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APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
CITY OF EL PASO'S SEVENTEENTH REQUEST FOR INFORMATION
QUESTION NOS. CEP 17-1 THROUGH CEP 17-23

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DECEMBER 8, 2021

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QUESTION NOS. CEP 17-1 THROUGH CEP 17-23

CEP 17-1:

Reference the Rebuttal testimony of Jennifer E. Nelson at 12, footnote 20, Please provide a copy of the S & P Global Ratings, *North American Regulated Utilities' Negative Outlook Could See Modest Improvement* (January 20 , 2021).

RESPONSE:

Please see CEP 17-1, Attachment 1.

Preparer: Jennifer E. Nelson   Title: Assistant Vice President – Concentric Energy Advisors

Sponsor: Jennifer E. Nelson   Title: Assistant Vice President – Concentric Energy Advisors

COMMENTS — 20 Jan, 2021 | 18:22 —

APAC, United States of America, Latin America, Canada, EMEA, APAC

North American Regulated Utilities' Negative Outlook Could See Modest Improvement

Primary Credit Analyst: **Gabe Grosberg**

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Sector **Oil & Gas, Oil & Gas, Corporates, Infrastructure & Utilities, Utilities & Power**

Tags **Americas, Latin America, APAC, EMEA**

View Analyst Contact Information

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Key Takeaways

- Credit quality for the North American regulated utility industry weakened in 2020. At the beginning of the year about 18% of the industry had a negative outlook or ratings on CreditWatch with negative implications. By the end of the year that percentage had doubled, to about 36%.
- For the first time in a decade downgrades outpaced upgrades for the predominately investment-grade industry.
- The industry generally performed well throughout the pandemic and we expect it will continue to mostly manage through the remaining COVID-19-related risks.
- The main causes of weakening credit quality reflected environment, social, and governance (ESG) risks, regulatory issues, and companies' practice of strategically managing financial measures close to their downgrade threshold with little or no cushion.
- Despite our negative 2021 industry outlook, we expect a modest improvement to credit quality over the next 12 months. We believe Congress is more likely to raise the corporate tax rate, which would improve the industry's financial measures, offset in part by a continued focus on ESG risks.

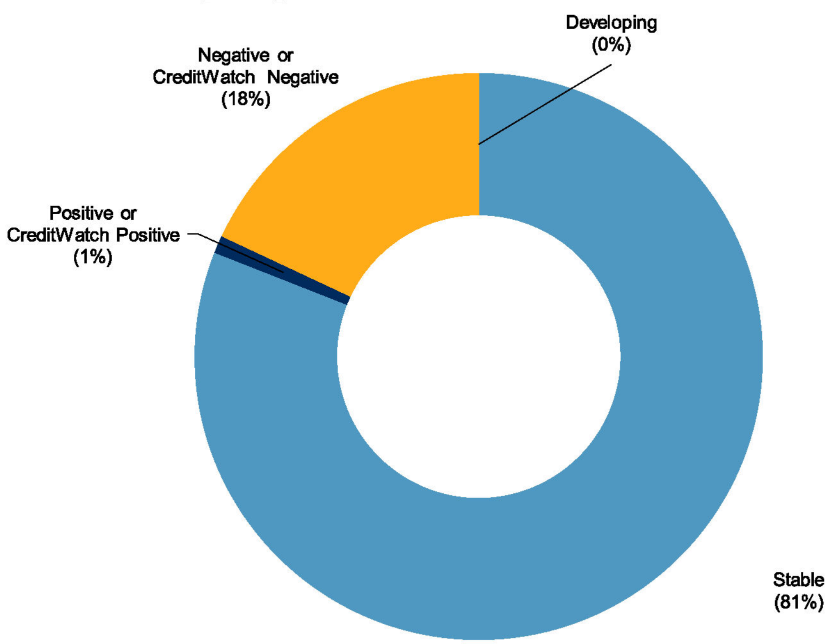
Credit Quality Weakened In 2020

We revised the industry's outlook to negative in the first quarter (
COVID-19: The Outlook For North American Regulated Utilities Turns Negative
, April 2, 2020), citing the already high percentage of companies with a negative outlook or ratings on CreditWatch with negative implications

(18%) and the additional potential credit risks from COVID-19. During the year, the utility industry performed poorly from a credit quality perspective. The negative outlooks or CreditWatch negative listings doubled and downgrades outpaced upgrades for the first time in a decade by about 7 to 1. As a result, while the median rating for the industry remains at 'A-', it is slowly creeping closer to 'BBB+'.

Chart 1

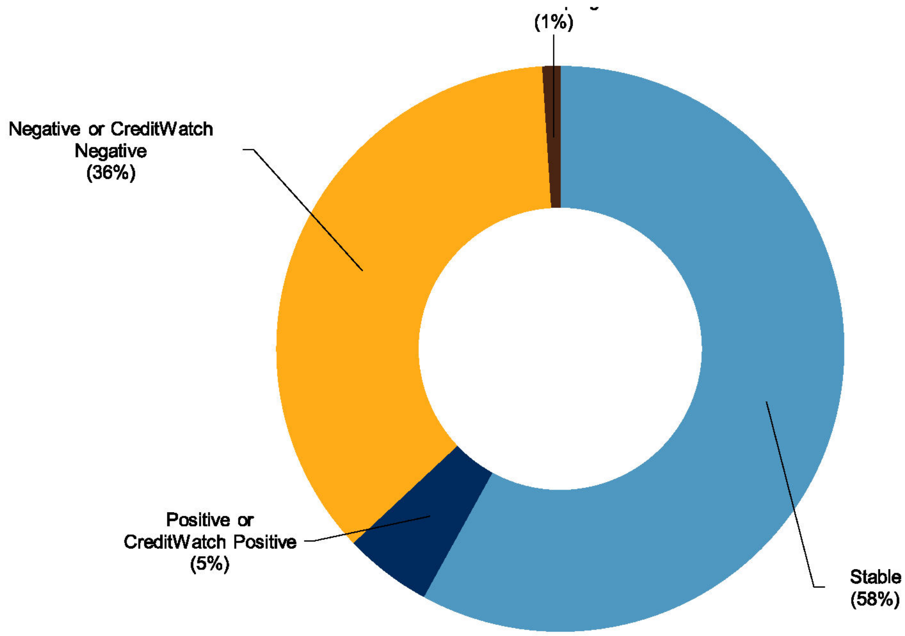
Ratings Outlooks At The Beginning Of 2020



Source: S&P Global Ratings.

Chart 2

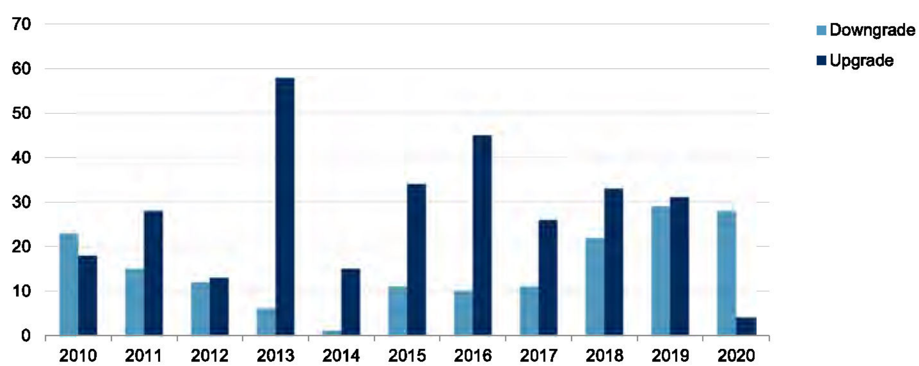
Ratings Outlooks At The End Of 2020



Source: S&P Global Ratings.

Chart 3

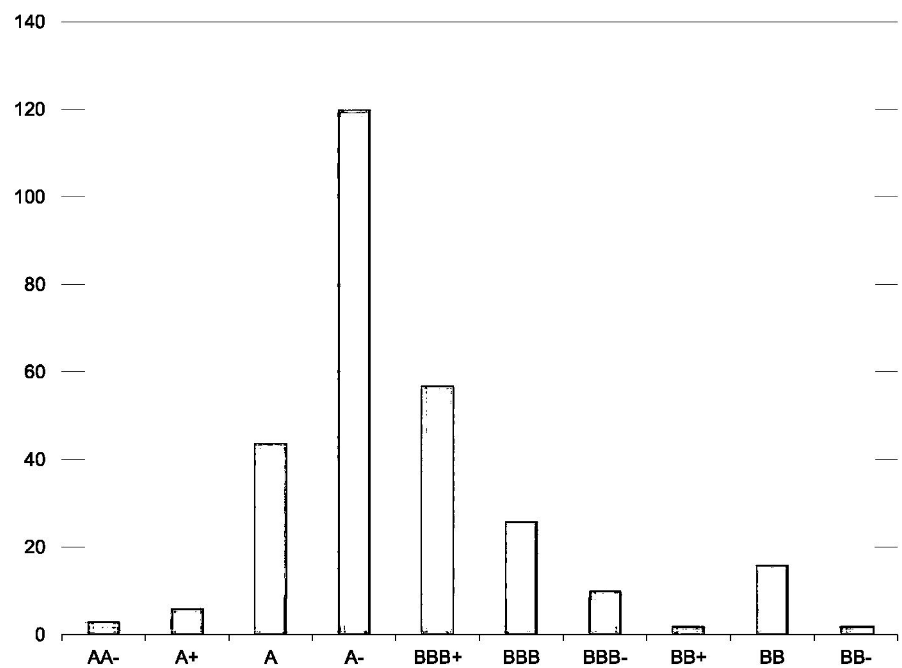
North America Regulated Utilities Upgrades And Downgrades



Source: S&P Global Ratings.

Chart 4

North America Regulated Utilities Rating Distribution



As of Jan. 8, 2021. Source: S&P Global Ratings.

COVID-19 Was Not The Culprit For Weaker Credit Quality

In March 2020, we identified five COVID-19-related risks that could lead to a weakening of the industry's credit quality. We expected that these developments could bring about a deterioration in the industry's 2020 funds from operations (FFO) to debt of about 100 basis points. These risks included the following:

- Lower deliveries to commercial and industrial (C&I) customers;
- Higher bad debt expense;
- Delayed rate case filings, delayed rate case orders, or lower-than-expected rate case outcomes;
- Lack of consistent access to the capital markets; and
- Weaker market returns that could increase postretirement benefit obligations.

Encouragingly, the industry has generally performed well throughout the pandemic. Lower electric and gas deliveries to C&I customers were mostly offset by higher residential deliveries, the industry generally worked well with regulators to defer COVID-19-related costs for future recovery, market returns improved, and the industry generally had consistent access to the capital markets. The one area that we saw some weakness was with regard to rate cases. Many rate case filings were delayed, rate case orders often took longer than expected, and many of the orders were below expectations. This trend generally reflected the weak economy caused by COVID-19 and the difficulties of passing on higher costs to customers during the pandemic. We expect that as vaccines take hold and the pandemic dissipates, the economy will gradually recover, as will the industry's rate case performance.

As vaccine rollouts in several countries continue, S&P Global Ratings believes there remains a high degree of uncertainty about the evolution of the coronavirus pandemic and its economic effects. Widespread immunization, which certain countries might achieve by midyear, will help pave the way for a return to more normal levels of social and economic activity. We use this assumption about vaccine timing in assessing the economic and credit implications associated with the pandemic (see our research here: **www.spglobal.com/ratings**). As the situation evolves, we will update our assumptions and estimates accordingly.

Here's What Happened

The stark weakening of credit quality in 2020 primarily reflected environmental, social, and governance (ESG) factors, regulatory issues, and the industry's practice of continuing to manage its financial measures with little or no financial cushion from the downgrade threshold.

During 2020, we saw a number of ESG-related events that included:

- A bribery charge filed against Exelon Corp.'s subsidiary (
  Exelon Corp. Outlook Revised To Negative On Bribery Charge; Subsidiary Commonwealth Edison Co. Downgraded
  , July 21, 2020).
- Unprecedented wildfire activity throughout California at the beginning of the wildfire season that could have indicated a worsening environment more susceptible to frequent wildfires. (
  Edison International And Subsidiary Outlooks Revised To Negative On Adverse Wildfire Conditions; 'BBB' Ratings Affirmed
  , Sept. 16, 2020;
  PG&E Corp. And Subsidiary Outlooks Revised To Negative On Adverse Wildfire Conditions; 'BB-' Ratings Affirmed
  ; Sept. 16, 2020;
  San Diego Gas & Electric Co. Outlook Revised To Negative On Adverse Wildfire Conditions; 'BBB+' Rating Affirmed
  , Sept. 16, 2020).
- Climate change risks.
  Entergy New Orleans LLC Downgraded To 'BBB' From 'BBB+' On Storm Risks, Outlook Negative
  , Oct. 8, 2020.
- FirstEnergy Corp. terminated three executives including its CEO after it determined that they violated company policies and its code of conduct. This followed the U.S. government filing a criminal complaint against the Speaker of the Ohio House of Representatives and four associates for participating in an approximately $60 million racketeering scheme (
  FirstEnergy Corp. Downgraded to 'BB+' On Termination Of CEO; Ratings Remain On CreditWatch Negative
  , Oct. 30, 2020).
- Duke Energy Corp.'s potentially higher risks regarding its ability to fully and consistently recover coal ash costs (
  Duke Energy Corp. And Subsidiaries Outlooks Revised To Negative On Higher Regulatory Risks, Elevated Spending Plan
  , Dec. 15, 2020).

Regulatory issues also contributed to a weakening of credit quality and included the following 2020 actions:

- **Puget Energy Inc. And Subsidary Ratings Placed On CreditWatch Negative Over Regulatory Concerns**, July 23, 2020.
- **Consolidated Edison Inc. And Subs Outlooks Revised To Negative Amid Potential Political Headwinds; Ratings Affirmed**, Nov. 24, 2020.
- Following our assessment of a modest weakening of the regulatory environment in Alberta we revised our rating outlook on FortisAlberta Inc. to negative. (**FortisAlberta Inc. Ratings Affirmed; Outlook Negative**, Nov. 24, 2020).

During 2020, we revised the outlook on a number of companies to negative and downgraded other companies, reflecting weak financial measures.

- South Jersey Industries Inc. And Subsidiaries Outlook Revised To Negative On Weaker Financial Results; Ratings Affirmed
  , March 10, 2020.
- Emera Inc. And TECO Downgraded On Weak Financials, Outlook Stable; Subsidiaries Ratings Affirmed
  , March 24, 2020.
- ENMAX Corp. Downgraded To 'BBB-'; Off CreditWatch; Outlook Stable, March 24, 2020.
- PNM Resources Inc., Public Service Co. Of New Mexico, Texas-New Mexico Power Co. Downgraded One Notch; Outlook Stable
  , April 6, 2020.
- ALLETE Inc. Downgraded To 'BBB' On Expected Weaker Financial Measures; Outlook Stable
  , April 22, 2020.
- CenterPoint Energy Resources Corp. Ratings Affirmed On Completed Sale Of CenterPoint Energy Services, Outlook Negative
  , June 5, 2020.
- Otter Tail Corp. Outlook Revised To Negative; Ratings Affirmed, Aug. 18, 2020.
- National Grid North America Inc. And Subsidiaries Outlooks Revised To Negative Following Outlook Revision On Parent
  , Aug. 25, 2020.
- ATCO Ltd. And Canadian Utilities Ltd. Outlooks Revised To Negative; Operating Subsidiary CU Inc. Outlook Remains Stable
  , Sept. 17, 2020.

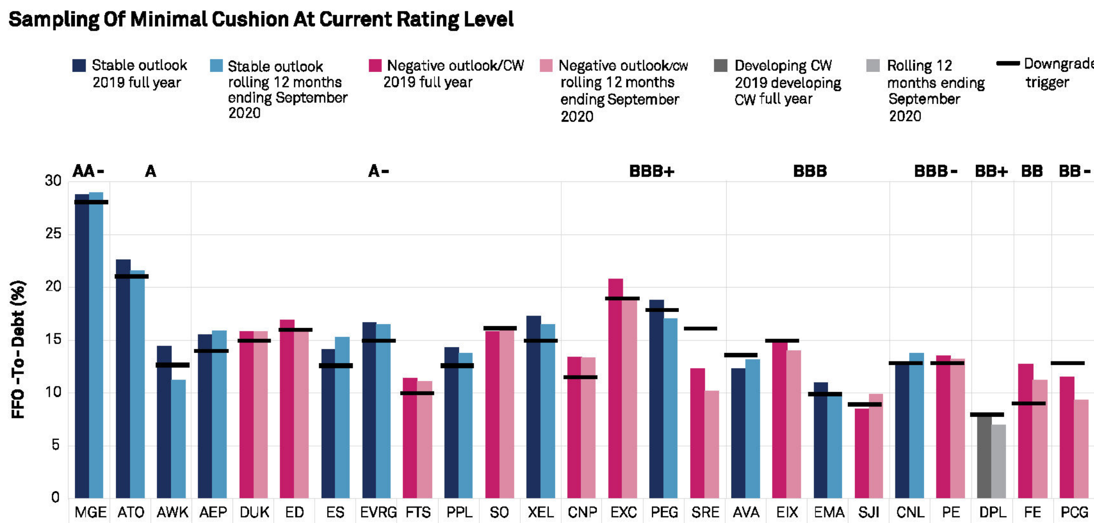
Fortis TCI Ltd. Downgraded To 'BBB-' On Weaker Financial Measures; Outlook Stable

, Oct. 21, 2020

- Middlesex Water Co. Outlook Revised To Negative On Weaker Financial Measures; 'A+' Rating Affirmed
  , Nov. 3, 2020.
- Unitil Corp. And Subsidiaries Outlooks Revised To Negative On Weaker Consolidated Financial Measures; Ratings Affirmed
  , Nov. 5, 2020.

The industry's credit quality continues to be squeezed by the industry's tendency to strategically manage financial measures with only minimal financial cushion.

Chart 5



Note: PE is Puget Energy Inc. Source: S&P Global Ratings and company data.

What will occur in 2021?

We expect a marginal improvement in credit quality in 2021. We think it's likely that Congress will enact a higher corporate tax rate. This will help strengthen the industry's financial measures, partially offset by continued focus on ESG related risks.

Because President-elect Biden won the U.S. presidency and the democrats have control of the U.S House of Representatives and Senate, we expect Congress will more likely implement a higher corporate tax rate. While details of such a plan are limited, a key element of the proposal would likely call for an increase in the corporate tax rate to 28% from 21%. We estimate that this higher tax rate would improve the industry's funds from operations to debt by about 100 basis points (

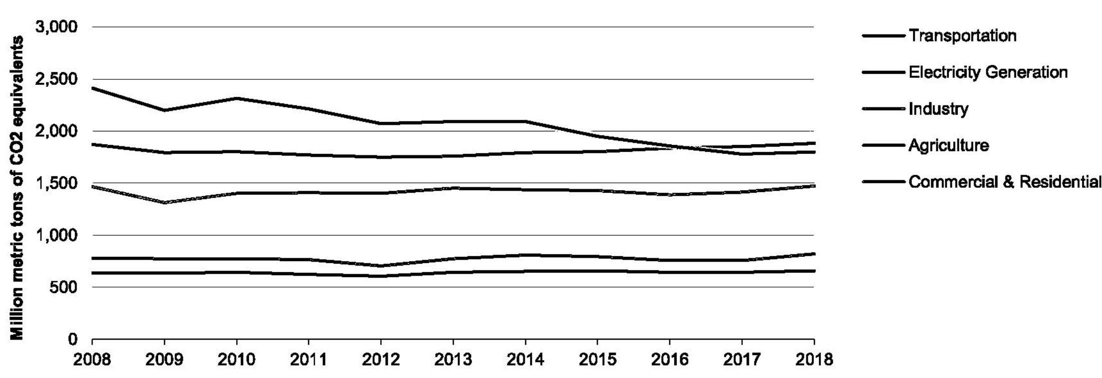
U.S. Regulated Utilities' Credit Metrics Could Strengthen Under Proposed Biden Tax Plan

, Oct. 29, 2020). The improving financial measures would likely boost credit quality, enhancing utilities' financial cushions from their downgrade thresholds.

The industry's environmental risks including its exposure to greenhouse gas (GHG) emissions remain a key concern for investors. Despite the industry's enormous progress over the past decade, it has a way to go. Over the past decade, the industry significantly reduced its reliance on coal-fired generation and its associated level of carbon based emissions. The industry is no longer the number one North American emitter of carbon-based pollutants, reducing its carbon emissions by about 25% and has reduced its reliance on coal-fired generation by about 50%.

Chart 6

GHG Emissions By U.S. Economic Sector

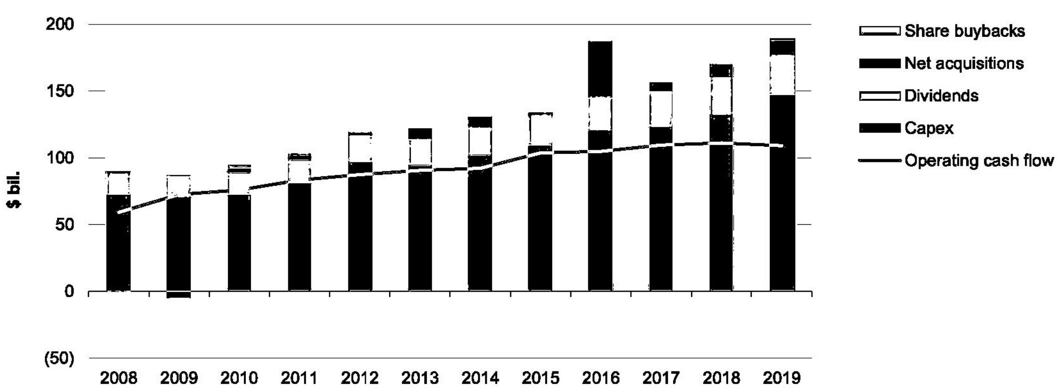


Source: U.S. Environmental Protection Agency.

Still, about 30% of the electric utility industry relies on coal-fired generation for at least 50% of its owned electricity production and about two-thirds of those utilities depend on coal-fired generation for more than 70% of their total generation. Investors are increasingly focused on environmental issues and given that the industry typically operates with negative discretionary cash flow, it relies on consistent access to reasonably priced capital markets. We expect that the continued focus on these ESG risks will weaken credit quality, offsetting much of the credit benefits from a potentially higher corporate tax rate.

Chart 7

Cash Flow And Primary Uses



Source: S&P Global Ratings and company data.

This report does not constitute a rating action.

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CEP 17-2:

Reference the Rebuttal testimony of Jennifer E. Nelson at 12, fn. 23 at 14 footnote. 25 at 15 footnote 28 Please provide a copy of S&P Capital IQ referenced.

RESPONSE:

Please see Ms. Nelson's Excel file of workpapers to her Rebuttal Testimony titled "Nelson Rebuttal WPs ONLY.xlsx" filed November 22, 2021, on the PUCT Interchange site. Specifically, see worksheets labeled "WP13 Ch 3,4_MPG Proxy 30Yr" and "WP 14 Ch 5_Rel Volatility".

Preparer: Jennifer E. Nelson Title: Assistant Vice President – Concentric Energy Advisors

Sponsor: Jennifer E. Nelson Title: Assistant Vice President – Concentric Energy Advisors

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CEP 17-3:

Reference the Rebuttal testimony of Jennifer E. Nelson at 16 footnote 32 Please provide a copy of the Bloomberg News article referenced.

RESPONSE:

Please see CEP 17-3, Attachment 1.

Preparer: Jennifer E. Nelson Title: Assistant Vice President – Concentric Energy Advisers

Sponsor: Jennifer E. Nelson Title: Assistant Vice President – Concentric Energy Advisers

BLOOMBERG NEWS

Nov 10, 2021 15:20:26

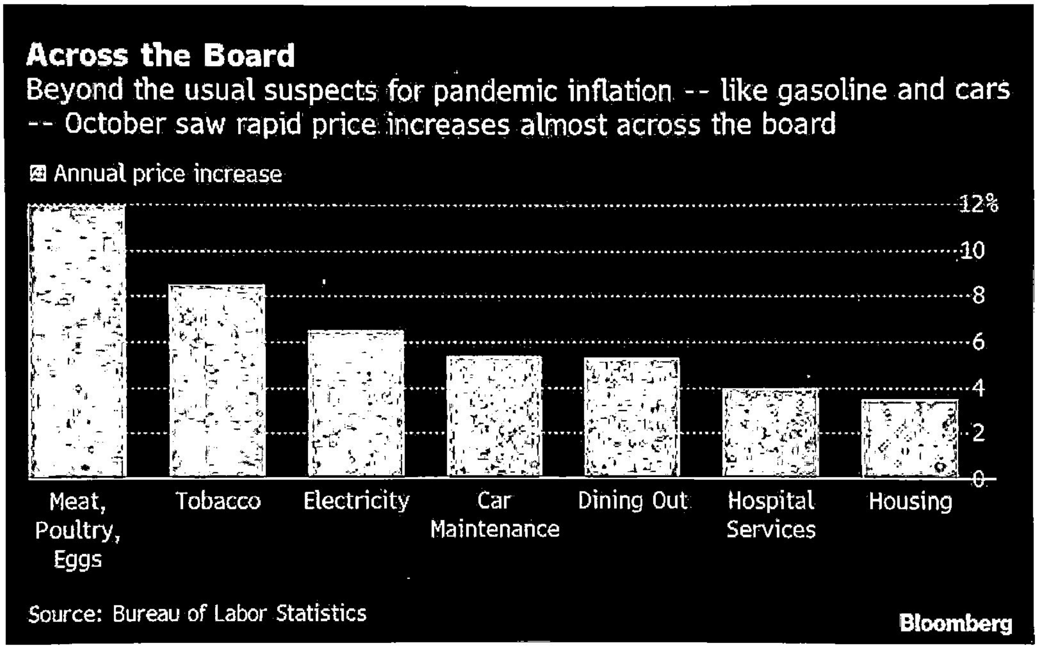
Worst Is Yet to Come for U.S. Inflation as Fed, Biden Feel Heat

- Already at a 30-year high, inflation could approach 7% soon
- Fed faces growing rate pressure; Biden spending plans at risk

By Reade Pickert, Steve Matthews and Katia Dmitrieva

(Bloomberg) -- After U.S. prices climbed by the most in three decades, there's even worse news ahead for households and policy makers: Inflation likely has further to rise before it peaks.

October's annual rate was 6.2%, the highest since 1990, as price increases spread well beyond the parts of the economy most disrupted by pandemic closures. Key drivers, like hot housing markets and a global energy crunch, show few signs of fading away soon -- leading economists to predict even bigger jumps in the coming months.



"We're going to see the inflation picture get worse before it gets better," said Sarah House, senior economist at Wells Fargo & Co. She doesn't expect much relief before next spring.

For the Federal Reserve, and President Joe Biden, that likely seems a long way off -- and pressure for a change of policy course will ratchet up in the meantime, as calls to rein in pandemic support grow louder.

'Tipping Point'

Surging prices are eating into family budgets, wiping out the wage increases that U.S. workers have battled for after last year's jobs wipeout, and squeezing profit margins for small businesses.

The Fed has already begun to back away from the case it's been making since Covid-19 first arrived: that pandemic inflation will be "transitory." It's starting to wind down bond purchases this month, and leaning toward raising interest rates next year instead of waiting until 2023. Wednesday's inflation data could accelerate the timetable.

The U.S..central bank may have arrived at a "tipping point," said James Knightley, chief international economist at ING. "Is it really justifiable to be continuing to stimulate when you've got the economy growing at 6% and inflation increasing at 6% and no sign that there's any loss of momentum in either of those indicators?"

BLOOMBERG NEWS

Knightley expects the Fed's so-called taper to be concluded in the first quarter of 2022 -- about three months ahead of the consensus schedule. And he foresees two 25 basis-point rate hikes to follow by the end of the year, with a growing likelihood that could turn into three.

That's roughly what financial markets expect too. Investors have been betting on a speeded-up hiking cycle for nearly two months. After Wednesday's inflation numbers, yields on five-year Treasuries rose more than 10 basis points.

Read More: Breakevens Surge as Traders Bet on Faster Fed Move After CPI

Not the 1970s

An acceleration of the timetable could show up at next month's meeting of the rate-setting Federal Open Market Committee, said Michael Feroli, chief U.S. economist at JPMorgan Chase & Co. Last time the Fed released a so-called "dot-plot" in September, it showed an even split on whether rates will rise next year.

"It is reasonable to suspect you could get the median to move higher," Feroli said.

What Bloomberg Economics Says...

"We expect headline inflation may top 6.8% year on year in November. The main factors would be persistent price gains for energy and shelter and adverse base effects."

"While the bar for accelerating the pace of Fed taper is extremely high and the central bank is unlikely to do so, today's release -- and the readings in the rest of the year --likely would put them in a very hot seat."

Anna Wong, Bloomberg Economics

Click here to read the full note

Fed officials acknowledge that inflation is sticking around longer than they'd expected. They fret that households and businesses may come to expect more of the same, the kind of change in expectations that can prove self-fulfilling. But they still reckon many price increases are essentially a one-off.

There's no reason why the energy spike of 2021, or the big shift in housing markets driven by work-from-home, should repeat themselves in future years, the argument goes. And labor isn't strong enough to keep bidding wages up like it did in the 1970s.

BLOOMBERG NEWS

That's why there'll be plenty of resistance inside the Fed to any abrupt shift toward tighter policy.

"Inflation is high, it's eye-popping," Mary Daly, president of the San Francisco Fed and one of the central bank's most dovish officials, told Bloomberg TV on Wednesday. Still, "right now it would be premature to start changing our calculations about raising rates," she said. "Uncertainty requires us to wait and watch with vigilance."

'Tight Spot'

Biden, whose party suffered a reversal in state elections last week and must defend thin Congressional majorities in mid-term voting next year, is in the firing line too. Inflation is high on the list of public grievances, and the president called it a "top priority" after Wednesday's data.

One problem for Biden, as he tries to get a $1.75 trillion social-spending plan through Congress, is that he needs votes from centrists like Senator Joe Manchin of West Virginia -- who's voiced concerns that more public spending could make inflation worse. On Wednesday, Manchin called for action against soaring prices, without saying what kind.

Still, it's the Fed -- which is supposed to be responsible for managing inflation -- that's more directly in the firing line.

In the last couple of years the central bank has come up with a new policy framework, essentially allowing it to keep rates lower even when inflation stays a bit above the 2% target, and rolled out emergency programs to dig the economy out of a deep pandemic hole.

Through all of this, it's stressed the importance of accommodative monetary policy to boost employment and growth, and allow wages -- especially for low-income Americans -- to keep rising. But those arguments, drawn up in a world where inflation rarely got near 3%, are getting harder to sustain at 6% plus.

"The fact that inflation is off the business page and on the front page is a problem for an institution trying to preserve its reputation," said Feroli. "They are in a tough spot."

--With assistance from Alex Tanzi and Craig Torres.

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Ben Holland

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CEP 17-4:

Reference the Rebuttal testimony of Jennifer E. Nelson at 18 footnote 37, please provide a copy of the article referenced.

RESPONSE:

Please see CEP 17-4, Attachment 1.

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Sponsor: Jennifer E. Nelson — Title: Assistant Vice President – Concentric Energy Advisers

https://www.wsj.com/articles/global-stock-markets-dow-update-09-28-2021-11632814517

U.S. MARKETS

Stocks Close Sharply Lower as Bond Yields Hit Three-Month High

Tech shares pull S&P 500, Nasdaq down more than 2%, while bond yields rally on inflation concerns

By Akane Otani and Will Horner
Updated Sept. 28, 2021 4:35 pm ET

U.S. stocks tumbled Tuesday, logging their sharpest pullback since May, as rising bond yields deepened a rout in shares of technology companies.

For much of the past decade, many investors had piled into shares of fast-growing technology companies, wagering they would deliver relatively robust profit growth even in a sluggish economic environment. This week, that trade hit a roadblock.

With the economy out of the worst of the pandemic-fueled crisis, the Federal Reserve signaled last week that it could start to reverse its pandemic stimulus programs as soon as November and raise interest rates sometime next year. That appears to have prompted an unwind of some of the market's most enduring trades—pushing Treasury yields to their highest level in months and sending investors out of popular technology stocks.

Investors agree the economic outlook has improved significantly since 2020. But many wonder how well the market will be able to stand on its own once the Fed begins to taper its monthly asset purchases—especially since they credit much of the market's rebound from its pandemic low to extraordinary levels of monetary and fiscal support from Washington. Some investors have also expressed concerns about the economic outlook. Inflation has made a surprising comeback this year, something some worry will start to cut into companies' profit margins. The fast-spreading Delta variant of Covid-19 has also complicated economists' efforts to forecast the global economy's growth outlook.

"People are realizing, or at least remembering, that central banks are going to have to start raising rates," said Altaf Kassam, head of investment strategy for State Street Global

Advisors in Europe. "The patient has become used to being given all these drugs, but soon those drugs are going to have to be reduced."

The S&P 500 fell 90.48 points, or 2%, to 4352.63, marking its second straight day of losses and worst one-day percentage decline since May. The tech-heavy Nasdaq Composite Index slid 423.29 points, or 2.8%, to 14546.68, while the Dow Jones Industrial Average shed 569.38 points, or 1.6%, to 34299.99.

All three major indexes are on course to end the month lower.

Tuesday's market selloff was broad, pulling all but one of the S&P 500's sectors down for the day.

Traders yanked money out of the technology sector. Shares of companies like Facebook, Google parent Alphabet and Microsoft, each of which had vastly outperformed the broader market this year, fell more than 3.5% apiece.

Meanwhile, selling pressure accelerated in the government bond market. The yield on the benchmark 10-year Treasury note rose for a sixth consecutive day Tuesday, climbing from 1.482% Monday to 1.534%, its highest level since late June. Bond yields rise as prices fall.

Shares of energy companies avoided the broader selloff.

Schlumberger added 72 cents, or 2.4%, to $30.91, while ConocoPhillips rose $1.09, or 1.6%, to $67.80. Both stocks benefited from crude oil prices hitting multiyear highs this week, although oil wound up giving up the day's gains to end slightly lower Tuesday. Strategists have attributed the spike to a combination of rising demand and supply shortages.

The jump in commodity prices has ramped up some investors' worries about short-term inflation pressures. Inflation tends to weigh on bond prices, since it erodes the purchasing value of their fixed payments.

Some investors say stocks' recent setbacks aren't surprising after a long period of relative calm. The S&P 500 has risen seven straight months in a row, its longest such streak since the 10 months through January 2018, according to Dow Jones Market Data.

Data suggests investors were heavily positioned in bets on lower interest rates and subdued inflation earlier this month, another factor that might have exacerbated the speed and scale of Tuesday's pullback. In a survey of global fund managers conducted

Sept. 3-9, Bank of America found investors were generally betting on stock prices rising and inflation pressures easing.

“That’s often how it happens—you have quiet and complacent markets and then a gut check,” said Keith Lerner, co-chief investment officer of Truist Advisory Services. Mr. Lerner added that he is still optimistic about the market’s outlook over the longer term.

Elsewhere, European markets slumped, while Asian indexes were mixed.

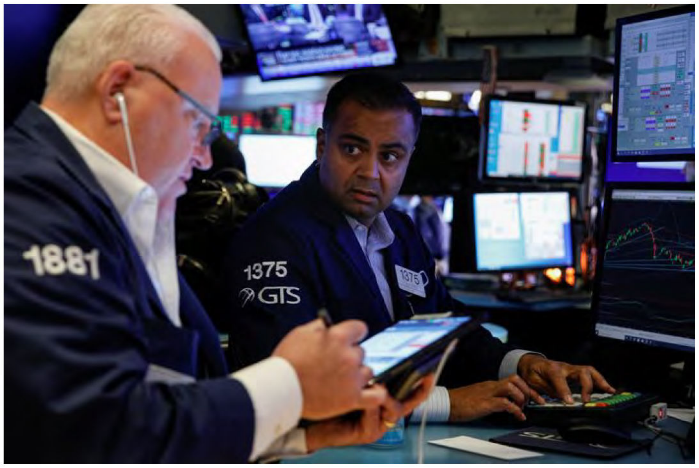
The pan-continental Stoxx Europe 600 fell 2.2% for its third straight session of losses.

Hong Kong’s Hang Seng Index rose 1.2% after signs of support from China’s central bank helped boost beaten-down shares of Chinese real-estate developers. The People’s Bank of China said late Monday it would “maintain the healthy development of the property market and safeguard the legitimate rights and interests of house buyers.”

Shares of Country Garden Holdings, China Vanke and China Overseas Land and Investment all jumped between 5% and 6%. China Evergrande Group, the ailing real estate giant that has fallen behind on a payment to international bondholders, rose more than 4%. Sunac China Holdings surged almost 15%, snapping two days of steep declines, after the property company played down a leaked plea for help from a local government, and said sales were good.

Meanwhile, Japan’s Nikkei Stock Average finished down 0.2%.

Higher bond yields drew investors into the U.S. dollar, which strengthened against major currencies from the euro to the Swiss franc. The WSJ Dollar Index, which tracks the currency against a basket of others, was up 0.4% and trading around a five-week high.



Some investors are recalibrating portfolios to prepare for the gradual end of ultra-easy monetary policies.

PHOTO: BRENDAN MCDERMID/REUTERS

—Xie Yu and Frances Yoon contributed to this article.

Write to Akane Otani at akane.otani@wsj.com and Will Horner at william.horner@wsj.com

Appeared in the September 29, 2021, print edition as 'Stocks Dive as Bond Yields Draw Technology Investors.'

SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

APPLICATION OF EL PASO	§	BEFORE THE STATE OFFICE
ELECTRIC COMPANY TO CHANGE	§	OF
RATES	§	ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
CITY OF EL PASO'S SEVENTEENTH REQUEST FOR INFORMATION
QUESTION NOS. CEP 17-1 THROUGH CEP 17-23

CEP 17-5:

Reference the Rebuttal testimony of Jennifer E. Nelson at 19 footnote 44 Please provide a copy of the press release referenced.

RESPONSE:

Please see CEP 17-5, Attachment 1.

Preparer: Jennifer E. Nelson Title: Assistant Vice President –Concentric Energy Advisers

Sponsor: Jennifer E. Nelson Title: Assistant Vice President – Concentric Energy Advisers

Duke Energy partners with GIC to secure minority investment in Duke Energy Indiana, increases long-term EPS growth rate

January 28, 2021

Share This Story

- **GIC to acquire 19.9 percent minority interest in Duke Energy Indiana for total of $2.05 billion; Duke Energy to remain majority owner and sole operator of DEI.**
- **Company announces 2021 adjusted EPS guidance range of $5.00 to $5.30.**
- **Attractive valuation and efficient form of financing supports increased long-term adjusted EPS growth rate of 5 to 7% through 2025, based off midpoint of 2021 range.**
- **Innovative two-stage closing replaces planned common equity in five-year plan and funds increased $58 to $60 billion capital plan.**

CHARLOTTE, N.C. – Duke Energy (NYSE: DUK), alongside GIC, today announced that it has entered into a definitive agreement for an acquisition of a 19.9 percent interest in Duke Energy Indiana (DEI), a subsidiary of Duke Energy, by an affiliate of GIC Private Limited, Singapore's sovereign wealth fund and an experienced investor in U.S. infrastructure.

Duke Energy today also announced its 2021 adjusted earnings per share (EPS) guidance range of $5.00 to $5.30. The transaction with GIC bolsters the company's growth potential and supports its increased long-term adjusted EPS growth rate of 5 to 7% through 2025, based off of a 2021 adjusted EPS midpoint of $5.15. This is up from the previously stated 4 to 6% rate.

Under the terms of the agreement, GIC will acquire a 19.9 percent indirect minority interest in Duke Energy Indiana for a total purchase price of $2.05 billion, a significant premium to Duke Energy's current public equity valuation.

Proceeds from the transaction will fund Duke Energy's increased $58 to $60 billion capital plan – a five-year plan that will accelerate its clean energy transition – and redeploy capital to support increased growth investments within its portfolio of regulated utilities. With this source of capital and increased financial strength, Duke Energy will continue providing reliable service and investing in important energy infrastructure while maintaining affordable rates for customers.

Given the innovative transaction structure, Duke Energy will receive proceeds in two, separate phases to efficiently align with the company's capital needs. The transaction allows Duke Energy to forego its previously announced plan to raise $1 billion of common equity.

Duke Energy will continue to operate DEI with its best-in-class workforce and will remain the majority owner, with an 80.1 percent stake in the business.

"We are pleased to have GIC as a long-term investor in DEI," said Lynn Good, Duke Energy's chair, president and chief executive officer. "This agreement with GIC allows Duke Energy to not only partner with a highly respected global investor, it also strengthens our confidence as we increase our long-term adjusted EPS growth rate to 5 to 7 percent. With this agreement, Duke Energy is well positioned to effectively finance our robust investment plan in a clean energy future and continue delivering sustainable value to our investors."

"Our agreement with GIC highlights the value and growth potential of DEI and recognizes the continued hard work and commitment of our people," said Stan Pinegar, DEI state president. "Delivering safe and reliable service to our customers and serving our communities remains our top priority."

Ang Eng Seng, GIC's Chief Investment Officer of Infrastructure, said, "As a long-term investor, GIC strongly believes that companies focused on meaningful sustainability practices will create better risk-adjusted returns over the long term. Duke Energy's proven management team and clear commitment to a clean energy transition make this an attractive partnership opportunity for GIC. This capital will help create long-term value by directly supporting Duke Energy's ability to capitalize on their stated ESG and decarbonization goals. We look forward to a successful transaction and long-term investment."

Transaction structure

The $2.05 billion in proceeds will be received in a staggered, two-phase closing, structured in evenly split payments. The first closing is expected to occur in the second quarter of 2021. Under the terms of the agreement, Duke Energy has the discretion to determine the timing of the second closing, but it will occur no later than January 2023.

GIC will invest in a newly formed intermediate holding company of which DEI will be a wholly owned subsidiary. GIC will receive certain limited rights commensurate with the minority stake.

The transaction is subject to customary closing conditions, including approval from the Federal Energy Regulatory Commission (FERC) and completion of review by the Committee on Foreign Investment in the United States (CFIUS).

J.P. Morgan Securities LLC served as Duke Energy's lead financial advisor, and Centerview Partners also served as a financial advisor. Skadden, Arps, Slate, Meagher & Flom LLP served as Duke Energy's legal advisor.

Barclays served as GIC's exclusive financial advisor. Sidley Austin LLP served as GIC's lead legal advisor alongside Steptoe & Johnson LLP and Ice Miller LLP.

Duke Energy

Duke Energy (NYSE: DUK), a Fortune 150 company headquartered in Charlotte, N.C., is one of the largest energy holding companies in the U.S. It employs 29,000 people and has an electric generating capacity of 51,000 megawatts through its regulated utilities and 2,300 megawatts through its nonregulated Duke Energy Renewables unit.

Duke Energy is transforming its customers' experience, modernizing the energy grid, generating cleaner energy and expanding natural gas infrastructure to create a smarter energy future for the people and communities it serves. The Electric Utilities and Infrastructure unit's regulated utilities serve 7.8 million retail electric customers in six states: North Carolina, South Carolina, Florida, Indiana, Ohio and Kentucky. The Gas Utilities and Infrastructure unit distributes natural gas to 1.6 million customers in five states: North Carolina, South Carolina, Tennessee, Ohio and Kentucky. The Duke Energy Renewables unit operates wind and solar generation facilities across the U.S., as well as energy storage and microgrid projects.

Duke Energy was named to Fortune's 2020 "World's Most Admired Companies" list and Forbes' "America's Best Employers" list. More information about the company is available at duke-energy.com. The Duke Energy News Center contains news releases, fact sheets, photos, videos and other materials. Duke Energy's illumination features stories about people, innovations, community topics and environmental issues. Follow Duke Energy on Twitter, LinkedIn, Instagram and Facebook.

GIC

GIC is a leading global investment firm established in 1981 to manage Singapore's foreign reserves. As a disciplined long-term value investor, GIC is uniquely positioned for investments across a wide range of asset classes, including equities, fixed income, private equity, real estate and infrastructure. GIC invests through funds and directly in companies, partnering with its fund managers and management teams to help world-class businesses achieve their objectives. GIC has investments in over 40 countries and has been investing in emerging markets for more than two decades. Headquartered in Singapore, GIC employs over 1,700 people across 10 offices in key financial cities worldwide. For more information about GIC, please visit www.gic.com.sg.

Non-GAAP Reconciliation

Duke Energy Corporation's (Duke Energy) materials for the GIC Investment in Duke Energy Indiana include a reference to the forecasted 2021 adjusted EPS guidance range of $5.00 to $5.30 per share, with a midpoint of approximately $5.15 per share. The materials also reference the long-term range of annual growth of 5% - 7% off the midpoint of the 2021 adjusted EPS guidance range, revised up from 4% - 6%. The forecasted adjusted EPS is a non-GAAP financial measure as it represents basic EPS available to Duke Energy Corporation common stockholders, adjusted for the per share impact of special items. Special items represent certain charges and credits, which management believes are not indicative of Duke Energy's ongoing performance.

Management believes the presentation of adjusted EPS provides useful information to investors, as it provides them with an additional relevant comparison of Duke Energy's performance across periods. Management uses this non-GAAP financial measure for planning and forecasting and for reporting financial results to the Duke Energy Board of Directors, employees, stockholders, analysts and investors. Adjusted EPS is also used as a basis for employee incentive bonuses.

The most directly comparable GAAP measure for adjusted EPS is reported basic EPS available to Duke Energy Corporation common stockholders. Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items for future periods, such as legal settlements, the impact of regulatory orders or asset impairments.

Forward-Looking Information

This document includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are based on management's beliefs and assumptions and can often be identified by terms and phrases that include "anticipate," "believe," "intend," "estimate," "expect," "continue," "should," "could," "may," "plan," "project," "predict," "will," "potential," "forecast," "target," "guidance," "outlook" or other similar terminology. Various factors may cause actual results to be materially different than the suggested outcomes within forward-looking statements; accordingly, there is no assurance that such results will be realized. For details on the uncertainties that may cause our actual future results to be materially different than those expressed in our forward-looking statements, see our 2019 Form 10-K and Quarterly Reports on Form 10-Q filed with the SEC and available at the SEC's website at sec.gov. In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than described. Forward-looking statements speak only as of the date they are made. Duke Energy expressly disclaims an obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise.

Duke Energy media contact: Catherine Butler
800.559.3853

Duke Energy analysts contact: Jack Sullivan
980.373.3564

GIC media contact: Katy Conrad
212.856.2407

Related Stories

Duke Energy designates Nov. 1 as Power Plant Worker Appreciation Day, recognizing those who provide one of life's essential services

Duke Energy Foundation awards $190,000 in grants to support environmental initiatives in Indiana communities

Duke Energy helps four Indiana communities prepare sites to bring local investment, jobs

Related Tags

Indiana, Financial News, Corporate

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SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

APPLICATION OF EL PASO	§	BEFORE THE STATE OFFICE
ELECTRIC COMPANY TO CHANGE	§	OF
RATES	§	ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
CITY OF EL PASO'S SEVENTEENTH REQUEST FOR INFORMATION
QUESTION NOS. CEP 17-1 THROUGH CEP 17-23

CEP 17-6:

Reference the Rebuttal testimony of Jennifer E. Nelson at 20 footnote 45, Please provide a copy of the Form 10-k referenced.

RESPONSE:

Please see CEP 17-6, Attachment 1.

Preparer: Jennifer E. Nelson Title: Assistant Vice President – Concentric Energy Advisers

Sponsor: Jennifer E. Nelson Title: Assistant Vice President – Concentric Energy Advisers

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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

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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

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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.

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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

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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).

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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.

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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

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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

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.

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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.

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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	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	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.

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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

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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.

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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

(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	☑	☑				☑	

(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.

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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.

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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.

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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;

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- 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.

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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.

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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.

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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%

(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		

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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.

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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.

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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.

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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.

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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.

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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.

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

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

ITEM 4. MINE SAFETY DISCLOSURES

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

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INFORMATION ABOUT OUR EXECUTIVE OFFICERS

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

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

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

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

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

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

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

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PART II

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

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

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

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

UNREGISTERED SECURITIES ISSUED

There were no unregistered securities sold during 2020.

ISSUER PURCHASES OF EQUITY SECURITIES

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

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

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

ITEM 6. SELECTED FINANCIAL DATA

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

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

Executive Summary

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

The Company has provided energy and served customers for 137 years, since the 1883 gold rush days in Deadwood, South Dakota. Throughout our history, the common thread that unites the past to the present is our commitment to serve our customers and communities. Our strategic focus has not changed in over a century - serving customers with affordable, reliable and safe energy and being strong environmental stewards. Our strategy today continues that emphasis on serving customers and being responsive to the people and communities we serve. Customer expectations are rapidly changing with the advancement of technology and customers are demanding simpler, faster and more convenient solutions to their energy needs. Customers and other stakeholders are demanding cleaner energy solutions to address concerns around carbon emissions. In this rapidly changing energy environment, we are *Ready* to serve.

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

Key Elements of our Business Strategy

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

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

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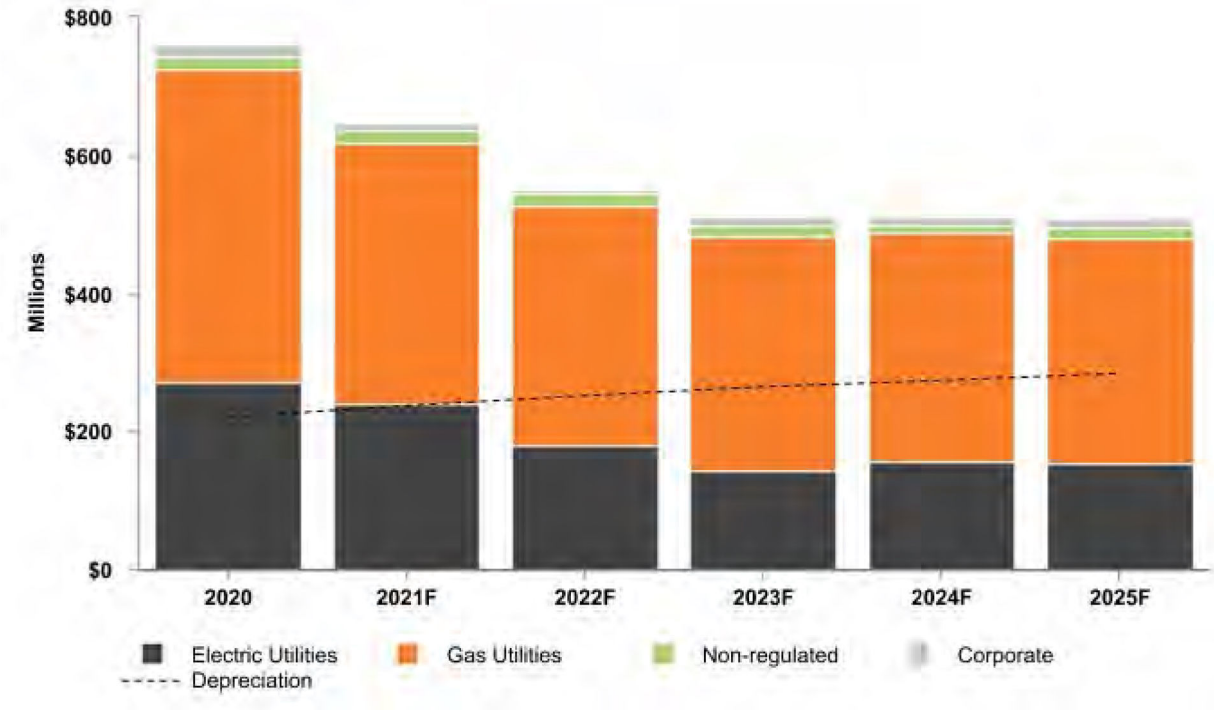
As of December 31, 2020, we estimate our five-year capital investment to be approximately $2.7 billion, with most of that investment targeted toward upgrading existing utility infrastructure and to support customer and community growth needs. Our actual 2020 and forecasted capital expenditures and depreciation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



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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Prospective Information

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

Company Highlights

February 2021 Weather Event

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

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

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

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

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

COVID-19 Pandemic

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

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

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

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

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

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

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

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

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

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

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

Business Segment Highlights and Corporate Activity

Electric Utilities

- On November 30, 2020, South Dakota Electric and Wyoming Electric completed and placed in service the Corriedale project. The 52.5 MW wind project is jointly owned by the two electric utilities to deliver renewable energy for large commercial, industrial and governmental agency customers under the Renewable Ready program.

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

- On September 23, 2020, Colorado Electric received approval from the CPUC for its request for approval of its preferred solar bid in support of its Renewable Advantage program. The program plans to add up to 200 MW of renewable energy in Colorado by the end of 2023.

- On July 10, 2020, Wyoming Electric set a new all-time peak load of 271 MW, surpassing the previous peak of 265 MW set in July 2019.

- On May 5, 2020, citizens in Pueblo, Colorado voted overwhelmingly to retain Colorado Electric as its electric utility provider by 75.6% of votes cast. The current franchise agreement continues through 2030.

Gas Utilities

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

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

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

- On December 27, 2020, gas service to approximately 3,500 Colorado Gas customers in Aspen, Colorado was disrupted due to vandalism. Gas services were restored to nearly all customers by December 30, 2020 with the remaining few restored by January 1, 2021. Colorado Gas employees were joined by Black Hills Energy technicians from other states, as well as contractors and other utilities, to successfully restore service despite challenging weather, temperatures, additional precautions due to COVID-19 and significant travel by many to reach Aspen.

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

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

Power Generation

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

Corporate and Other

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

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

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

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Results of Operations

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

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

Consolidated Summary and Overview

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

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

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2020 Compared to 2019

The variance to the prior year included the following:

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

Segment Operating Results

A discussion of operating results from our business segments follows.

Non-GAAP Financial Measure

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

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

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

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Electric Utilities

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

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

2020 Compared to 2019

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

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

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

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

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

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Operating Statistics

For the year ended December 31,	Electric Revenue (in thousands) 2020	2019	2018	Quantities Sold (MWh) 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			

For the year ended December 31,	Electric Revenue (in thousands) 2020	2019	2018	Gross Margin (non-GAAP) (in thousands) 2020	2019	2018	Quantities Sold (MWh) [(b)] 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.

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

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

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

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

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

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

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

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Gas Utilities

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

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

2020 Compared to 2019

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

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

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

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

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

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Operating Statistics

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

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

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

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

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Power Generation

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

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

2020 Compared to 2019

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

Operating Statistics

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

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

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

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

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

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

Mining

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

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

2020 Compared to 2019

Adjusted operating income was comparable to the prior year.

Operating Statistics

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

Corporate and Other

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

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

2020 Compared to 2019

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

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

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

2020 Compared to 2019

Interest Expense

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

Impairment of Investment

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

Other Income (Expense)

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

Income Tax Benefit (Expense)

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

Liquidity and Capital Resources

OVERVIEW

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

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

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

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

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

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

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

CASH FLOW ACTIVITIES

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

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

2020 Compared to 2019

Operating Activities:

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

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

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Investing Activities:

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

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

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

Financing Activities:

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

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

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

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

CAPITAL SOURCES

Revolving Credit Facility and CP Program

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

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

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

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

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

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

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

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

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

Utility Money Pool

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

Long-term Debt

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

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

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

Covenant Requirements

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

Equity

Shelf Registration

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

ATM

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

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

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Future Financing Plans

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

CREDIT RATINGS

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

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

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

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

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

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

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

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

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

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CAPITAL REQUIREMENTS

Capital Expenditures

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

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

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

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

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

Unconditional Purchase Obligations

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

Defined Benefit Pension Plan

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

Common Stock Dividends

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

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

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

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

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

Collateral Requirements

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

Guarantees

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

Critical Accounting Policies Involving Significant Estimates

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

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

Regulation

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

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

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

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

Goodwill

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

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

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

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

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

Pension and Other Postretirement Benefits

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

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

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

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

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

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

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

Income Taxes

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

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

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

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

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

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New Accounting Pronouncements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

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

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

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

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

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

Commodity Price Risk

Electric and Gas Utilities

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

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

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

Wholesale Power

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

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

Black Hills Energy Services

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

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

Interest Rate Risk

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

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

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

Credit Risk

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

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

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

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control over Financial Reporting

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

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

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

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

Black Hills Corporation

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Financial Statements

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

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

Basis for Opinion

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

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

Critical Audit Matter

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

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

Critical Audit Matter Description

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

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

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

How the Critical Audit Matter Was Addressed in the Audit

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

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

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 26, 2021

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