-cycle, gas-fired combustion turbine owned by the City of Gillette.
Cushion Gas	The portion of natural gas necessary to force saleable gas from a storage field into the transmission system and for system balancing, representing a permanent investment necessary to use storage facilities and maintain reliability.
CVA	Credit Valuation Adjustment
DC	Direct Current
Dividend payout ratio	Annual dividends paid on common stock divided by net income from continuing operations available for common stock
DRSPP	Dividend Reinvestment and Stock Purchase Plan
DSM	Demand Side Management
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu).
EBITDA	Earnings before interest, taxes, depreciation and amortization, a non-GAAP measurement
ECA	Energy Cost Adjustment is an adjustment that allows us to pass the prudently-incurred cost of fuel and purchased energy through to customers.
Economy Energy	Purchased energy that costs less than that produced with the utilities' owned generation.
EECR	Energy Efficiency Cost Recovery is an adjustment mechanism that allows us to recover from customers the costs associated with providing energy efficiency programs.
EIA	Environmental Improvement Adjustment is an annual adjustment mechanism that allows us to recover from customers eligible investments in, and expense related to, new environmental measures.
EPA	United States Environmental Protection Agency

Equity Unit	Each Equity Unit had a stated amount of $50, consisting of a purchase contract issued by BHC to purchase shares of BHC common stock and a 1/20, or 5% undivided beneficial ownership interest in $1,000 principal amount of BHC remarketable junior subordinated notes issued on November 23, 2015 and retired on August 17, 2018. On November 1, 2018, we completed settlement of the stock purchase contracts that are components of the Equity Units issued in November 2015.
EWG	Exempt Wholesale Generator
FASB	Financial Accounting Standards Board
FERC	United States Federal Energy Regulatory Commission
Fitch	Fitch Ratings Inc.
GAAP	Accounting principles generally accepted in the United States of America
GCA	Gas Cost Adjustment is an adjustment that allows us to pass the prudently-incurred cost of gas and certain services through to customers.
GHG	Greenhouse gases
Global Settlement	Settlement with a utility's commission where the revenue requirement is agreed upon, but the specific adjustments used by each party to arrive at the amount are not specified in public rate orders.
Happy Jack	Happy Jack Wind Farm, LLC, owned by Duke Energy Generation Services
Heating Degree Day (HDD)	A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the utility industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations.
HomeServe	We offer HomeServe products to our natural gas residential customers interested in purchasing additional home repair service plans.
ICFR	Internal Controls Over Financial Reporting
Iowa Gas	Black Hills Iowa Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Iowa (doing business as Black Hills Energy).
IPP	Independent Power Producer
IRC	Internal Revenue Code
IRS	United States Internal Revenue Service
ITC	Investment Tax Credit
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Kansas (doing business as Black Hills Energy).
kV	Kilovolt
LIBOR	London Interbank Offered Rate
Mcf	Thousand cubic feet
Mcfd	Thousand cubic feet per day
MDU	Montana-Dakota Utilities Co., a subsidiary of MDU Resources Group, Inc.
MEAN	Municipal Energy Agency of Nebraska
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MSHA	Mine Safety and Health Administration
MTPSC	Montana Public Service Commission
MW	Megawatts
MWh	Megawatt-hours
N/A	Not Applicable
NAV	Net Asset Value
Nebraska Gas	Black Hills Nebraska Gas, LLC, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Nebraska (doing business as Black Hills Energy).
Neil Simpson II	A mine-mouth, coal-fired power plant owned and operated by South Dakota Electric with a total capacity of 90 MW located at our Gillette, Wyoming energy complex.

NERC	North American Electric Reliability Corporation
NO_x	Nitrogen oxide
NOL	Net Operating Loss
NPSC	Nebraska Public Service Commission
NYSE	New York Stock Exchange
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
OSHA	Occupational Safety & Health Administration
OSM	United States Department of the Interior’s Office of Surface Mining
PacifiCorp	PacifiCorp, a wholly owned subsidiary of MidAmerican Energy Holdings Company, itself an affiliate of Berkshire Hathaway.
PCA	Power Cost Adjustment is an annual adjustment mechanism that allows us to pass a portion of prudently-incurred delivered power costs, including fuel, purchased capacity and energy, and transmission costs, through to customers.
PCCA	Power Capacity Cost Adjustment is an annual adjustment that allows us to pass the prudently-incurred purchased capacity costs, incremental to costs included in base rates, through to customers.
Peak View	The 60 MW wind farm owned by Colorado Electric.
PPA	Power Purchase Agreement
PRPA	Platte River Power Authority
PSA	Power Sales Agreement
Pueblo Airport Generation	The 420 MW combined cycle gas-fired power generation plants jointly owned by Colorado Electric (220 MW) and Black Hills Colorado IPP (200 MW). Black Hills Colorado IPP owns and operates this facility. The plants commenced operation on January 1, 2012.
PTC	Production Tax Credit
PUHCA 2005	Public Utility Holding Company Act of 2005
Ready	The Company’s branding platform which emphasizes that we will 1) prioritize our customers; 2) act as a thoughtful, responsible leader; 3) listen first and lead with a focus on relationships; and 4) be creative in our approach to solutions.
Renewable Advantage	The 200 MW solar facility project to be constructed in Pueblo County, Colorado. The project aims to lower customer energy costs and provide economic and environmental benefits to Colorado Electric’s customers and communities. This project, which was approved by the CPUC in September 2020, will be owned by a third-party renewable energy developer with Colorado Electric purchasing all of the energy generated at the facility under the terms of a 15-year PPA. The project is expected to be placed in service in 2023.
Renewable Ready	Voluntary renewable energy subscription program for large commercial, industrial and governmental agency customers in South Dakota and Wyoming.
RESA	Renewable Energy Standard Adjustment is an incremental retail rate limited to 2% for Colorado Electric customers that provides funding for renewable energy projects and programs to comply with Colorado’s Renewable Energy Standard.
Revolving Credit Facility	Our $750 million credit facility used to fund working capital needs, letters of credit and other corporate purposes, which was amended and restated on July 30, 2018, and now terminates on July 30, 2023.
RMNG	Rocky Mountain Natural Gas LLC, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas transmission and wholesale services in western Colorado (doing business as Black Hills Energy).
SDPUC	South Dakota Public Utilities Commission
SEC	United States Securities and Exchange Commission
Service Guard Comfort Plan	Appliance protection plan that provides home appliance repair services through on-going monthly service agreements to residential utility customers.
Silver Sage	Silver Sage Windpower, LLC, owned by Duke Energy Generation Services
SO_2	Sulfur dioxide
S&P	Standard & Poor’s, a division of The McGraw-Hill Companies, Inc.
SPP	Southwest Power Pool, Inc. which oversees the bulk electric grid and wholesale power market in the central United States

SourceGas Transaction	On February 12, 2016, Black Hills Utility Holdings acquired SourceGas pursuant to a purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, which included the assumption of $760 million in debt at closing.
South Dakota Electric	Black Hills Power, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation, providing electric service to customers in Montana, South Dakota and Wyoming (doing business as Black Hills Energy).
SSIR	System Safety and Integrity Rider
System Peak Demand	Represents the highest point of retail customer usage for a single hour.
TCA	Transmission Cost Adjustment is an annual adjustment mechanism that allows us to recover from customers eligible transmission investments prior to the next rate review.
TCJA	Tax Cuts and Jobs Act enacted on December 22, 2017
Tech Services	Non-regulated product lines delivered by our Utilities that 1) provide electrical system construction services to large industrial customers of our electric utilities, and 2) serve gas transportation customers throughout its service territory by constructing and maintaining customer-owned gas infrastructure facilities, typically through one-time contracts.
Top of Iowa	Northern Iowa Windpower, LLC, a 80 MW wind farm located near Joice, Iowa, owned by Black Hills Electric Generation and operated by a third-party. We sell the wind energy generated in the MISO market.
TFA	Transmission Facility Adjustment is an annual adjustment mechanism that allows us to recover charges for qualifying new and modified transmission facilities from customers.
Transmission Tie	South Dakota Electric owns 35% of a DC transmission tie that interconnects the Western and Eastern transmission grids, which are independently-operated transmission grids serving the western and eastern United States, respectively. Basin Electric Power Cooperative owns the remaining ownership percentage. This transmission tie allows us to buy and sell energy in the Eastern grid without having to isolate and physically reconnect load or generation between the two transmission grids, thus enhancing the reliability of our system. It accommodates scheduling transactions in both directions simultaneously, provides additional opportunities to sell excess generation or to make economic purchases to serve our native load and contract obligations, and enables us to take advantage of power price differentials between the two grids. The total transfer capacity of the tie is 400 MW, including 200 MW from West to East and 200 MW from East to West.
Utilities	Black Hills' Electric and Gas Utilities
VEBA	Voluntary Employee Benefit Association
VIE	Variable Interest Entity
WECC	Western Electricity Coordinating Council
Wind Capacity Factor	Measures the amount of electricity a wind turbine produces in a given time period relative to its maximum potential
Working Capacity	Total gas storage capacity minus cushion gas
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings, providing coal supply primarily to five on-site, mine-mouth generating facilities (doing business as Black Hills Energy).
Wygen I	A mine-mouth, coal-fired generating facility with a total capacity of 90 MW located at our Gillette, Wyoming energy complex. Black Hills Wyoming owns 76.5% of the facility and Municipal Energy Agency of Nebraska (MEAN) owns the remaining 23.5%.
Wygen II	A mine-mouth, coal-fired power plant owned by Wyoming Electric with a total capacity of 95 MW located at our Gillette, Wyoming energy complex.
Wygen III	A mine-mouth, coal-fired power plant operated by South Dakota Electric with a total capacity of 110 MW located at our Gillette, Wyoming energy complex. South Dakota Electric owns 52% of the power plant, MDU owns 25% and the City of Gillette owns the remaining 23%.
Wyodak Plant	The 362 MW mine-mouth, coal-fired generating facility near Gillette, Wyoming, jointly owned by PacifiCorp (80%) and South Dakota Electric (20%). Our WRDC mine supplies all of the fuel for the facility.
Wyoming Electric	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation, providing electric service to customers in the Cheyenne, Wyoming area (doing business as Black Hills Energy).
Wyoming Gas	Black Hills Wyoming Gas, LLC, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Wyoming (doing business as Black Hills Energy).

Website Access to Reports

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

Forward-Looking Information

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

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

Any forward-looking statement contained in this document speaks only as of the date on which the statement is made and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, such as the COVID-19 pandemic, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements in this Form 10-K, including statements contained within Item 1A - Risk Factors.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

History and Organization

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

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

Our Electric Utilities segment generates, transmits and distributes electricity to approximately 216,000 electric utility customers in Colorado, Montana, South Dakota and Wyoming. Our Electric Utilities own 992 MW of generation and 8,892 miles of electric transmission and distribution lines.

Our Gas Utilities segment serves approximately 1,083,000 natural gas utility customers in Arkansas, Colorado, Iowa, Kansas, Nebraska, and Wyoming. Our Gas Utilities own and operate 4,774 miles of intrastate gas transmission pipelines and 41,838 miles of gas distribution mains and service lines, seven natural gas storage sites, nearly 49,000 horsepower of compression and over 560 miles of gathering lines.

Our Power Generation segment produces electric power from its wind, natural gas and coal-fired generating plants and sells the electric capacity and energy primarily to our utilities under long-term contracts. Our Mining segment produces coal at our mine near Gillette, Wyoming, and sells and delivers primarily under long-term contracts to adjacent mine-mouth electric generation facilities owned by our Electric Utilities and Power Generation businesses.

Electric Utilities

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

	As of December 31,		
Customers at End of Year	2020	2019	2018
Residential	184,872	183,232	181,459
Commercial	30,225	29,921	29,299
Industrial	83	83	84
Other	1,017	1,024	1,030
Total Electric Customers at End of Year	216,197	214,260	211,872

	As of December 31,		
Customers at End of Year	2020	2019	2018
Colorado Electric	98,735	97,890	96,645
South Dakota Electric	73,700	73,052	72,533
Wyoming Electric	43,762	43,318	42,694
Total Electric Customers at End of Year	216,197	214,260	211,872

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

	System Peak Demand (in MW)					
	2020		2019		2018	
	Summer	Winter	Summer	Winter	Summer	Winter
Colorado Electric	401	297	422	297	413	313
South Dakota Electric	378	304	335	320	355	314
Wyoming Electric	271	246	265	247	254	238

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Regulated Power Plants. As of December 31, 2020, our Electric Utilities' ownership interests in electric generating plants were as follows:

Unit	**Fuel Type**	**Location**	**Ownership Interest %** [(d)]	**Owned Capacity (MW)**	**In Service Date**
Colorado Electric:					
Busch Ranch I [(a)]	Wind	Pueblo, Colorado	50%	14.5	2012
Peak View [(b)]	Wind	Pueblo, Colorado	100%	60.0	2016
Pueblo Airport Generation	Gas	Pueblo, Colorado	100%	180.0	2011
Pueblo Airport Generation CT	Gas	Pueblo, Colorado	100%	40.0	2016
AIP Diesel	Oil	Pueblo, Colorado	100%	10.0	2001
Diesel #1 and #3-5	Oil	Pueblo, Colorado	100%	8.0	1964
Diesel #1-5	Oil	Rocky Ford, Colorado	100%	10.0	1964
South Dakota Electric:					
Cheyenne Prairie	Gas	Cheyenne, Wyoming	58%	55.0	2014
Corriedale [(c)]	Wind	Cheyenne, Wyoming	62%	32.5	2020
Wygen III	Coal	Gillette, Wyoming	52%	57.2	2010
Neil Simpson II	Coal	Gillette, Wyoming	100%	90.0	1995
Wyodak Plant	Coal	Gillette, Wyoming	20%	72.4	1978
Neil Simpson CT	Gas	Gillette, Wyoming	100%	40.0	2000
Lange CT	Gas	Rapid City, South Dakota	100%	40.0	2002
Ben French Diesel #1-5	Oil	Rapid City, South Dakota	100%	10.0	1965
Ben French CTs #1-4	Gas/Oil	Rapid City, South Dakota	100%	80.0	1977-1979
Wyoming Electric:					
Cheyenne Prairie	Gas	Cheyenne, Wyoming	42%	40.0	2014
Cheyenne Prairie CT	Gas	Cheyenne, Wyoming	100%	37.0	2014
Corriedale [(c)]	Wind	Cheyenne, Wyoming	38%	20.0	2020
Wygen II	Coal	Gillette, Wyoming	100%	95.0	2008
Total MW Capacity				991.6	

(a) In 2013, Busch Ranch I was awarded a one-time cash grant in lieu of ITCs under the Section 1603 program created under the American Recovery and Reinvestment Act.
(b) The Peak View facility qualifies for PTCs at $25/MWh under IRC 45 during the 10-year period beginning November 2016. The PTCs for this facility flow back to customers through a rider mechanism as a reduction to Colorado Electric's margins.
(c) Corriedale was completed and placed in service on November 30, 2020. This facility qualifies for PTCs at $25/MWh under IRC 45 during the 10-year period beginning November 2020.
(d) Jointly owned facilities are discussed in Note 6 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

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

Power Supply	2020	2019	2018
Coal	32.7 %	30.1 %	32.1 %
Natural Gas and Diesel Oil [(a)]	8.4	8.2	6.1
Wind	3.8	3.2	3.4
Total Generated	44.9	41.5	41.6
Coal, Natural Gas, Oil and Other Market Purchases	43.3	52.5	52.4
Wind	11.8	6.0	6.0
Total Purchased	55.1	58.5	58.4
Total	100.0 %	100.0 %	100.0 %

(a) The diesel-fueled generating units are generally used as supplemental peaking units. Power generated from these units, as a percentage of total power supply, was 0.2%, 0.1% and 0.0% for the years ended December 31, 2020, 2019, and 2018, respectively.

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

Fuel and Purchased Power (dollars per MWh)	2020	2019	2018
Coal	$ 11.00	$ 11.46	$ 11.10
Natural Gas and Diesel Oil	21.67	28.26	34.07
Total Generated Weighted Average Fuel Cost	12.07	13.86	13.53
Coal, Natural Gas, Oil and Other Market Purchases	44.61	43.73	45.62
Wind Purchases	32.01	48.61	54.31
Total Purchased Power Weighted Average Cost	41.91	44.23	46.51
Total Weighted Average Fuel and Purchased Power Cost	$ 28.52	$ 31.62	$ 32.79

Power Purchase and Power Sales Agreements. We have executed various PPAs to support our Electric Utilities' capacity and energy needs beyond our regulated power plants' generation. Our Electric Utilities also have various long-term PSAs. Key contracts are disclosed in Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

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

At December 31, 2020, our Electric Utilities owned the electric transmission and distribution lines shown below:

Utility	State	Transmission [(a)] (in Line Miles)	Distribution (in Line Miles)
Colorado Electric	Colorado	572	3,135
South Dakota Electric	South Dakota, Wyoming	1,242	2,565
Wyoming Electric	Wyoming	58	1,320
		1,872	7,020

(a) Electric transmission line miles include voltages of 69 kV and above.

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

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

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

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

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

Subsidiary	Jurisdiction	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Authorized Capital Structure Debt/Equity	Authorized Rate Base (in millions)	Effective Date	Additional Tariffed Mechanisms	Percentage of Power Marketing Profit Shared with Customers
Colorado Electric (a)	CO	9.37%	7.43%	48%/52%	$539.6	1/2017	ECA, TCA, PCCA, EECR/ DSM, RESA	90%
	CO	9.37%	6.02%	67%/33%	$57.9	1/2017	Clean Air Clean Jobs Act Adjustment Rider	N/A
South Dakota Electric	WY	9.90%	8.13%	47%/53%	$46.8	10/2014	ECA	65%
	SD	Global Settlement	7.76%	Global Settlement	$543.9	10/2014	ECA, TFA, EIA	70%
	FERC	10.80%	8.76%	43%/57%	$154.0 (b)	2/2009	FERC Transmission Tariff	N/A
Wyoming Electric (a)	WY	9.90%	7.98%	46%/54%	$376.8	10/2014	PCA, EECR/DSM, Rate Base Recovery on Acquisition Adjustment	N/A

(a) For both Colorado Electric and Wyoming Electric, transmission investments are recovered through retail rates rather than FERC Transmission Tariffs.
(b) Includes $136.9 million in 2020 rate base for the 2020 Projected Common Use System formula rate that is updated annually and $17.1 million in rate base for the Transmission Tie that is based on the approved stated rate from 2005.

The regulatory provisions for recovering the costs to supply electricity vary by state. We have cost adjustment mechanisms for our Electric Utilities, subject to thresholds noted above, that allow us to pass the prudently-incurred cost of fuel and purchased power to customers. These mechanisms allow the utility operating in that state to collect, or refund the difference between the cost of commodities and certain services embedded in our base rates and the actual cost of the commodities and certain services without filing a general rate review. In addition, some states allow for recovery of new capital investment placed in service between base rate reviews through approved rider tariffs. These tariffs allow the utility a return on the investment.

A summary of mechanisms we have in place are shown in the table below:

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

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(a) South Dakota Electric's Environmental Cost (EIA) and Transmission Capital (TFA) tariffs were suspended for a six-year moratorium period effective July 1, 2017. On January 7, 2020, South Dakota Electric received approval from the SDPUC to extend the 6-year moratorium period by an additional 3 years whereby these recovery mechanisms will not be effective prior to July 1, 2026. For additional information, see Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K. On December 1, 2020, South Dakota Electric (SD) terminated its Energy Efficiency program.

(b) South Dakota Electric has an approved FERC Transmission Tariff based on a formulaic approach that determines the revenue component of South Dakota Electric's open access transmission tariff.

Tariff Filings. See Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for tariff filings and additional information regarding current electric regulatory activity.

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

Gas Utilities

We conduct natural gas utility operations through our Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming subsidiaries. Our Gas Utilities transport and distribute natural gas through our distribution network to approximately 1,083,000 customers. Additionally, we sell contractual pipeline capacity and gas commodities to other utilities and marketing companies, including our affiliates, on an as-available basis.

We also provide non-regulated services to our regulated customers. Black Hills Energy Services provides natural gas supply to approximately 52,000 retail distribution customers under the Choice Gas Program in Nebraska and Wyoming. Additionally, we provide services under the Service Guard Comfort Plan, Tech Services and HomeServe.

	As of December 31,		
Customers at End of Year	2020	2019	2018
Residential	844,999	831,351	821,624
Commercial	83,135	82,912	82,498
Industrial	2,235	2,208	2,221
Transportation	152,568	149,971	147,550
Total Natural Gas Customers at End of Year	1,082,937	1,066,442	1,053,893

	As of December 31,		
Customers at End of Year	2020	2019	2018
Arkansas	178,281	174,447	171,978
Colorado	197,817	191,950	186,759
Iowa	160,952	159,641	158,485
Kansas	116,973	115,846	114,840
Nebraska	296,778	293,576	291,723
Wyoming	132,136	130,982	130,108
Total Natural Gas Customers at End of Year	1,082,937	1,066,442	1,053,893

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

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

The following table summarizes certain information regarding our regulated underground gas storage facilities as of December 31, 2020:

State	Working Capacity (Mcf)	Cushion Gas (Mcf)	Total Capacity (Mcf)	Maximum Daily Withdrawal Capability (Mcfd)
Arkansas	8,442,700	13,149,040	21,591,740	196,000
Colorado	2,360,895	6,165,315	8,526,210	30,000
Wyoming	5,733,900	17,145,600	22,879,500	36,000
Total	16,537,495	36,459,955	52,997,450	262,000

The following table summarizes certain information regarding our system infrastructure as of December 31, 2020:

State	Intrastate Gas Transmission Pipelines (in line miles)	Gas Distribution Mains (in line miles)	Gas Distribution Service Lines (in line miles)
Arkansas	935	5,090	1,223
Colorado	693	6,879	2,618
Iowa	165	2,839	2,151
Kansas	330	2,961	1,366
Nebraska	1,312	8,739	3,252
Wyoming	1,339	3,495	1,225
Total	4,774	30,003	11,835

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

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

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

Our Gas Utilities are authorized to use natural gas cost recovery mechanisms allowing rate adjustments reflecting changes in the wholesale cost of natural gas and recovery of all the costs prudently incurred in purchasing gas for customers. In addition to natural gas cost recovery mechanisms, other recovery mechanisms, which vary by utility, allow us to recover certain costs or earn a return on capital investments, such as energy efficiency plan costs and system safety and integrity investments.

The following table provides regulatory information for each of our natural gas utilities:

Subsidiary	Jurisdic-tion	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Authorized Capital Structure Debt/Equity	Authorized Rate Base (in millions)	Effective Date	Additional Tariffed Mechanisms
Arkansas Gas	AR	9.61%	6.82% (a)	51%/49%	$451.5 (b)	10/2018	GCA, Main Replacement Program, At-Risk Meter Relocation Program, Legislative or Regulatory Mandated Expenditures, EECR, Weather Normalization Adjustment, Billing Determinant Adjustment
Colorado Gas	CO	9.20%	6.76%	50%/50%	$231.2	7/2020	GCA, EECR/DSM
RMNG	CO	9.90%	6.71%	53%/ 47%	$118.7	6/2018	System Safety Integrity Rider, Liquids/Off-system/ Market Center Services Revenue Sharing
Iowa Gas	IA	Global Settlement	Global Settlement	Global Settlement	$109.2	2/2011	GCA, EECR, Capital Infrastructure Automatic Adjustment Mechanism, Farm Tap Tracker Adjustment, Gas Supply Optimization revenue sharing
Kansas Gas	KS	Global Settlement	Global Settlement	Global Settlement	$127.9	1/2015	GCA, Weather Normalization Tariff, Gas System Reliability Surcharge, Ad Valorem Tax Surcharge, Cost of Bad Debt Collected through GCA, Pension Levelized Adjustment
Nebraska Gas (c) (d)	NE	9.50%	6.71%	50%/50%	$504.2	3/2021	GCA, Cost of Bad Debt Collected through GCA, Infrastructure System Replacement Cost Recovery Surcharge, Choice Gas Program, System Safety and Integrity Rider, Bad Debt expense recovered through Choice Supplier Fee
Wyoming Gas (d)	WY	9.40%	6.98%	50%/50%	$354.4	3/2020	GCA, EECR, Rate Base Recovery on Acquisition Adjustment, Wyoming Integrity Rider, Choice Gas Program

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(a) Arkansas Gas return on rate base is adjusted to remove current liabilities from rate review capital structure for comparison with other subsidiaries.
(b) Arkansas Gas rate base is adjusted to include current liabilities for comparison with other subsidiaries.
(c) Information above reflects the NPSC order received on January 26, 2021. For additional information, see Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.
(d) The Choice Gas Program mechanisms are applicable to only a portion of Nebraska Gas and Wyoming Gas customers.

All of our Gas Utilities, except where the Choice Gas Program is the only option, have GCAs that allow us to pass the prudently-incurred cost of gas and certain services through to the customer between rate reviews. Some of the mechanisms we have in place include the following:

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

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(a) RMNG, which is an intrastate transmission pipeline that provides natural gas transmission and wholesale services in western Colorado, has an SSIR recovery mechanism. The other cost recovery mechanisms are not applicable to RMNG.

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

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

Utility Regulation Characteristics

State Renewable Energy Standards

Certain states where we conduct electric utility operations have adopted renewable energy portfolio standards that require or encourage our Electric Utilities to source, by a certain future date, a minimum percentage of the electricity delivered to customers from renewable energy generation facilities. As of December 31, 2020, we were subject to the following renewable energy portfolio standards or objectives:

- Colorado. Colorado adopted a renewable energy standard in 2004 that has two components: (i) electric resource standards and (ii) a 2% maximum annual retail rate impact for compliance with the electric resource standards. The electric resource standards require our Colorado Electric subsidiary to generate, or cause to be generated, electricity from renewable energy sources equaling: (i) 20% of retail sales from 2015 to 2019; and (ii) 30% of retail sales by 2020. Of these amounts, 3% must be generated from distributed generation sources with one-half of these resources being located at customer facilities. The net annual incremental retail rate impact for these renewable resource acquisitions (as compared to non-renewable resources) is limited to 2%. The standard encourages the CPUC to consider earlier and timely cost recovery for utility investment in renewable resources, including the use of a forward rider mechanism. We have been and currently remain in compliance with these standards.

  In 2019, the State of Colorado approved Senate Bill 236, which required qualified retail electric utilities (more than 500,000 customers) to submit a Clean Energy Plan to meet an 80% carbon reduction goal by 2030 based upon 2005 baseline levels. While Colorado Electric is not required to submit a Clean Energy Plan, the state also passed House Bill 1261 which established state-wide emission goals for greenhouse gas emitting activities that apply to Colorado Electric. Both House Bill 1261 and Senate Bill 236 include provisions that allow Colorado Electric to submit a voluntary Clean Energy Plan with a goal of 80% reduction by 2030. On January 7, 2021, Colorado Electric announced it will file a Clean Energy Plan with the CPUC voluntarily in 2022.

  On September 23, 2020, Colorado Electric received approval from the CPUC for its preferred solar bid request 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, which will contribute towards the aforementioned 80% carbon reduction goal by 2030. When Renewable Advantage comes online in 2023, more than half of Colorado Electric's generation mix will be renewable sources, leading to an approximate 70% reduction in GHG emissions by 2024.

- South Dakota. South Dakota adopted a renewable portfolio objective in 2008 that encourages, but does not mandate utilities to generate, or cause to be generated, at least 10% of their retail electricity supply from renewable energy sources by 2015.

- Wyoming. Wyoming currently has not issued a renewable energy portfolio standard.

In November 2020, we announced clean energy goals to reduce GHG emissions that are based on prudent and proven solutions to reduce our emissions while minimizing cost impacts to our customers. See more information in the Key Elements of our Business Strategy within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K.

Federal Regulation

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

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

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

The Federal Power Act authorizes FERC to certify and oversee a national electric reliability organization with authority to promulgate and enforce mandatory reliability standards applicable to all users, owners and operators of the bulk-power system. FERC has certified NERC as the electric reliability organization. NERC has promulgated mandatory reliability standards and NERC, in conjunction with regional reliability organizations that operate under FERC's and NERC's authority and oversight, enforces those mandatory reliability standards.

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

Power Generation

Our Power Generation segment, which operates through Black Hills Electric Generation and its subsidiaries, acquires, develops, constructs and operates our non-regulated power plants. As of December 31, 2020, we held varying interests in independent power plants with a total net ownership of 423 MW.

We produce electric power from our generating facilities and sell the electric capacity and energy, primarily to affiliates under a combination of mid- to long-term contracts, which mitigates the impacts of volatility in future power prices and fluctuations in demand.

As of December 31, 2020, the power plant ownership interests held by our Power Generation segment include:

Power Plants	Fuel Type	Location	Ownership Interest % [d]	Owned Capacity (MW)	In Service Date
Wygen I	Coal	Gillette, Wyoming	76.5%	68.9	2003
Pueblo Airport Generation [a]	Gas	Pueblo, Colorado	50.1%	200.0	2012
Busch Ranch I [b]	Wind	Pueblo, Colorado	50.0%	14.5	2012
Busch Ranch II [c]	Wind	Pueblo, Colorado	100.0%	60.0	2019
Top of Iowa [c]	Wind	Joice, Iowa	100.0%	80.0	2019
				423.4	

(a) In 2016, Black Hills Electric Generation sold a 49.9% noncontrolling interest in Black Hills Colorado IPP to a third party. See Note 14 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.
(b) In 2013, Busch Ranch I was awarded a one-time cash grant in lieu of ITCs under the Section 1603 program created under the American Recovery and Reinvestment Act.
(c) The Busch Ranch II and Top of Iowa facilities qualify for PTCs at $25/MWh under IRC 45 during the 10-year period beginning on the date each facility was originally placed in service.
(d) Jointly owned facilities are discussed in Note 6 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Power Sales Agreements and Operating Agreements. Our Power Generation facilities have various mid- to long-term power sales agreements and operating agreements. Key contracts are disclosed in Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Competition. The independent power industry consists of many strong and capable competitors, some of which may have more extensive operations or greater financial resources than we possess.

With respect to the merchant power sector, FERC has taken steps to increase access to the national transmission grid by utility and non-utility purchasers and sellers of electricity and foster competition within the wholesale electricity markets. Our Power Generation business could face greater competition if utilities are permitted to robustly invest in power generation assets. Conversely, state regulatory rules requiring utilities to competitively bid generation resources may provide opportunity for IPPs in some regions. To date, these initiatives have not had a material impact on our Power Generation segment.

The Energy Policy Act of 1992 and Public Utility Holding Company Act of 2005 (PUHCA 2005). PUHCA 2005 reiterated the definition and benefits of Exempt Wholesale Generator (EWG) status. Under PUHCA 2005, an EWG is an entity or generator engaged, directly or indirectly through one or more affiliates, exclusively in the business of owning, operating or both owning and operating all or part of one or more eligible facilities and selling electric energy at wholesale. Though EWGs are public utilities within the definition set forth in the Federal Power Act and are subject to FERC regulation of rates and charges, they are exempt from other FERC requirements. Through its subsidiaries, Black Hills Corporation is affiliated with three EWGs, Wygen I, Pueblo Airport Generating and Top of Iowa. Each of these three EWG's have been granted market-based rate authority.

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

Mining

Our Mining segment operates a single coal mine through our WRDC subsidiary. We surface mine, process and sell low-sulfur sub-bituminous coal at our mine near Gillette, Wyoming. The WRDC mine, which we acquired in 1956 from Homestake Mining Company, is located in the Powder River Basin. We produced approximately 3.7 million tons of coal in 2020.

During our surface mining operations, we strip and store the topsoil. We then remove the overburden (earth and rock covering the coal) with heavy equipment. Removal of the overburden typically requires drilling and blasting. Once the coal is exposed, we drill, fracture and systematically remove it, using front-end loaders and conveyors to transport the coal to the mine-mouth generating facilities. We reclaim disturbed areas as part of our normal mining activities by back-filling the pit with overburden removed during the mining process. Once we have replaced the overburden and topsoil, we reestablish vegetation and plant life in accordance with our approved post-mining topography plan.

In a basin characterized by thick coal seams, our overburden ratio, a comparison of the cubic yards of dirt removed to a ton of coal uncovered, has trended upwards over the last fifteen years. However, the overburden ratio at December 31, 2020 was 2.17 which decreased from 2.30 in the prior year as we mined in areas with lower overburden. We expect our stripping ratio to increase to approximately 2.27 by the end of 2021 as we mine in areas with higher overburden.

Mining rights to the reserves are based on three federal leases and one state lease. The federal leases expire between March 31, 2021 and September 30, 2025 and the state lease expires on August 1, 2023. The duration of the leases varies; however, the lease terms generally are extended to the exhaustion of economically recoverable reserves, as long as active mining continues. The federal lease expiring March 31, 2021 relates to an area we are no longer mining and will not be renewed. The Biden Administration recently issued an executive order that suspends new oil and gas leases on federal lands and eliminates fossil fuel subsidies. However, this moratorium does not apply to federal mining leases and we have not received federal subsidies.

We pay federal and state royalties of 12.5% of the selling price of all coal. As of December 31, 2020, we estimated our recoverable reserves to be approximately 182 million tons, based on a life-of-mine engineering study utilizing currently available drilling data and geological information prepared by internal engineering studies. The recoverable reserve life is equal to approximately 49 years at the current production levels. Our recoverable reserve estimates are periodically updated to reflect past production and other geological and mining data. Changes in mining methods or the utilization of new technologies may increase or decrease the recovery basis for a coal seam. Our recoverable reserves include reserves that can be economically and legally extracted at the time of their determination.

Substantially all of the mine's production is currently sold under contracts to:

- South Dakota Electric for use at the 90 MW Neil Simpson II plant to which we sell approximately 500,000 tons each year. This contract is for the life of the plant;

- Wyoming Electric for use at the 95 MW Wygen II plant to which we sell approximately 550,000 tons each year. This contract is for the life of the plant;

- The 362 MW Wyodak Plant owned 80% by PacifiCorp and 20% by South Dakota Electric. PacifiCorp is obligated to purchase a minimum of 1.5 million tons each year, subject to adjustments for planned outages and other contract terms. This contract expires December 31, 2022 and negotiations to extend the contract are ongoing. South Dakota Electric is also obligated to purchase a minimum of 375,000 tons per year for its 20% share of the power plant, subject to adjustments for planned outages and other contract terms;

- The 110 MW Wygen III power plant jointly owned 52% by South Dakota Electric, 25% by MDU and 23% by the City of Gillette to which we sell approximately 600,000 tons each year;

- The 90 MW Wygen I power plant jointly owned 76.5% by Black Hills Wyoming and 23.5% by MEAN to which we sell approximately 500,000 tons each year; and

- Certain regional industrial customers served by truck to which we sell a total of approximately 300,000 tons each year. These contracts have terms of one to five years.

Our Mining segment sells coal to South Dakota Electric and Wyoming Electric for all of their requirements under cost-based agreements that regulate earnings from these affiliate sales to a specified return on our mine's cost-depreciated investment base. The return calculated annually is 400 basis points above Moody's A-Rated Utility Bond Index applied to our Mining investment base.

The price of unprocessed coal sold to PacifiCorp for the Wyodak Plant is determined by the supply agreement described above. The agreement included a price adjustment in 2019. The price adjustment essentially allowed us to retain the full economic advantage of the mine's location adjacent to the plant. The price adjustment was based on market price plus considerations for the avoided costs of rail transportation and an unloading facility, which PacifiCorp would have to incur if it purchased from another mine. In addition, the agreement also provided for the monthly escalation of price based on an escalation factor.

In October 2019, negotiations were completed for the price re-opener in the contract with the Wyodak Plant. The new price was reset at $17.94 per ton effective July 1, 2019, compared to the prior contract price of $18.25 per ton. The current contract price is comprised of three components: 1) avoided transportation costs (approximately 20% of current price); 2) avoided costs of an unloading facility (approximately 30% of current price); and 3) a rolling 12-month average of the Coal Daily spot market price of 8,400 Btu Powder River Basin coal (approximately 50% of current price).

WRDC supplies coal to Black Hills Wyoming for the Wygen I generating facility for requirements under an agreement through June 30, 2038. Currently, this agreement uses a base price that includes price escalators and quality adjustments and includes actual cost per ton plus a margin equal to the yield for Moody's A-Rated Utility Bond Index plus 400 basis points with the base price being adjusted on a 5-year interval. Effective January 1, 2022, in conjunction with the new Wygen I 60 MW PPA, WRDC's current coal supply agreement will be revised using pricing that will be cost-based to regulate earnings to a specified return on the cost-depreciated investment base. For additional information regarding the new Wygen I 60 MW PPA, see Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Competition. Our strategy is to sell the majority of our production to on-site, mine-mouth generation facilities under long-term supply contracts. Historically, any off-site sales have been to consumers within close proximity to the WRDC mine. Rail transport market opportunities for WRDC are limited due to the lower heating value (Btu) of the coal, combined with the fact that the WRDC mine is served by only one railroad, resulting in less competitive transportation rates.

Additionally, coal competes with other energy sources, such as natural gas, wind, solar and hydropower. Costs and other factors relating to these alternative fuels, such as safety, environmental and availability considerations affect the overall demand for coal as a fuel.

Environmental Matters. We are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal health and safety regulations; and state hazard communication standards. See Environmental Matters section for further information.

Mine Reclamation. Reclamation is completed during production and after mining has finished. Under applicable law, we must submit applications to, and receive approval from, the Wyoming Department of Environmental Quality for any mining and reclamation plans that provide for orderly mining, reclamation and restoration of the WRDC mine. We have approved mining permits and are in compliance with other permitting programs administered by various regulatory agencies. The WRDC mine is permitted to operate under a five-year mining permit issued by the State of Wyoming. In 2016, that five-year permit was re-issued and we are currently in the process of renewing this permit. Based on extensive reclamation studies, we have accrued approximately $13 million for reclamation costs as of December 31, 2020. See additional information in Note 7 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

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

Environmental Matters

In November 2020, we announced clean energy goals to reduce GHG emissions that are based on prudent and proven solutions to reduce our emissions while minimizing cost impacts to our customers. See more information in Key Elements of our Business Strategy within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K.

Environmental Management System (EMS). We operate an EMS that is composed of environmental policies and procedures, voluntary initiatives, objectives and annual targets, operational controls, training, a sophisticated task scheduling/tracking and document control system, and a continuous improvement process. The program attained Colorado's highest level in their Environmental Leadership Program (Gold Level status in 2014) and has continued this status through 2020.

Methane Rules (Greenhouse Gas Emissions). The EPA and the State of Colorado have implemented strict regulatory requirements on hydrocarbon and methane emissions associated with natural gas gathering and transmission systems. Presently, we have facilities in our natural gas transmission operations affected by the methane reduction rules.

Our operations are in compliance with both EPA and State of Colorado rules. Future modifications to our gathering and transmissions systems are anticipated to trigger EPA methane rules that we will adhere to. We developed a corporate-wide methane control strategy to address GHG emissions. As a proactive measure in reducing methane emissions beyond current regulatory requirements, we have entered into the EPA's Methane Challenge Program. This is a voluntary program founded by the EPA in collaboration with oil and natural gas companies that recognizes companies that make specific and transparent commitments to reduce methane emissions.

Short-term Emission Limits. The EPA and State Air Quality Programs implemented short-term emission limits for coal and natural gas-fired generating units during normal and start-up operating scenarios for SO2, NOx and opacity. The limits pertain to emissions during start-up periods and upset conditions such as mechanical malfunctions. State and federal regulatory agencies typically excuse short-term emissions exceedances if they are reported and corrected immediately or if it occurs during start-up.

We proactively manage this requirement through maintenance efforts and installing additional pollution control systems to control SO2 emission short-term excursions during start-up. These actions have nearly eliminated our short-term emission limit compliance risk while plant availability remained above 90% for all four of our coal-fired plants. To eliminate the remaining potential for exceedances, an innovative trip logic mechanism was implemented to shut down the power plant if we anticipate the emission limit will be exceeded. There have been limited instances of the trip logic mechanism being used and we experienced zero exceedances during 2020.

Regional Haze (Impacts to the Wyodak Plant). The EPA Regional Haze rule was promulgated to improve visibility in our National Parks and Wilderness Areas. The State of Wyoming proposed controls in its Regional Haze State Implementation Plan (SIP) which allowed PacifiCorp to install low-NO_x burners in the Wyodak Plant, of which South Dakota Electric owns 20%. The EPA did not agree with the State of Wyoming's determination, overruled it in a Federal Implementation Plan (FIP) and proposed a Selective Catalytic Reactor to be installed to control NO_x emissions. This would cost South Dakota Electric approximately $27 million due to its 20% ownership of the Wyodak Plant. PacifiCorp and the State of Wyoming challenged the EPA's determination. Prior to proceeding to court, PacifiCorp and the EPA reached a verbal agreement on December 16, 2020, to limit operating hours and determined that low-NO_x burners would be considered appropriate to control NO_x emissions. This proposed agreement was published in the Federal Register, but remains in the public comment period until March 1, 2021. The final agreement must be published in the Federal Register and approved in Wyoming's State Implementation Plan through the rule making process.

Mining. Operations at the WRDC mine must regularly address issues related to the proximity of the mine disturbance boundary to the City of Gillette and to residential properties. Homeowner complaints and challenges to the permits may occur as mining operations move closer to residential areas. Specific concerns could include damage to wells, fugitive dust emissions, vibration and an emissions cloud from blasting. The mine makes every effort to reduce these impacts by monitoring blasts, modifying blast techniques to reduce blast vibration, applying dust suppression controls on roads and reclaiming lands to reduce windblown dust.

Former Manufactured Gas Plants (FMGP). Federal and state laws authorize the EPA and other agencies to issue orders compelling potentially responsible parties to clean up sites that are determined to present an actual or potential threat to human health or the environment. As of December 31, 2020, our Gas Utilities have two active FMGP sites, which are located in Council Bluffs, Iowa, and McCook, Nebraska. At the Council Bluffs site, the EPA issued an order for the responsible parties to proceed with an Engineering Evaluation and Cost Analysis (EECA) to clean up the site. Three viable Potential Responsible Parties (PRP) continue to deny their legal attachment to the site. The Company will continue conducting the EECA and anticipates pursuing the PRP's through legal action. There is currently no action being taken at the McCook, Nebraska site. A third-party initially indicated they intend to manage and pay for the clean-up at this site. However, after further investigation, the third-party assessed they owned the property after the gas plant ceased operations. We expect to conduct an assessment to determine viable PRPs.

For additional information, see Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Affordable Clean Energy Rule. The EPA was directed to repeal, revise and replace the Clean Power Plan rule. On August 31, 2018, the EPA published the proposed Affordable Clean Energy (ACE) rule. This rule focused on heat-rate improvements on coal-fired boiler units and applied only to our coal-fired plants. The Company's coal-fired plants subject to the rule had implemented or planned to implement a majority of the efficiency requirements listed in the rule. On January 19, 2021, a three-judge panel of the U.S. Court of Appeals for the District of Columbia Circuit vacated the ACE rule. The court remanded the regulation regarding carbon dioxide emissions from existing power plants back to the EPA for reconsideration. Currently, there is no rule governing power plant GHG emissions and it is uncertain when a new rule will be promulgated.

OSM Coal Combustion Residual Rule (CCR). The EPA issued the CCR which is currently effective and establishes requirements to protect surface and groundwater from impacts of coal ash impoundments. WRDC is exempt from the EPA CCR because ash is used for backfill reclamation in areas previously mined. The Office of Surface Mining (OSM) was considering CCR rules that would apply to the mine, but these rules were not proposed during the Trump administration. We will continue to monitor to see if the Biden administration pursues these rules.

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

Other Properties

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

Human Capital Resources

Overview

Black Hills Corporation is committed to supporting operational excellence by attracting, motivating, retaining and encouraging the development of highly qualified employees. Our employees' drive and dedication to their work, and their commitment to the safety of our customers and their fellow employees, allows Black Hills Corporation to successfully grow and manage our business year over year. The impacts of COVID-19 to our businesses and employees are discussed in the Company Highlights within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K.

Our Team	As of December 31, 2020
Total employees	3,011
Gender diversity (women as a % of total employees)	26%
Women in executive leadership positions (a)	31%
Ethnic diversity (non-white employees as a % of total)	11%
Military veterans	16%
Represented by a union	25%
	For the year ended December 31, 2020
Number of external hires	299
External hires gender diversity (as a % of total external hires)	29%
External hires ethnic diversity (as a % of total external hires)	16%
Turnover rate (b)	8%
Retirement rate	3%

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

Total Employees

	Number of Employees At December 31, 2020
Electric Utilities	379
Gas Utilities	1,237
Power Generation and Mining	60
Corporate and Other	1,335
Total	3,011

At December 31, 2020, approximately 21% of our total employees and 23% of our Electric and Gas Utilities employees were eligible for regular (age 65 with at least 5 years of service) or early (ages 55 to 64 with at least 5 years of service) retirement.

Collective Bargaining Agreements

At December 31, 2020, certain employees of our Electric Utilities and Gas Utilities were covered by the collective bargaining agreements as shown in the table below. We have not experienced any labor stoppages in decades.

Utility	Number of Employees	Union Affiliation	Expiration Date of Collective Bargaining Agreement
Colorado Electric	95	IBEW Local 667	April 15, 2023
South Dakota Electric	137	IBEW Local 1250	March 31, 2022
Wyoming Electric	26	IBEW Local 111	June 30, 2024
Total Electric Utilities	258		
Iowa Gas	121	IBEW Local 204	January 31, 2026
Kansas Gas	17	Communications Workers of America, AFL-CIO Local 6407	December 31, 2024
Nebraska Gas	100	IBEW Local 244	March 13, 2022
Nebraska Gas	147	CWA Local 7476	October 30, 2023
Wyoming Gas	15	IBEW Local 111	June 30, 2024
Wyoming Gas	84	CWA Local 7476	October 30, 2023
Total Gas Utilities	484		
Total	742		

Attraction

Continuous attraction of qualified team members is critical to our ability to serve our 1.3 million customers safely and efficiently. We actively recruit diverse candidates and continuously evaluate our interviewing and hiring practices to ensure equitable pay and processes. Our attraction efforts include the use of multiple nation-wide job boards, local college and high school outreach programs, a strong college internship program and participation in national and local job fairs. Another key area of attraction is our commitment to our military personnel and veterans. We have targeted attraction efforts specific to military personnel transitioning into civilian life and for veterans of all types.

Diversity & Inclusion

At Black Hills Corporation, we believe in the benefits of diversity, equity and inclusion. We believe that a diverse workforce will assist us in achieving our goals of becoming the safest utility in the nation, providing exceptional customer service and achieving new levels of growth in a rapidly evolving industry. Workforce diversity trends, including diverse new hires, promotions and turnover, are monitored at regular intervals.

Development and Retention

Retaining and developing team members is critical to our continued success. Our retention efforts include competitive compensation programs, career development resources for all employees and internal training programs. Our compensation programs are designed to be strategically aligned, externally competitive, internally equitable, personally motivating, cost effective and legally compliant. Our career development resources include management onboarding, leadership development programs, mentoring programs, individual development assessments and more. Internal training opportunities include corporate-wide trainings such as our code of conduct and specialized training opportunities for different job functions. Our Field Career Path Program (FCPP) promotes career growth through established standards of knowledge, skills, abilities and performance.

ITEM 1A. RISK FACTORS

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

STRATEGIC RISKS

Our continued success is dependent on execution of our strategic business plans including our growth strategy.

Our success depends, in significant part, on our ability to execute our strategic business plans, including our growth strategy. Our plans and strategy include reducing GHG emissions for our Electric Utilities and Gas Utilities, transforming the customer experience, growing our electric and natural gas customer load, pursuing operating efficiencies and modernizing our utility infrastructure. Our current plans and strategy may be negatively impacted by disruptive forces and innovations in the marketplace, changing political, business or regulatory conditions, and technology advancements.

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

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

Customer growth and usage in our service territories may fluctuate with economic conditions, emerging technologies or responses to price increases.

Our financial operating results are impacted by energy demand in our service territories. Customer growth and usage may be impacted by a number of factors, including the voluntary reduction in consumption of electricity and natural gas by our customers in response to increases in prices and energy efficiency programs, electrification initiatives that could negatively impact the demand for natural gas, economic conditions impacting customers' disposable income and the use of distributed generation resources or other emerging technologies. Continued technological improvements may make customer and third-party distributed generation and energy storage systems, including fuel cells, micro-turbines, wind turbines, solar cells and batteries, more cost effective and feasible for our customers. If more customers utilize their own generation, demand for energy from us would decline. Such developments could affect the price of energy and delivery of energy, require further improvements to our distribution systems to address changing load demands and could make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. Each of these factors could materially affect our financial operating results including earnings, cash flow and liquidity.

REGULATORY, LEGISLATIVE AND LEGAL RISKS

We may be subject to future laws, regulations, or actions associated with climate change, including those relating to fossil-fuel generation and GHG emissions, which could increase our operating costs or restrict our market opportunities.

We own and operate regulated and unregulated electric power plants that burn fossil fuels (natural gas and coal) and a surface mine that extracts and sells coal. We also purchase, store and deliver natural gas to our customers. These business activities are subject to evolving public concern regarding fossil fuels, GHG emissions (such as carbon dioxide and methane) and their impact on the climate.

There is uncertainty surrounding climate regulation due to legal challenges to some current regulations and anticipated new federal and/or state climate legislation and regulation. The Biden administration has issued executive orders aimed at reducing GHG emissions and declared climate change a national security policy for the first time. New or more stringent regulations or other energy efficiency requirements could require us to incur significant additional costs relating to, among other things, the installation of additional emission control equipment, the acceleration of capital expenditures, the purchase of additional emissions allowances or offsets, the acquisition or development of additional energy supply from renewable resources, the closure or capacity reductions of coal-fired power generation facilities and potential increased production from our combined cycle natural gas-fired generating units. Increased rules and regulations associated with fossil fuels and GHG emissions could result in the impairment or retirement of some of our existing or future transmission, distribution, generation and natural gas storage facilities or our coal mine. Further, these rules could create the need to purchase or build clean-energy fuel sources to fulfill obligations to our customers. These actions could also result in increased operating costs which could adversely impact customers and our financial operating results including earnings, cash flow and liquidity. We cannot definitively estimate the effect of GHG legislation or regulation on our results of operations, financial condition or cash flows.

Future GHG constraints designed to minimize emissions from natural gas could likewise result in increased costs and affect the demand for natural gas as well as the prices charged to customers and the competitive position of natural gas. Certain cities in our operational footprint are focused on electrification and have adopted initiatives to prohibit the construction of new natural gas distribution facilities. Any such initiatives and legislation could have a material impact on our results of operations, financial condition and cash flows.

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

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

Each of our Electric and Gas Utilities are permitted to recover certain costs (such as increased fuel and purchased power costs or integrity capital investments) outside of a base rate review in order to stabilize customer rates and reduce regulatory lag. If regulators decide to discontinue these tariff-based recovery mechanisms, it could negatively impact results of operations, financial condition and cash flows.

Costs could significantly increase to achieve or maintain compliance with existing or future environmental laws, regulations or requirements.

Our business segments are subject to numerous environmental laws and regulations affecting many aspects of present and future operations, including air emissions (i.e. SO_2, NO_x, volatile organic compounds, particulate matter and GHG), water quality, wastewater discharges, solid waste and hazardous waste. These laws and regulations may result in increased capital, operating and other costs. These laws and regulations generally require the business segments to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Compliance with environmental laws and regulations may require significant expenditures, including expenditures for cleanup costs and damages arising from contaminated properties. Failure or inability to comply with evolving environmental regulations may result in the imposition of fines, penalties and injunctive measures affecting operating assets.

Our business segments may not be successful in recovering increased capital and operating costs incurred to comply with new environmental regulations through existing regulatory rate structures and contracts with customers. More stringent environmental laws or regulations could result in additional costs of operation for existing facilities or impede the development of new facilities. Although it is not expected that the costs to comply with current environmental regulations will have a material adverse effect on our business segments' financial position, results of operations or cash flows, future environmental compliance costs could have a significant negative impact.

Legislative and regulatory requirements may lead to increased costs and result in compliance penalties.

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

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

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

Changes in Federal tax law may significantly impact our business.

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

OPERATING RISKS

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

The risks associated with management of these operations include:

- Inherent dangers. Electricity and natural gas can be dangerous to employees and the general public. Failures of or contact with power lines, natural gas pipelines or service facilities and equipment may result in fires, explosions, property damage and personal injuries, including death. While we maintain liability and property insurance coverage, such policies are subject to certain limits and deductibles. The occurrence of any of these events may not be fully covered by our insurance;

- Weather, natural conditions and disasters. Severe weather events, such as snow and ice storms, fires, tornadoes, strong winds, significant thunderstorms, flooding and drought, could negatively impact operations, including our ability to provide energy safely, reliably and profitably and our ability to complete construction, expansion or refurbishment of facilities as planned;

- Acts of sabotage, terrorism or other malicious attacks. Damage to our facilities due to deliberate acts could lead to outages or other adverse effects;

- Operating hazards. Operating hazards such as leaks, mechanical problems and accidents, including fires or explosions could impact employee and public safety, reliability and customer confidence;

- Equipment and processes. Breakdown or failure of equipment or processes, unavailability or increased cost of equipment, and performance below expected levels of output or efficiency could negatively impact our results of operations;

- Disrupted transmission and distribution. We depend on transmission and distribution facilities, including those operated by unaffiliated parties, to deliver the electricity and gas that we sell to our retail and wholesale customers. If transmission is interrupted physically, mechanically, or with cyber means, our ability to sell or deliver utility services and satisfy our contractual obligations may be hindered;

- Natural gas supply for generation and distribution. Our regulated utilities and non-regulated entities purchase natural gas from a number of suppliers for our generating facilities and for distribution to our customers. Our results of operations could be negatively impacted by the lack of availability and cost of natural gas, and disruptions in the delivery of natural gas due to various factors, including but not limited to, transportation delays, labor relations, weather and environmental regulations;

- Replacement power. The cost of supplying or securing replacement power during scheduled and unscheduled outages of generation facilities could negatively impact our results of operations;

- Governmental permits. The inability to obtain required governmental permits and approvals along with the cost of complying with or satisfying conditions imposed upon such approvals could negatively impact our ability to operate and our results of operations;

- Operational limitations. Operational limitations imposed by environmental and other regulatory requirements and contractual agreements, including those that restrict the timing of generation plant scheduled outages, could negatively impact our results of operations;

- Increased costs. Increased capital and operating costs to comply with increasingly stringent laws and regulations; unexpected engineering, environmental and geological problems; and unanticipated cost overruns could negatively impact our results of operations;

- Labor and labor relations. The cost of recruiting and retaining skilled technical labor or the unavailability of such resources could have a negative impact on our operations. Our ability to transition and replace our retirement-eligible utility employees is a risk; at December 31, 2020, approximately 23% of our Electric Utilities and Gas Utilities employees were eligible for regular or early retirement. Our ability to avoid or minimize supply interruptions, work stoppages and labor disputes is also a risk; approximately 25% of our employees are represented by unions;

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

The ongoing operation of our business involves the risks described above, in addition to risks associated with threats to our overall business model, such as electrification initiatives. Any of these risks could cause us to experience negative financial results and damage to our reputation and public confidence. These risks could cause us to incur significant costs or be unable to deliver energy and/or operate below expected capacity levels, which in turn could reduce revenues or cause us to incur higher operating and maintenance costs and penalties. While we maintain insurance and obtain warranties from vendors and obligate contractors to meet certain performance levels, the proceeds of such insurance and our rights under contracts, warranties or performance guarantees may not be timely or adequate to cover lost revenues, increased expenses, liability or liquidated damage payments.

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

To effectively operate our business, we rely upon a sophisticated electronic control system, information and operation technology systems and network infrastructure to generate, distribute and deliver energy, and collect and retain sensitive information including personal information about our customers and employees. Cyberattacks, terrorism or other malicious acts targeting electronic control systems could result in a full or partial disruption of our electric and/or gas operations. Attacks targeting other key technology systems, including our third-party vendors' information systems, could further add to a full or partial disruption of our operations. Any disruption of these operations could result in a loss of service to customers and associated revenues, as well as significant expense to repair damages and remedy security breaches. In addition, any theft, loss and/or fraudulent use of customer, shareowner, employee or proprietary data could subject us to significant litigation, liability and costs, as well as adversely impact our reputation with customers and regulators, among others.

We have instituted security measures and safeguards to protect our operational systems and information technology assets, including certain safeguards required by FERC. Despite our implementation of security measures and safeguards, all of our technology systems may still be vulnerable to disability, failures or unauthorized access.

Weather conditions, including the impacts of climate change, may cause fluctuation in customer usage.

Our utility businesses are seasonal businesses and weather conditions and patterns can have a material impact on our operating performance. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease. Demand for electricity is typically greater in the summer and winter months associated with cooling and heating, respectively. Demand for natural gas depends heavily upon winter-weather patterns throughout our service territory and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our utility operations have historically generated lower revenues and income when weather conditions are cooler than normal in the summer and warmer than normal in the winter. Demand for natural gas is also impacted by summer weather patterns that are cooler than normal and provide higher than normal precipitation; both of which can reduce natural gas demand for irrigation. Unusually mild summers and winters, therefore, could have an adverse effect on our financial operating results, including earnings, cash flow and liquidity.

FINANCIAL RISKS

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

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

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

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

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

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

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

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

There is no assurance as to the amount, if any, of future dividends to the holding company because these subsidiaries depend on our future earnings, capital requirements and financial condition and are subject to declaration by the Board of Directors. See "Liquidity and Capital Resources" within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 and Note 9 of our Notes to Consolidated Financial Statements of this Annual Report on Form 10-K for further information regarding these restrictions and their impact on our liquidity.

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

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

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

National and regional economic conditions may cause increased counterparty credit risk, late payments and uncollectible accounts.

A future recession or pandemic, if one occurs, may lead to an increase in late payments or non-payment from retail residential, commercial and industrial utility customers, as well as from our non-utility customers. If late payments and uncollectible accounts increase, earnings and cash flows from our continuing operations may be reduced.

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

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

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

Assumptions related to interest rates, expected return on investments, mortality and other key actuarial assumptions have a significant impact on our funding requirements and the expense recognized related to these plans. An adverse change to key assumptions associated with our defined benefit retirement plans may require significant unplanned contributions to the plans which could adversely affect our financial operating results including earnings, cash flow and liquidity.

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

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

PANDEMIC RISK

Our business operations, results of operations, financial condition and cash flows could be adversely affected by the coronavirus (COVID-19) pandemic.

We have responded to the global pandemic of COVID-19 by taking steps to mitigate the potential risks to us posed by its spread.

For the year ended December 31, 2020, the COVID-19 pandemic had a limited net financial impact on our business operations, financial condition and cash flows. In particular, we experienced:

- Increased allowance for credit losses and bad debt expense due to anticipated customer non-payment as a result of suspended disconnections;
- Increased costs due to sequestration of mission-critical and essential employees;
- Lower commercial and certain transport volumes partially offset by higher electric and natural gas residential usage;
- Waived customer late payment fees;
- Reduced availability of our employees;
- Increased costs for personal protection equipment and cleaning supplies;
- Minimal disruptions receiving the materials and supplies necessary to maintain operations and continue executing our capital investment plan;
- Minimal impacts to the availability of our contractors;
- Minimal decline in the funded status of our pension plan;
- Minimal interest expense increase due to disruptions in the Commercial Paper markets; and
- Reduced training, travel, and outside services related expenses.

Should the COVID-19 pandemic continue for a prolonged period or impact the areas we serve more significantly than it has to date, our business operations, financial condition and cash flows could be impacted in more significant ways. In addition to exacerbating the impacts described above, we could experience:

- Adverse impacts on our strategic business plans, growth strategy and capital investments;
- Increased adverse impacts to electricity and natural gas demand from our customers, particularly from commercial and industrial customers;
- Further reduction in the availability of our employees and contractors;
- Increased costs as a result of our preventative measures, such as sequestration of essential employees and facility cleaning services;
- Increased allowance for credit losses and bad debt expense as a result of delayed or non-payment from our customers, both of which could be magnified by Federal or state government legislation that requires us to extend suspensions of disconnections for non-payment;
- Delays and disruptions in the availability, timely delivery and cost of materials and components used in our operations;
- Disruptions in the commercial operation dates of certain projects impacting qualification criteria for certain tax credits and triggering potential damages under our power purchase agreements;
- Deterioration of the credit quality of our counterparties, including gas commodity contract counterparties, power purchase agreement counterparties, contractors or retail customers, that could result in credit losses;
- Impairment of goodwill or long-lived assets;
- Adverse impacts on our ability to construct and operate facilities;
- Inability to meet the requirements of the covenants in our existing credit facilities, including covenants regarding Consolidated Indebtedness to Capitalization Ratio;
- Deterioration in our financial metrics or the business environment that adversely impacts our credit ratings;
- Delay in the permitting process of certain development projects, affecting the timing of final investment decisions and start dates of construction;
- Adverse impact on our liquidity position and cost of and ability to access funds from financial institutions and capital markets; and
- Delays in our ability to change rates through regulatory proceedings.

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.

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.

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.

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.

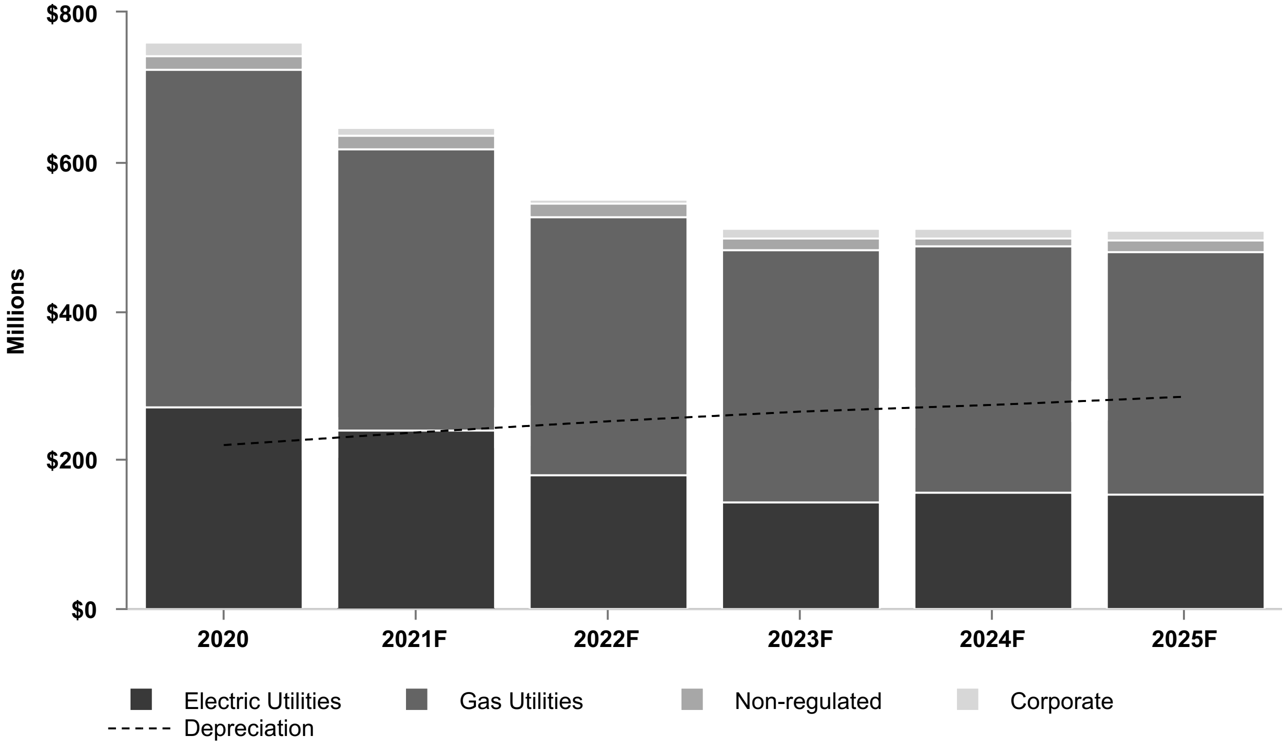
Our strategy focuses on improving the way we serve customers with safe, reliable, affordable and cleaner energy while improving the lives of the customers and communities we serve. Our emphasis is on consistently outperforming utility industry averages in key safety metrics; transforming the customer 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.

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.

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.

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.

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 though 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.

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.

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.

<u>2020 Compared to 2019</u>

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.

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.

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

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	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%

(For the year ended December 31,)

(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.

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.

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.

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.

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.

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.

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.

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.

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.

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.

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. 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.

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.

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.

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.

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.

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

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).

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.

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

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.

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	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.

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS
(Continued)

	As of	
	December 31, 2020	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.

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.

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.

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.

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.

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.

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.

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.

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.

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

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.

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.

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.

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.

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.

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.

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.

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.

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

(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.

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

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.

(5) PROPERTY, PLANT AND EQUIPMENT

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

Electric Utilities	2020 Property, Plant and Equipment	2020 Weighted Average Useful Life (in years)	2019 Property, Plant and Equipment	2019 Weighted Average Useful Life (in years)	Lives (in years) Minimum	Lives (in years) 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.

Gas Utilities	2020 Property, Plant and Equipment	2020 Weighted Average Useful Life (in years)	2019 Property, Plant and Equipment	2019 Weighted Average Useful Life (in years)	Lives (in years) Minimum	Lives (in years) 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.

	2020					Lives (in years)		
	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	Minimum	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					Lives (in years)		
	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	Minimum	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					Lives (in years)		
	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	Minimum	Maximum
Corporate	$ 5,692	$ 16,402	$ 22,094	$ (1,144)	$ 20,950	10	10	22

	2019					Lives (in years)		
	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	Minimum	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.

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.

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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):

		Interest Rate at	Balance Outstanding	
	Due Date	December 31, 2020	December 31, 2020	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.

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.

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.

	2020	2019	2018		2020	2019	2018
Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in OCI			Income Statement Location	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.

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.

	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.

(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	Amount Reclassified from AOCI 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)

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)

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(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.

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%

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

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

10-K

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.

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.

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.

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

Weighted-average assumptions used to determine benefit obligations:	Defined Benefit Pension Plan			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plan		
	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

Weighted-average assumptions used to determine net periodic benefit cost for plan year:	Defined Benefit Pension Plan			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plan		
	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

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.

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%

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.

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.

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.

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.

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.

(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

Year ended December 31, 2020	Electric Utilities	Gas Utilities	Power Generation	Mining	Corporate	Inter-Company Eliminations	Total
	Consolidating Income Statement						
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

	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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	Consolidating Income Statement						
Year ended December 31, 2018	Electric Utilities	Gas Utilities	Power Generation	Mining	Corporate	Inter-Company Eliminations	Total
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.

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.

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.

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).
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).
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).

10.26	Coal Leases between WRDC and the Federal Government -Dated May 1, 1959 (filed as Exhibit 5(i) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(h) to the Registrant's Form 10-K for 1989) -Dated April 1, 1961 (filed as Exhibit 5(j) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(i) to Registrant's Form 10-K for 1989) -Dated October 1, 1965 (filed as Exhibit 5(k) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(j) to the Registrant's Form 10-K for 1989).
10.27	Assignment of Mining Leases and Related Agreement effective May 27, 1997, between WRDC and Kerr-McGee Coal Corporation (filed as Exhibit 10(u) to the Registrant's Form 10-K for 1997).
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.

SIGNATURES

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

BLACK HILLS CORPORATION

By: /S/ LINDEN R. EVANS

Linden R. Evans, President and Chief Executive Officer

Dated: February 26, 2021

10-K

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

/S/ STEVEN R. MILLS Steven R. Mills	Director and Chairman	February 26, 2021
/S/ LINDEN R. EVANS Linden R. Evans, President and Chief Executive Officer	Director and Principal Executive Officer	February 26, 2021
/S/ RICHARD W. KINZLEY Richard W. Kinzley, Senior Vice President and Chief Financial Officer	Principal Financial and Accounting Officer	February 26, 2021
/S/ BARRY M. GRANGER Barry M. Granger	Director	February 26, 2021
/S/ TONY A. JENSEN Tony A. Jensen	Director	February 26, 2021
/S/ MICHAEL H. MADISON Michael H. Madison	Director	February 26, 2021
/S/ KATHLEEN S. MCALLISTER Kathleen S. McAllister	Director	February 26, 2021
/S/ ROBERT P. OTTO Robert P. Otto	Director	February 26, 2021
/S/ SCOTT M. PROCHAZKA Scott M. Prochazka	Director	February 26, 2021
/S/ REBECCA B. ROBERTS Rebecca B. Roberts	Director	February 26, 2021
/S/ MARK A. SCHOBER Mark A. Schober	Director	February 26, 2021
/S/ TERESA A. TAYLOR Teresa A. Taylor	Director	February 26, 2021
/S/ JOHN B. VERING John B. Vering	Director	February 26, 2021

Earnings Per Share, as adjusted (Non-GAAP Measure)	Year Ended Dec. 31 2020	2019	2018	2017	2016	2015
Income from continuing operations available for common stock (GAAP)	**$ 3.65**	**$ 3.28**	**$ 4.78**	**$ 3.52**	**$ 2.57**	**$ 3.12**
Adjustments (loss) (*pre-tax*):						
Impairment of investment	0.11	0.32	-	-	-	-
Integration expenses	-	-	-	0.08	0.86	0.23
Tax reform and other tax items	-	-	0.07	(0.21)	-	-
Legal restructuring - income tax benefit	-	-	(1.31)	-	-	-
Total Adjustments	0.11	0.32	(1.24)	(0.13)	0.86	0.23
Taxes on Adjustments:						
Impairment of investment	(0.03)	(0.07)	-	-	-	-
Acquisition costs	-	-	-	(0.03)	(0.30)	(0.08)
Total tax on adjustments	(0.03)	(0.07)	-	(0.03)	(0.30)	(0.08)
Earnings Per Share from continuing operations available for common stock, as adjusted (Non-GAAP)	**$ 3.73**	**$ 3.53**	**$ 3.54**	**$ 3.36**	**$ 3.13**	**$ 3.27**

* 2.7 percent compound annual growth rate in earnings per share from continuing operations available for common stock, as adjusted, from 2015 to 2020

EBITDA, as adjusted (Non-GAAP Measure, in millions)	Year Ended Dec. 31 2020	2019	2018	2017	2016	2015
Income from continuing operations (GAAP)	**$ 242.8**	**$ 213.3**	**$ 279.5**	**$ 208.4**	**$ 146.8**	**$ 141.5**
Depreciation, depletion and amortization	224.5	209.1	196.3	188.2	175.5	126.5
Interest expense, net	143.5	137.7	140.0	137.1	134.7	83.0
Income tax expense	32.9	29.6	(23.7)	73.4	59.1	78.7
Rounding	(0.1)	-	0.1	(0.1)	-	0.1
EBITDA (Non-GAAP Measure)	**643.6**	**589.7**	**592.2**	**607.0**	**516.1**	**429.8**
Less: Adjustments for unique items						
Impairmet of investment	**6.9**	**19.7**	**-**	**-**	**-**	**-**
Acquisition costs	-	-	-	4.4	43.7	3.6
EBITDA, as adjusted (Non-GAAP Measure)	**$ 650.5**	**$ 609.4**	**$ 592.2**	**$ 611.4**	**$ 559.8**	**$ 433.4**

* 8.5 percent compound annual growth rate in EBITDA, as adjusted, from 2015 to 2020

Earnings per share, as adjusted

Earnings per share, as adjusted, is a Non-GAAP financial measure. Earnings per share, as adjusted, is defined as GAAP Earnings per share, adjusted for expenses, gains and losses that the Company believes do not reflect the Company's core operating performance. Examples of these types of adjustments may include unique one-time non-budgeted events impairment of assets, acquisition and disposition costs, and other adjustments noted in the earnings reconciliation tables in this presentation.

EBITDA and EBITDA, as adjusted

We believe that our presentation of earnings before interest, income taxes, depreciation and amortization (EBITDA) and EBITDA, as adjusted (EBITDA adjusted for special items as defined by management), both non-GAAP measures, are important supplemental measures of operating performance. We believe EBITDA and EBITDA, as adjusted, when considered with measures calculated in accordance with GAAP, give investors a more complete understanding of operating results before the impact of investing and financing transactions and income taxes. We have chosen to provide this information to investors to enable them to perform more meaningful comparisons of past and present operating results and as a means to evaluate the results of core on-going operations.

Limitations on the Use of Non-GAAP Measures

Non-GAAP measures have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP. Our presentation of these non-GAAP financial measures should not be construed as an inference that our future results will not be affected by unusual, non-routine, or non-recurring items.

Non-GAAP measures should be used in addition to and in conjunction with results presented in accordance with GAAP. Non-GAAP measures should not be considered as an alternative to net income, operating income or any other operating performance measure prescribed by GAAP, nor should these measures be relied upon to the exclusion of GAAP financial measures. Our non-GAAP measures reflect an additional way of viewing our operations that we believe, when viewed with our GAAP results and the reconciliation to the corresponding GAAP financial measures, provide a more complete understanding of factors and trends affecting our business than could be obtained absent this disclosure. Management strongly encourages investors to review our financial information in its entirety and not rely on a single financial measure.

BOARD OF DIRECTORS

Linden R. Evans, age 58, was elected to the Board of Directors on November 1, 2018 and named President and CEO on January 1, 2019. Mr. Evans was President and Chief Operating Officer from January 2016 to January 2019 and served as President and Chief Operating Officer of the Company's utilities from 2004 to 2015. In 2003 and 2004, he served as Vice President and General Manager of the Company's former telecommunication subsidiary, and as Associate Counsel from 2001 to 2003.

Barry M. Granger, age 61, was elected to the Board in October 2020. He has more than 35 years of experience with DuPont and Dow Chemical Companies where he successfully grew complex and large businesses, developed and commercialized new technologies and optimized business processes. Currently, Mr. Granger is Managing Partner and Co-Founder of B3 Technology Investments, a start-up private equity firm.

Tony A. Jensen, age 58, was elected to the Board in 2019 and is a member of the Compensation Committee. He was President and CEO of Royal Gold, Inc., a company engaged in the business of acquiring and managing precious metal streams, royalties, and similar interests, from 2006 to 2019, President and COO from 2003 to 2006, and a Board Member from 2004 to 2019. Mr. Jensen has more than 35 years of experience in the mining industries where he held various roles in engineering, finance, strategic growth and operations.

Michael H. Madison, age 72, was elected to the Board in 2012 and is a member of the Compensation and Governance Committees. He was President and CEO and Director of Cleco Corporation, a public utility holding company, from 2005 to 2011, President and COO of Cleco Power, LLC from 2003 to 2005, and State President, Louisiana-Arkansas with American Electric Power from 2000 to 2003.

Kathleen S. McAllister, age 56, was elected to the Board in 2019 and is a member of the Audit Committee. She was President, CEO and Director of Transocean Partners LLC, a growth-oriented public company and subsidiary of Transocean Ltd., an international provider of offshore contract drilling services for oil and gas wells, from 2014 to 2016, and CFO in 2016. She also served in other leadership roles at Transocean Ltd. beginning in 2005, including Vice President and Treasurer. She also serves on the Boards of Hoegh LNG Partners LP and Maersk Drilling.

Steven R. Mills, age 65, was elected to the Board in 2011. He was elected Chairman in April 2020 and previously served as Lead Director from April 2019 to April 2020. He is a member of the Audit and Governance Committees. Steve is a Consultant and Advisor to Arianna S.A., a European-based specialized investment fund. He serves on the Board of Directors of Amyris, Inc., a renewable products company, since 2018, and previously served as CFO, from May 2012 to December 2013. Prior to that he had a 33-year career at Archer Daniels Midland Company, one of the world's largest agricultural processors and food ingredient providers, culminating with Senior Executive Vice President Performance and Growth, from 2010 to 2012.

BOARD OF DIRECTORS

Robert P. Otto, age 61, was elected to the Board in 2017 and is a member of the Audit Committee. He has been the owner of Bob Otto Consulting LLC, providing strategic planning and services in cyber security, intelligence and reconnaissance since 2017. He retired from the U.S. Air Force in 2016 as a lieutenant general. He served as a general officer since 2008, culminating as the Deputy Chief of Staff for Intelligence, Surveillance and Reconnaissance.

Scott M. Prochazka, age 55, was elected to the Board in October 2020. He was President and CEO and a Board Member of CenterPoint Energy, a publicly traded utility company with over $30 billion of electric and natural gas utility assets, from 2014–2020, and Chief Operating Officer from 2012–2014. Mr. Prochazka has more than 20 years of experience in the utility industry where he held various roles in customer care and support services, strategic growth and utility operations.

Rebecca B. Roberts, age 68, was elected to the Board in 2011, chairs the Governance Committee and is a member of the Compensation Committee. She was President of Chevron Pipe Line Co., a transporter of crude oil, refined petroleum products, liquefied petroleum gas, natural gas and chemicals within the U.S. from 2006 to 2011, and President of Chevron Global Power Generation from 2003 to 2006. She also serves on the Boards of AbbVie, Inc. and MSA Safety Inc.

Mark A. Schober, age 65, was elected to the Board in 2015 and chairs the Audit Committee. He was Senior Vice President and CFO of ALLETE, Inc., a public energy company, from 2006 to 2014. He previously held several positions in accounting and finance.

Teresa A. Taylor, age 57, was elected to the Board in 2016 and chairs the Compensation Committee. She has been CEO of Blue Valley Advisors, LLC, since 2011. She previously served as COO of Qwest Communications, Inc., a telecommunications carrier, from 2009 to 2011. She also served in other leadership roles at Qwest and the former U.S. West beginning in 1987, including Executive Vice President and Chief Administrative Officer. She also serves on the Board of T-Mobile USA, Inc.

John B. Vering, age 71, was elected to the Board in 2005. He is a member of the Audit and Governance Committees and served as Lead Director from 2016 to April 2019. He retired as Managing Director of Lone Mountain Investments, Inc., an oil and gas investment firm, in 2019. He previously held several executive positions in the oil and gas industry.

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 — Strategic Initiatives since July 2020. He served as Senior Vice President — Chief Information Officer since the closing of the Aquila Transaction in 2008. 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.

Erik D. 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.

EXECUTIVE OFFICERS

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 our 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, Vice President and General Manager from 2003 to 2004. Mr. Wevik has 35 years of experience with the Company.

INVESTOR INFORMATION

Common Stock
Transfer Agent, Registrar &
Dividend Disbursing Agent
EQ Shareowner Services
P.O. Box 64854
St. Paul, MN 55164-0854
800-468-9716
www.shareowneronline.com

Senior Unsecured Notes — Black Hills Corporation
Wells Fargo Bank, N.A.
Corporate Trust Services
MAC 9300-070
600 South 4th Street
Minneapolis, MN 55415

First Mortgage Bonds — Black Hills Power, Inc.
The Bank of New York Mellon
Corporate Trust, CF
101 Barclay 7 West
New York, NY 10286

First Mortgage Bonds — Cheyenne Light, Fuel & Power
Wells Fargo Bank, N.A.
Corporate Trust Services
MAC 9300-070
600 South 4th Street
Minneapolis, MN 55415

Environmental Improvement Revenue Bonds — Black Hills Power, Inc.
Trustee & Paying Agent
The Bank of New York Mellon
100 Pine Street, Suite 3150
San Francisco, CA 94111

Industrial Development Revenue Bonds — Cheyenne Light, Fuel & Power
Trustee & Paying Agent
Corporate Trust Services
US Bank National Association
EP-MN-WN3L
60 Livingston Avenue
St. Paul, MN 55107

Corporate Offices
Black Hills Corporation
P.O. Box 1400
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Rapid City, SD 57709
605-721-1700
www.blackhillscorp.com

2021 Annual Meeting
The Annual Meeting of Shareholders will be held at Horizon Point, the Company's corporate headquarters at 7001 Mount Rushmore Road, Rapid City, South Dakota, at 9:30 a.m. local time on Tuesday, April 27, 2021. Prior to the meeting, formal notice, proxy statement and proxy will be mailed to shareholders.

Market for Equity Securities
The Company's Common Stock ($1 par value) is traded on the New York Stock Exchange. Quotations for the Common Stock are reported under the symbol BKH. The continued interest and support of equity owners are appreciated. The Company has declared Common Stock dividends payable in each year since its incorporation in 1941. Regular quarterly dividends when declared are normally payable on March 1, June 1, September 1 and December 1.

Internet Account Access
Registered shareholders can access their accounts electronically at www.shareowneronline.com. Shareowner Online allows shareholders to view their account balance, dividend information, reinvestment details and much more. The transfer agent maintains stockholder account access.

Direct Deposit of Dividends
We encourage you to consider the direct deposit of your dividends. With direct deposit, your quarterly dividend payment can be automatically transferred on the dividend payment date to the bank, savings and loan, or credit union of your choice. Direct deposit assures payments are credited to shareholders' accounts without delay. A form is attached to your dividend check where you can request information about this method of payment. Questions regarding direct deposit should be directed to EQ Shareowner Services.

Dividend Reinvestment and Direct Stock Purchase Plan
A Dividend Reinvestment and Direct Stock Purchase Plan provides interested investors the opportunity to purchase shares of the Company's Common Stock and to reinvest all or a percentage of their dividends. For complete details, including enrollment, contact the transfer agent, EQ Shareowner Services.

Plan information is also available at www.shareowneronline.com.

Website Access to Reports
The reports we file with the SEC are available free of charge at our website www.blackhillscorp.com as soon as reasonably practicable after they are filed. In addition, the charters of our Audit, Governance and Compensation Committees are located on our website along with our Code of Business Conduct, Code of Ethics for our Chief Executive Officer and Senior Finance Officer, Corporate Governance Guidelines of our Board of Directors, and Policy for Director Independence.

Black Hills Corporation™
Ready

During the design and 2020 construction of our Corriedale Wind Energy Project located just west of Cheyenne, Wyoming, environmental professionals like Ally carefully evaluated and monitored the site to mitigate risks to protected, threatened or endangered species, including eagles and migratory birds. We are a leader among energy companies in our Avian Protection Plans due to our comprehensive planning and mitigation strategies to encompass all areas of our operations.