SECTION 1, RULE 004.02 GENERAL INFORMATION

Application Section & Exhibit	Rule Ref	Testimony Exhibit Cross Reference	Topic	Witness
General Information				
Section 1, Exhibit A	004.02A		Base Year Test Year	Amdor
Section 1, Exhibit B	004.02B		Case Drivers	Amdor
Section 1, Exhibit B2	004.02B		Customer Impacts	Sullivan
Section 1, Exhibit C	004.02C	MCC-2 Stmt M	Financial Summary	Clevinger
Section 1, Exhibit D	004.02D		Corporate Structure	Amdor
Section 1, Exhibit E	004.02E	MCC-2 Stmt A, Stmt B	Financial Statements	Clevinger
Section 1, Exhibit F	004.02F		Annual Report	Amdor
Section 1, Exhibit G	004.02G		Witness List	Amdor
Rate Base Schedules				
Section 2, Exhibit A	004.03A	MCC-2 Stmt D, Stmt E, & Sch M-1	Rate Base Schedules	Clevinger
Section 2, Exhibit A1	004.03A1	MCC-2 Stmt E	Utility Plant - Depr.	Clevinger
Section 2, Exhibit A2	004.03A2	MCC-2 Stmt F & Lead Lag Study	Working Capital	Clevinger
Section 2, Exhibit A3	004.03A3	MCC-2 Sch M-1	Other Rate Base Items	Clevinger
Section 2, Exhibit B	004.03B	MCC-2 Stmt D, Stmt E, & Sch M-1	Allocated Rate Base	Clevinger
Section 2, Exhibit C	004.03C	KMJ-4	2020 Capital Additions	Jarosz
Operating Expense Schedules				
Section 2, Exhibit A	004.04A	MCC-2 Stmt H	Operating Expenses	Clevinger
Section 2, Exhibit B	004.04B		Legislative Advocacy	Clevinger
Section 2, Exhibit C	004.04C		Political Candidates	Clevinger
Section 2, Exhibit D	004.04D		Political Religious Causes	Clevinger
Section 2, Exhibit E	004.04E		Memberships and Dues	Clevinger
Section 2, Exhibit F	004.04F		Affiliate Transactions	Clevinger
Section 2, Exhibit G	004.04G		Cost Allocation Manuel	Clevinger
Rate of Return and Cost of Capital Schedules				
Section 2, Exhibit 5A	004.05A	MCC-2 Stmt G & Sch G-1	Cost of Capital / ROR	Clevinger
Section 2, Exhibit 5B	004.05B	MCC-2 Stmt G & Sch G-1	Cost of Capital / ROR	Clevinger

Application Section & Exhibit	Rule Ref	Testimony Exhibit Cross Reference	Topic	Witness
Revenue Schedules				
Section 3, Exhibit A	004.06A		Rate Rev. unadjusted	Hyatt
Section 3, Exhibit B	004.06B		Rate Rev. normalized	Hyatt
Section 3, Exhibit C	004.06B1		Using Current Rate	Hyatt
Section 3 - DNH-7	004.06B2	DNH-7	Using Proposed Rates	Hyatt
Class Cost of Service Study				
Section 4, Exhibit A	004.07		Class Cost of Service Study	Sullivan
Section 4, Exhibit B	004.07		Class Cost of Service Study	Sullivan
Prefiled Direct Testimony and Exhibits				
Section 5 - Direct Testimony	004.08		Testimony and Exhibits	Various
Tariffs				
Section 6 - Tariffs (Clean & Red-Lined)	No rule reference		Clean and Redlined Tariffs	Frost
Workpapers				
Section 7 - Workpapers	004.01C		Workpapers	Various

Base Year

The Base Year is the twelve months ended December 31, 2019.

Test Year

In accordance with Commission Rule 001.01R, the Test Year is the Base Year ended December 31, 2019, adjusted for known and measurable changes occurring within one year of the end of the Base Year as well as applying normalization adjustments, as required by the Act, and an annualized adjustment to correct for out-of-period billing entries. The Company is proposing to include in rate base Capital Additions Projects that went into service after the end of the Base Year and through the end of 2020.

241 Neb. Admin. Code. Ch. 9, Rules 001.01R and 004.02A

A description of the proposed revenue increase, number and classifications of affected rate payers, average per rate payer, volumes per classifications, and reasons for proposed increase.
241 Neb. Admin. Code. Ch. 9., Rule 004.02B.

Description of Revenue Requirement

As a result of consolidation of BH Gas Utility and BH Gas Distribution, BH Nebraska Gas is experiencing a revenue deficiency of $17,296,140 that will be addressed in this rate review proceeding. Base Year for this Rate Review Application is January 1, 2019 through December 31, 2019. The Test Year adjusts the Base Year for known for known and measurable changes, as well as applying normalization adjustments, as required by the Act, and an annualized adjustment to correct for out-of-period billing entries. The Company is proposing to include in rate base capital projects that went into service after the end of the Base Year and through the end of 2020.

Revenue Deficiency	Capital Structure	ROE	Cost of Debt	Weighted Cost of Capital
$17.3 million	50% Equity/50% Debt	10%	4.11%	7.06%

Number and Classification of Affected Rate Payers

Proposed Customer Class	2020
Residential	255,678
Commercial	32,398
Total	288,076

Average Per Ratepayer Increase
Average Residential Customer Bill Impacts

BH Gas Utility Residential Winter	BH Gas Distribution Residential Winter	BH Gas Utility Residential Summer	BH Gas Distribution Residential Summer
$5.61/mo. increase	$.66/mo. increase	9.26/mo. increase	$0.65/mo. decrease
7%/mo. Higher	1% Higher	33%/mo. Higher	2% Lower

Average Small Commercial Customer Bill Impacts

BH Gas Utility Small Commercial Winter	BH Gas Distribution Small Commercial Winter	BH Gas Utility Small Commercial Summer	BH Gas Distribution Small Commercial Summer
$15.89/mo. increase	$14.21/mo. increase	25.56/mo. increase	$7.23/mo. increase
4%/mo. Higher	4% Higher	23%/mo. Higher	6% Higher

Average Large Commercial Customer Bill Impacts

BH Gas Utility Large Commercial Winter	BH Gas Distribution Large Commercial Winter	BH Gas Utility Large Commercial Summer	BH Gas Distribution Large Commercial Summer
$(33.37)/mo. decrease	$(42.77)/mo. decrease	$8.95/mo. increase	$(73.31)/mo. decrease
2%/mo. Lower	3% Lower	2%/mo. Higher	12% Lower

Reasons For Proposed Increase:

1. **Capital Infrastructure Project Investment Recovery**

BH Gas Utility and BH Gas Distribution each made significant capital investment in their gas distribution system infrastructure since the last Rate Review Applications for either BH Gas Utility or BH Gas Distribution ("Capital Infrastructure Projects"). In fact, BH Nebraska Gas has increased its jurisdictional rate base by approximately $322 million since the last rate review proceedings for BH Gas Utility and BH Gas Distribution. Those Capital Infrastructure Projects investments were made to improve the respective gas distribution systems of BH Gas Utility or BH Gas Distribution. The combined rate base of BH Gas Utility and BH Gas Distribution at the end of the Base Year (i.e., 12/31/2019) is approximately $526 million.

a. **Rolled-in Capital Investment**. A significant amount of the Capital Infrastructure Projects investment was made by either BH Gas Utility and BH Gas Distribution in system safety infrastructure (i.e., "Integrity" projects). That investment has been recovered through either a Pipeline Replacement Charge or an SSIR Charge.

On the other hand, significant investment in other Capital Infrastructure Projects (i.e., Growth, Reliability, or General Plant projects) has not yet been incorporated into tariff rates by BH Gas Utility or BH Gas Distribution.

All Capital Infrastructure Project investments will be included (i.e., rolled into Rate Base) into tariff rates through this Rate Review Application. The Rolled-in Capital Infrastructure investment is included in this Rate Review Application as Exhibit No. MCC-2, Statement D and Schedules D-1, D-2, and D-3 attached to the testimony of Mr. Clevinger. See also Statement M.

b. **2020 Capital Additions Investment**. BH Nebraska Gas will invest approximately $102 million in Capital Additions during 2020. The total state rate base of BH Gas Utility will increase to $586 million by the end of this rate review proceeding. BH Gas Utility and BH Gas Distribution invested in numerous Growth, Integrity, Reliability, and General Plant Capital Investment Projects. The rate base will be approximately

$586 million. The 2020 Capital Additions are included in this Rate Review Application as Exhibit No. KMJ-4 attached to the testimony of Mr. Jarosz.

c. **2021 SSIR Capital Investment**. In 2021, BH Nebraska Gas proposed to invest $51 million in SSIR projects. The Application for the 2021 SSIR projects is included in this Rate Review Application as Exhibit No. JLB-5 attached to the testimony of Mr. Bennett.

d. **Five-Year Plan Capital Investment**. The Company plans on investing an additional $455 million (i.e. approximately $91 million average per/year) on Capital Infrastructure Projects over the next five years in BH Nebraska Gas. BH Nebraska Gas will spend approximately $50 million of the $91 million per year on programmatic System Safety Integrity Rider ("SSIR") projects.

The most important keys to this Rate Review Application for BH Nebraska Gas are:

a. Commission approval of the recovery of previously unrecovered gas system investment; and

b. Commission approval of the Company's proposed rate mechanisms to improve the safety and reliability of its gas distribution system.

2. **Pipeline Replacement Charge Renewal, SSIR Renewal, Extension, and other SSIR Modifications**

The Pipeline Replacement Charge and SSIR mechanisms are designed to (a) improve customer safety, (b) drive collaboration between the Commission, the Public Advocate and the Company, and (c) reduce regulatory lag. Recovery of required capital investment through a Pipeline Replacement Charge or SSIR Charge extends the time between Rate Review Applications.

Accordingly, another key to this rate review proceeding is (a) the renewal of the system safety mechanisms (i.e., Pipeline Replacement Charge and SSIR Charge), (b) extension of the SSIR mechanism to all Rate Areas, (c) modification of the SSIR's definition of eligible projects, categories, and criteria, (d) a change in the SSIR Surveillance Reports, and (e) modification of the SSIR mechanism to include recovery of Data Integrity Improvement Program ("DIIP") costs through the SSIR Charge.

BH Nebraska Gas proposes that future investment in system integrity projects be approved and recovered similar to the established SSIR mechanism process used currently by BH Gas Distribution.[1] BH Nebraska Gas also seeks to modify the current definition of eligible projects, SSIR Criteria and SSIR Categories to also include Reliability projects and Data Integrity

[1] The SSIR mechanism is in addition to the Pipeline Replacement Charge authorized by Neb. Rev. Stats. §§ 66-1864 through 66-1867.

Improvement Programs costs through the SSIR Charge. BH Nebraska Gas plans to continue making significant investment into the safety, resiliency, and reliability of its gas distribution system in Nebraska.

3. **Public Power Competition and High Efficiency Appliance Tool ("HEAT") Tariff**

BH Nebraska Gas faces constant and seemingly increased competition from public power districts in Nebraska. As demonstrated in the testimony of Dr. Rosenbaum, Mr. Frost, and Mr. Sullivan, competition from Nebraska's publicly owned power districts poses a significant threat to the operations of BH Nebraska Gas. Those competitive challenges come primarily in the form of low winter rates and electric appliance rebates.

Other competitive advantages for power districts come in the form of governmental protections, governmental immunities, lower tax burdens, different regulatory structures, and exclusive service areas.

BH Nebraska Gas needs to meet competition from Nebraska power districts in order to level the playing field and to provide its customers with valuable energy options. To that end, another key of this rate review proceeding is that BH Nebraska gas proposes to (a) adopt a rate design that will fairly compete with the Nebraska power districts, and (b) continue the High Efficiency Appliance Tool program that currently exists in BH Nebraska Gas Rate Area Five.

Based on the research conducted by Dr. Rosenbaum, BH Nebraska Gas further proposes to expand the HEAT Program to BH Nebraska Gas Rate Areas One, Two, and Three as well.

4. **Revenue Deficiency**

Revenue Deficiency	Capital Structure	ROE	Cost of Debt	Weighted Cost of Capital
$17.3 million	50% Equity/50% Debt	10%	4.11%	7.06%

5. **Statewide Consolidated Rates**

This Rate Review Application covers BH Nebraska Gas Rate Areas One, Two, Three (former BH Gas Utility rate areas), and Five (former BH Gas Distribution rate area).[2]

[2] Rate Area 4 is a designation of the Agricultural and High Volume non-jurisdictional transportation customers whose service is provided pursuant to Neb. Rev. Stat. § 66-1810. The rates, terms, and conditions of service for customers served under Rate Area 4 non-jurisdictional transportation customers are not subject to this filing other than allocation of costs between regulated and non-regulated customers. *See Tariff Sheet Nos. 20-27* for more detail regarding BH Nebraska Gas rate areas.

BH Nebraska Gas's Nebraska customers are served by common interstate natural gas pipeline systems.[3]

BH Nebraska Gas proposes uniform base rates for each customer class within the BH Nebraska Gas rate areas. As part of the statewide rate consolidation, BH Nebraska Gas proposes to either (a) raise the customer charges and establish block rates (a/k/a "Block Rate" rate design) or (b) increase its customer charge to cover all of its fixed costs (a/k/a "Straight-Fixed-Variable" rate design).

As explained in the testimony of Mr. Sullivan, the change in rate design is necessary to compete effectively with public power districts in Nebraska.

Although there is a difference in gas purchasing between Rate Areas One, Two, and Three (i.e., former BH Gas Utility Gas Cost Reconciliation mechanism) vs. Rate Area 5 (former BH Gas Distribution's Choice Gas Program), BH Nebraska Gas incurs similar costs to serve its gas distribution customers in BH Nebraska Gas Rate Areas One, Two, Three, and Five.

Therefore, subject to the Commission's approval of the general rate increase requested in this Rate Review Application, BH Nebraska Gas revises its effective tariff rate schedules in accordance with the Act so that BH Nebraska Gas's approved base rates for natural gas service will be applied equally within each of the jurisdictional rate areas. The proposed rate design is set forth below.

BH Nebraska Gas has designed its proposed rates to accomplish the following results: (1) standardization of rates between all jurisdictional rate areas; (2) simplicity; (3) fair apportionment of costs among various customer sizes; (4) an opportunity for BH Nebraska Gas to set rates which are reflective of its current cost structure and business conditions; (5) an opportunity to add stability to BH Nebraska Gas's rate structure; and (6) an opportunity to allow BH Nebraska Gas to meet competition from other energy providers.

[3] Northern Natural Gas Company ("NNG") and Tallgrass Interstate Gas Transmission ("TIGT") are primary interstate pipelines delivering interstate natural gas supplies to Black Hills Energy and its customers in Nebraska.

BH Nebraska Gas Recommended Rate Design (Block Rates)

	BH Gas Utility Current	BH Gas Distribution Current	BH Nebraska Gas Proposed
Residential Customer Charge	$13.50 per Month	$14.70 per Month	$15.45 per Month
Commercial Customer Charge	$18.50 per Month	$22.75 per Month	$31.10 per Month
Large Commercial Customer Charge	NA	$56.15 per Month	N/A
Residential Distribution Charge Tier 1	$.19500/Therm	$.04675/Therm First 20 Therms	$.59960/Therm First 20 Therms
Residential Distribution Charge Tier 2	N/A	$.1338/Therm Over 20 Therms	$.15000/Therm Over 20 Therms
Small Commercial Distribution Charge Tier 1	$.17245/Therm	$.4675/Therm First 40 Therms	$.59960 /Therm First 40 Therms
Small Commercial Distribution Charge Tier 2	N/A	$.1338 Therms Over 40 Therms	$.1500/Therm Over 40 Therms
Large Commercial Distribution Charge Tier 1	N/A	$.4675/Therm First 80 Therms	N/A
Large Commercial Distribution Charge Tier 2	N/A	$.4675/Therm Over 80 Therms	N/A

BH Nebraska Gas Alternate Rate Design
(Straight Fixed Variable)

	Alternate Customer Charge	Alternate Volumetric Charge
Residential	$22.81 per Month	$.1500/Therm
Commercial	$43.65 per Month	$.1500/Therm

6. **Covid-19 Pandemic**

The global Covid-19 Pandemic ("Pandemic") caused numerous devasting impacts to the health and well-being of people throughout the world. The public health and economy of Nebraska was also impacted significantly by this Pandemic. BH Nebraska Gas provides energy within 319 communities in Nebraska and is considered an essential service during the Pandemic.

BH Nebraska Gas is sensitive to the health, unemployment and other impacts caused by the recent pandemic. The Pandemic had several impacts on the customer safety and service provided by the Company. One of the many actions that BH Nebraska Gas took in response to managing its business operations during this Pandemic was to prudently balance the impact on customers as a result of filing this Rate Review Application with the financial stability of BH Nebraska Gas. Mr. Jarosz provides testimony on actions that the Company undertook in the interest of its customer safety, employee safety, and to help customers with financial impacts resulting from the Pandemic.

7. **Other Traditional Rate Review Issues**

In addition to the primary rate review drivers identified above, BH Nebraska Gas provides testimony and evidence in support of its Rate Review Application, tariffs, and other items that are within a general rate review. For example, as supported by the Direct Testimony of Tyler Frost, BH Nebraska Gas proposes tariff changes to establish uniform fees or charges for diversion of gas fees, late payment fees, connect, reconnect, and NSF. Those fees and charges are not currently standardized. Mr. Clevinger provides the Revenue Requirement Study used to determine the revenue deficiency in this case. Mr. Sullivan provides the Cost Allocation Manual currently used by BHSC for allocating costs to BH Nebraska Gas, and for designing rates. Mr. Klapperich discusses tax methodologies applied in the Rate Review Application. The areas of testimony for each witness is summarized in the table of witnesses below.

Black Hills Nebraska Gas, LLC
BILL IMPACTS - PROPOSED RATES
FOR THE PRO FORMA PERIOD ENDED DECEMBER 31, 2020

	A	B	C	D	E	F	G	H	I	J	K	L	M
		BH Gas Utility		**BH Gas Distribution**		**BH Gas Utility**				**BH Gas Distribution**			
		Residential		**Residential**		**Small Commercial**		**(Large Commercial)**		**Small Commercial**		**Large Commercial**	
Line No.	**Description**	**Typical Winter Bill**	**Typical Summer Bill**	**Typical Winter Bill**	**Typical Summer Bill**	**Typical Winter Bill**	**Typical Summer Bill**	**Typical Winter Bill**	**Typical Summer Bill**	**Typical Winter Bill**	**Typical Summer Bill**	**Typical Winter Bill**	**Typical Summer Bill**
1	1. Typical Monthly Usage	104	23	104	23	582	151	2,776	891	582	151	2,776	891
2	Therm Threshold	**20 Therms**		**20 Therms**		**40 Therms**		**80 Therms**		**40 Therms**		**80 Therms**	
3	Tier 1 Therms	20	20	20	20	40	40	80	80	40	40	80	80
4													
5	Therm Threshold	**>20 Therms**		**>20 Therms**		**>40 Therms**		**>80 Therms**		**>40 Therms**		**>80 Therms**	
6	Tier 2 Therms	84	3	84	3	542	111	2,696	811	542	111	2,696	811
7													
8	2. Current Rates												
9	Cost of Gas - Weighted Average $/Therm	0.42474	0.42474	0.42474	0.42474	0.42337	0.42337	0.42337	0.42337	0.42337	0.42337	0.42337	0.42337
10													
11	Volumetric Charge - $/Therm	0.19500	0.19500			0.17245	0.17245	0.17245	0.17245				
12													
13	Therm Threshold			**20 Therms**						**40 Therms**		**80 Therms**	
14	Distribution Charge Tier 1			0.46750	0.46750					0.46750	0.46750	0.46750	0.46750
15													
16	Therm Threshold			**>20 Therms**						**>40 Therms**		**>80 Therms**	
17	Distribution Charge Tier 2			0.13380	0.13380					0.13380	0.13380	0.13380	0.13380
18													
19	Monthly Charge -$/Month												
20	Heat Program -$/Month			0.30	0.30					0.30	0.30	0.30	0.30
21	NPSC Charge -$/Month	0.15	0.15	0.14	0.14	0.15	0.15	0.15	0.15	0.14	0.14	0.14	0.14
22	Pipeline Integrity (PRC) -$/Month			0.00	0.00					0.00	0.00	0.00	0.00
23	Safety & Integrity (SSIR)			3.65	3.65					7.76	7.76	53.54	53.54
24	Fuel Line Replacement Charge -$/Month	0.13	0.13			0.32	0.32	0.32	0.32				
25	Pipeline Replacement Charge -$/Month	0.37	0.37			1.16	1.16	1.16	1.16				
26													
27	Customer Charge - $/Month	13.50	13.50	14.70	14.70	18.50	18.50	18.50	18.50	22.75	22.75	56.15	56.15
28													
29	3. Typical Monthly Bill - Current Rates $	78.60	28.40	83.55	38.31	366.90	110.10	1,674.12	551.00	368.57	128.43	1,683.52	633.26

Black Hills Nebraska Gas, LLC
BILL IMPACTS - COST-BASED RATES
FOR THE PRO FORMA PERIOD ENDED DECEMBER 31, 2020

	A	B	C	D	E	F	G	H	I	J	K	L	M
		BH Gas Utility		**BH Gas Distribution**		**BH Gas Utility**				**BH Gas Distribution**			
		Residential		**Residential**		**Small Commercial**		**(Large Commercial)**		**Small Commercial**		**Large Commercial**	
Line No.	**Description**	**Typical Winter Bill**	**Typical Summer Bill**	**Typical Winter Bill**	**Typical Summer Bill**	**Typical Winter Bill**	**Typical Summer Bill**	**Typical Winter Bill**	**Typical Summer Bill**	**Typical Winter Bill**	**Typical Summer Bill**	**Typical Winter Bill**	**Typical Summer Bill**
30	4. Cost-Based Rates												
31	Cost of Gas - $/Therm	0.42474	0.42474	0.42474	0.42474	0.42337	0.42337	0.42337	0.42337	0.42337	0.42337	0.42337	0.42337
32													
33	Volumetric Charge - $/Therm												
34	Therm Threshold	**20 Therms**		**20 Therms**		**40 Therms**		**40 Therms**		**40 Therms**		**40 Therms**	
35	Distribution Charge Tier 1	0.12090	0.12090	0.12090	0.12090	0.11810	0.11810	0.11810	0.11810	0.11810	0.11810	0.11810	0.11810
36													
37	Therm Threshold	**>20 Therms**		**>20 Therms**		**> 40 Therms**		**> 40 Therms**		**> 40 Therms**		**> 40 Therms**	
38	Distribution Charge Tier 2	0.12090	0.12090	0.12090	0.12090	0.11810	0.11810	0.11810	0.11810	0.11810	0.11810	0.11810	0.11810
39													
40	Customer Charge - $/Month	24.50	24.50	24.50	24.50	54.00	54.00	54.00	54.00	54.00	54.00	54.00	54.00
41													
42	5. Typical Monthly Bill - Cost-Based Rates - $	81.25	37.05	81.25	37.05	369.13	135.76	1,557.11	536.45	369.13	135.76	1,557.11	536.45
43													
44	6. Difference from Current Rates - $	2.64	8.65	(2.31)	(1.26)	2.24	25.66	(117.01)	(14.56)	0.56	7.33	(126.41)	(96.81)
45	7. Change from Current Rates - %	3%	30%	-3%	-3%	1%	23%	-7%	-3%	0%	6%	-8%	-15%

Black Hills Nebraska Gas, LLC
BILL IMPACTS - PROPOSED RATES
FOR THE PRO FORMA PERIOD ENDED DECEMBER 31, 2020

	A	B	C	D	E	F	G	H	I	J	K	L	M
		BH Gas Utility		BH Gas Distribution		BH Gas Utility				BH Gas Distribution			
		Residential		Residential		Small Commercial		(Large Commercial)		Small Commercial		Large Commercial	
Line No.	Description	Typical Winter Bill	Typical Summer Bill	Typical Winter Bill	Typical Summer Bill	Typical Winter Bill	Typical Summer Bill	Typical Winter Bill	Typical Summer Bill	Typical Winter Bill	Typical Summer Bill	Typical Winter Bill	Typical Summer Bill
46	8. Proposed Rates												
47	Cost of Gas - $/Therm	0.42474	0.42474	0.42474	0.42474	0.42337	0.42337	0.42337	0.42337	0.42337	0.42337	0.42337	0.42337
48													
49	Volumetric Charge - $/Therm												
50	Therm Threshold	**20 Therms**		**20 Therms**		**40 Therms**		**40 Therms**		**40 Therms**		**40 Therms**	
51	Distribution Charge Tier 1	0.59960	0.59960	0.59960	0.59960	0.59960	0.59960	0.59960	0.59960	0.59960	0.59960	0.59960	0.59960
52													
53	Therm Threshold	**>20 Therms**		**>20 Therms**		**> 40 Therms**		**> 40 Therms**		**> 40 Therms**		**> 40 Therms**	
54	Distribution Charge Tier 2	0.15000	0.15000	0.15000	0.15000	0.15000	0.15000	0.15000	0.15000	0.15000	0.15000	0.15000	0.15000
55													
56	Customer Charge - $/Month	15.45	15.45	15.45	15.45	31.10	31.10	31.10	31.10	31.10	31.10	31.10	31.10
57													
58	9. Typical Monthly Bill - Proposed Rates - $	84.21	37.66	84.21	37.66	382.78	135.66	1,640.75	559.95	382.78	135.66	1,640.75	559.95
59													
60	10. Difference from Current Rates - $	5.61	9.26	0.66	(0.65)	15.89	25.56	(33.37)	8.95	14.21	7.23	(42.77)	(73.31)
61	11. Change from Current Rates - %	7%	33%	1%	-2%	4%	23%	-2%	2%	4%	6%	-3%	-12%

Black Hills Nebraska Gas, LLC
BILL IMPACTS - ALTERNATE RATES
FOR THE PRO FORMA PERIOD ENDED DECEMBER 31, 2020

	A	B	C	D	E	F	G	H	I	J	K	L	M
		BH Gas Utility		BH Gas Distribution		BH Gas Utility				BH Gas Distribution			
		Residential		Residential		Small Commercial		(Large Commercial)		Small Commercial		Large Commercial	
Line No.	Description	Typical Winter Bill	Typical Summer Bill	Typical Winter Bill	Typical Summer Bill	Typical Winter Bill	Typical Summer Bill	Typical Winter Bill	Typical Summer Bill	Typical Winter Bill	Typical Summer Bill	Typical Winter Bill	Typical Summer Bill
62	12. Alternate Rates												
63	Cost of Gas - $/Therm	0.42474	0.42474	0.42474	0.42474	0.42337	0.42337	0.42337	0.42337	0.42337	0.42337	0.42337	0.42337
64													
65	Volumetric Charge - $/Therm												
66	All Therms	0.15000	0.15000	0.15000	0.15000	0.1500	0.1500	0.1500	0.1500	0.1500	0.1500	0.1500	0.1500
67													
68	Customer Charge - $/Month	22.81	22.81	22.81	22.81	43.65	43.65	43.65	43.65	43.65	43.65	43.65	43.65
69													
70	13. Typical Monthly Bill - Alternate Rates - $	82.58	36.03	82.58	36.03	377.35	130.23	1,635.32	554.52	377.35	130.23	1,635.32	554.52
71													
72	14. Difference from Current Rates - $	3.98	7.63	(0.97)	(2.28)	10.45	20.13	(38.80)	3.52	8.78	1.80	(48.20)	(78.74)
73	15. Change from Current Rates - %	5%	27%	-1%	-6%	3%	18%	-2%	1%	2%	1%	-3%	-12%

A Financial Summary showing aggregate amounts for rate base operating expenses, and rate of return for the base year and test year plus operating revenue calculated using natural gas rates in effect and natural gas rates as proposed

The Financial summary for the most recent fiscal year (2019) is replicated from Statement M of the Revenue Requirement Study.

241 Neb. Admin. Code. Ch. 9., Rule 004.02C

BLACK HILLS NEBRASKA GAS, LLC
OVERALL REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2020

Line No.	Description	Reference	(a) Base Year Per Books	(b) Pro Forma Adjustments	(c) (a) + (b) Adjusted Total	(d) Additional Revenue Required	(e) (c) + (d) Adjusted Rate of Return
1	**Operating Revenue**						
2	Total Sales - Jurisdictional	Stmt I Ln.6	$ 190,360,412	$ (75,060,842)	$ 115,299,571	$ 11,733,366	$ 127,032,937
3	Total Sales - Non Jurisdictional	Stmt I Ln.13	24,263,074	1,748,793	26,011,867	-	26,011,867
4	Other Operating Revenue	Stmt I Ln.23	4,280,727	1,022,704	5,303,431	-	5,303,431
5	Total Operating Revenue		$ 218,904,213	$ (72,289,345)	$ 146,614,869	$ 11,733,366	$ 158,348,235
6							
7	**Operating Expenses**						
8	Operation and Maintenance	Stmt H Ln.164	$ 143,067,314	$ (67,615,528)	$ 75,451,786	$ -	$ 75,451,786
9	Depreciation	Stmt J Ln.20(b)	24,036,687	(667,038)	23,369,648	-	23,369,648
10	Taxes Other Than Income Tax	Stmt L Ln.44	5,875,853	1,210,099	7,085,952	-	7,085,952
11	Total Operating Expenses		$ 172,979,853	$ (67,072,467)	$ 105,907,386	$ -	$ 105,907,386
12							
13	**Operating Income Before Tax**	Ln.5 - Ln.11	$ 45,924,360	$ (5,216,878)	$ 40,707,483	$ 11,733,366	$ 52,440,849
14							
15	Income Tax Expense	Stmt K Ln.70	9,574,529	(1,704,553)	7,869,975	3,187,944	11,057,919
16							
17	**Return (Operating Income)**	Ln.13 - Ln.15	**$ 36,349,831**		**$ 32,837,508**		**$ 41,382,930**
18							
19	**Rate of Return**	Ln.17 ÷ Ln.27	**6.91%**		**5.60%**		**7.06%**
20							
21	**Rate Base**						
22	Plant in Service	Stmt D, Ln.19	$ 856,329,951	$ 72,642,269	$ 928,972,220	$ -	$ 928,972,220
23	Accumulated Depreciation	Stmt E, Ln.21	(285,893,862)	(3,135,089)	(289,028,951)	-	(289,028,951)
24	Working Capital	Stmt F Ln.7	4,210,255	(954,097)	3,256,158	-	3,256,158
25	Other Rate Base Items	Sched M-1 Ln.74	(48,778,735)	(8,260,213)	(57,038,949)	-	(57,038,949)
26							
27	**Total Rate Base**		**$ 525,867,609**	**$ 60,292,870**	**$ 586,160,478**	$ -	**$ 586,160,478**

BLACK HILLS NEBRASKA GAS, LLC
JURISDICTIONAL REVENUE REQUIREMENT
FOR THE TEST YEAR ENDING DECEMBER 31, 2020

Line No.	Description	Reference	(a) Base Year Per Books	(b) Pro Forma Adjustments	(c) (a) + (b) Adjusted Total	(d) Additional Revenue Required	(e) (c) + (d) Adjusted Rate of Return
1	**Operating Revenue**						
2	Total Sales - Jurisdictional	Stmt N Ln. 292	$ 175,116,722	$ (59,817,152)	$ 115,299,571	$ 17,295,841	$ 132,595,412
3	Total Sales - Non Jurisdictional		-	-	-	-	-
4	Other Operating Revenue	Stmt N Ln. 289	3,822,696	881,088	4,703,784	-	4,703,784
5	Total Operating Revenue		$ 178,939,419	$ (58,936,064)	$ 120,003,355	$ 17,295,841	$ 137,299,196
6							
7	**Operating Expenses**						
8	Operation and Maintenance	Stmt N Ln. 260	$ 58,831,274	$ 6,992,782	$ 65,824,056	$ -	$ 65,824,056
9	Depreciation	Stmt N Ln. 270	-	20,260,396	20,260,396	-	20,260,396
10	Taxes Other Than Income Tax	Stmt N Ln. 279	5,089,119	1,048,515	6,137,633	-	6,137,633
11	Total Operating Expenses		$ 63,920,392	$ 28,301,693	$ 92,222,086	$ -	$ 92,222,085
12							
13	**Operating Income Before Tax**	Ln.5- Ln.11	$ 115,019,027	$ (87,237,758)	$ 27,781,269	$ 17,295,841	$ 45,077,111
14							
15	Income Tax Expense	Stmt N Ln. 302	5,846,812	(1,040,908)	4,805,904	4,699,263	9,505,167
16							
17	**Return (Operating Income)**	Ln.13 - Ln.15	**$ 109,172,215**		**$ 22,975,365**		**$ 35,571,944**
18							
19	**Rate of Return**	Ln.17 ÷ Ln.27	**24.23%**		**4.56%**		**7.06%**
20							
21	**Rate Base**						
22	Plant in Service	Stmt N Ln. 61	$ 737,967,774	$ 62,367,854	$ 800,335,628	$ -	$ 800,335,628
23	Accumulated Depreciation	Stmt N Ln. 72	(246,253,636)	(1,567,271)	(247,820,907)	-	(247,820,907)
24	Working Capital	Stmt N Ln. 82	3,796,547	(822,250)	2,974,297	-	2,974,297
25	Other Rate Base Items	Stmt N Ln. 89	(44,952,955)	(6,684,174)	(51,637,129)	-	(51,637,129)
26							
27	**Total Rate Base**		**$ 450,557,729**	**$ 53,294,160**	**$ 503,851,889**	$ -	**$ 503,851,889**

Diagram and description of corporate structure, affiliates, and shared resource affiliates

- Attached is description and organization chart of Black Hills Corporation ("BHC") and its various subsidiaries
- Black Hills Nebraska Gas is a third tier corporate entity of BHC
- Shared Resource Affiliates are Black Hills Service Company ("BHSC") and Black Hills Utility Holdings ("BHUH")
- *See also*, Cost Allocation Manuals (CAM) attached to *Application Exhibit 1, Section 3, Exhibit F* for further description of allocation methodologies for services provided by BHC Shared Resources Affiliates and testimony of Mr. Clevinger.

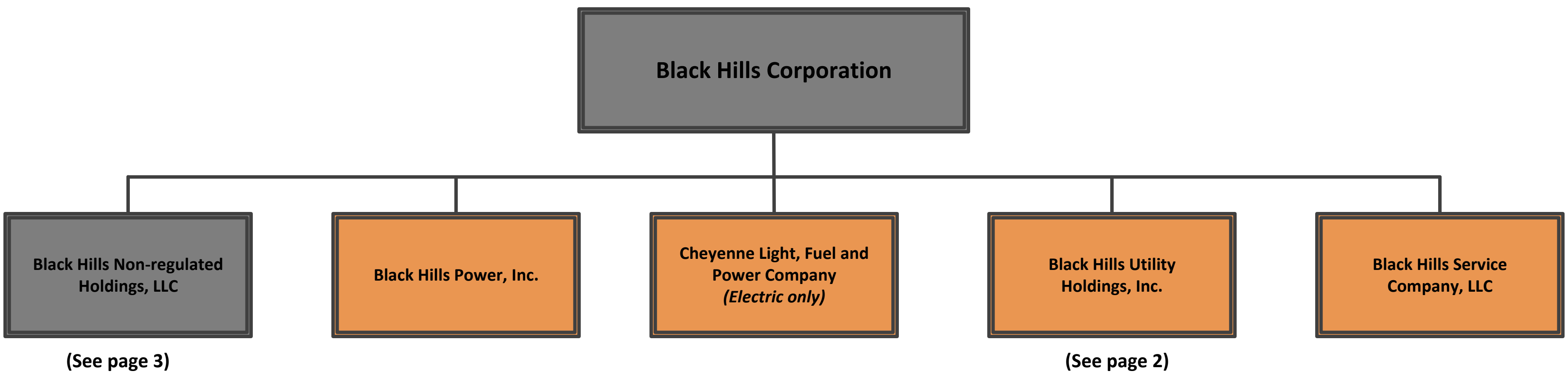
Black Hills Corporation and Subsidiaries

Company Name	Description of Business Nature and Purpose
Black Hills Colorado Electric, LLC (BHCE)	BHCE is a regulated public utility engaged in the generation, transmission, distribution and sale of electricity to approximately 85,869 customers in Colorado.
Black Hills Colorado Gas, Inc. (BHCG)	BHCG is a public utility engaged in the distribution and sale of natural gas to approximately 176,485 customers in Colorado.
Black Hills Colorado IPP, LLC (BHCOIPP)	BHCOIPP is an Exempt Wholesale Generator. It owns the Pueblo Airport Generating Station (PAGS), which provides capacity and energy to BHCE. In April 2016, BHEG sold a 49.9%, non-controlling interest in BHCOIPP to AIA Energy North America LLC. BHCOIPP continues to operate the facility.
Black Hills Colorado Wind, LLC (BHCW)	BHCW is an Exempt Wholesale Generator. It owns the Busch Ranch II windfarm which provides capacity and energy capacity to BHCE.
Black Hills Corporation (BHC)	BHC is a diversified energy company headquartered in Rapid City, South Dakota.
Black Hills Electric Generation, LLC (BHEG)	BHEG is an Exempt Wholesale Generator and an intermediate holding company for subsidiaries engaged in the generation and sale of electricity.
Black Hills Energy Arkansas, Inc. (BHEA)	BHEA, f/k/a SourceGas Arkansas Inc., is a regulated public utility engaged in retail natural gas distribution operations that serve approximately 174,400 customers in Arkansas.
Black Hills Energy Services Company (BHES)	BHES, f/k/a SourceGas Energy Services Company, is an unregulated natural gas marketer providing primarily retail distribution to customers in Nebraska and Wyoming with unbundled natural gas commodity offerings under the regulatory-approved Choice Gas Program.
Black Hills Exploration and Production, Inc. (BHEP)	The assets of BHEP (formerly an oil and natural gas exploration, development and production company) were sold between 2017 and 2019.
Black Hills Gas, Inc. (BHG, Inc.)	BHG, Inc., f/k/a SourceGas, Inc., is an indirect subsidiary of BHGH and an intermediate holding company.

Company Name	Description of Business Nature and Purpose
Black Hills Gas, LLC (BHG, LLC)	BHG, LLC, f/k/a SourceGas LLC, is a direct subsidiary of BHGH and an intermediate holding company.
Black Hills Gas Holdings, LLC (BHGH)	BHGH, f/k/a SourceGas Holdings, LLC, is the holding company for the SourceGas entities purchased by BHUH in February 2016.
Black Hills Gas Parent Holdings II, Inc. (BHGP II)	BHGP II owns 50% of BHGH.
Black Hills Gas Resources, Inc. (BHGR)	BHGR, a subsidiary of BHEP, is inactive.
Black Hills/Iowa Gas Utility Company, LLC (BHIAG)	BHIAG is a regulated public utility engaged in the distribution and sale of natural gas to approximately 159,600 customers in Iowa.
Black Hills/Kansas Gas Utility Company, LLC, (BHKSG)	BHKSG is a regulated public utility engaged in the distribution and sale of natural gas to approximately 115,800 customers in Kansas.
Black Hills Nebraska Gas, LLC (BHNEG)	BHNEG, f/k/a Black Hills/Nebraska Gas Utility Company, LLC, is a regulated public utility engaged in the distribution and sale of natural gas to approximately 293,600 customers in Nebraska.
Black Hills Non-regulated Holdings, LLC (BHNH)	BHNH is a holding company for our non-regulated entities.
Black Hills Plateau Production, LLC (BHPP)	BHPP, a subsidiary of BHEP, is inactive.
Black Hills Power, Inc. (BHP)	BHP is a regulated public utility engaged in the generation, transmission, distribution and sale of electricity to approximately 70,500 customers in eleven counties in western South Dakota, eastern Wyoming, and southwestern Montana.
Black Hills Service Company, LLC (BHSC)	BHSC is a corporate services company providing accounting, financial, legal, payroll, etc. services for BHC and its subsidiaries.
Black Hills Shoshone Pipeline, LLC (BHSP)	BHSP is a FERC-regulated interstate pipeline.
Black Hills Utility Holdings, Inc. (BHUH)	BHUH, a utility holding company, owns our electric and gas utilities in Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming.
Black Hills Wyoming Gas, LLC (BHWG)	BHWG is a regulated public utility engaged in the distribution and sale of natural as to approximately 127,000 customers in Wyoming.
Black Hills Wyoming, LLC (BHWY)	BHWY is an Exempt Wholesale Generator. It owns 76.5% of the Wygen I power plant, a coal-fired electric generation facility located near Gillette, Wyoming, at the Wyodak coal mine.
Cheyenne Light, Fuel and Power Company (CLFP)	CLFP is a regulated public utility engaged in the generation, transmission, distribution and sale of electricity to approximately 44,000 customers in Wyoming.
Mallon Oil Company, Sucursal Costa Rica (MOC)	MOC, a subsidiary of BHEP, is dormant.
N780BH, LLC	N780BH, LLC is a subsidiary of BHNH providing aircraft services.
Northern Iowa Windpower LC	NIW was acquired in 2019 from AltaGas. It is an Exempt Wholesale Generator and owns and operates the Top of Iowa Windfarm.

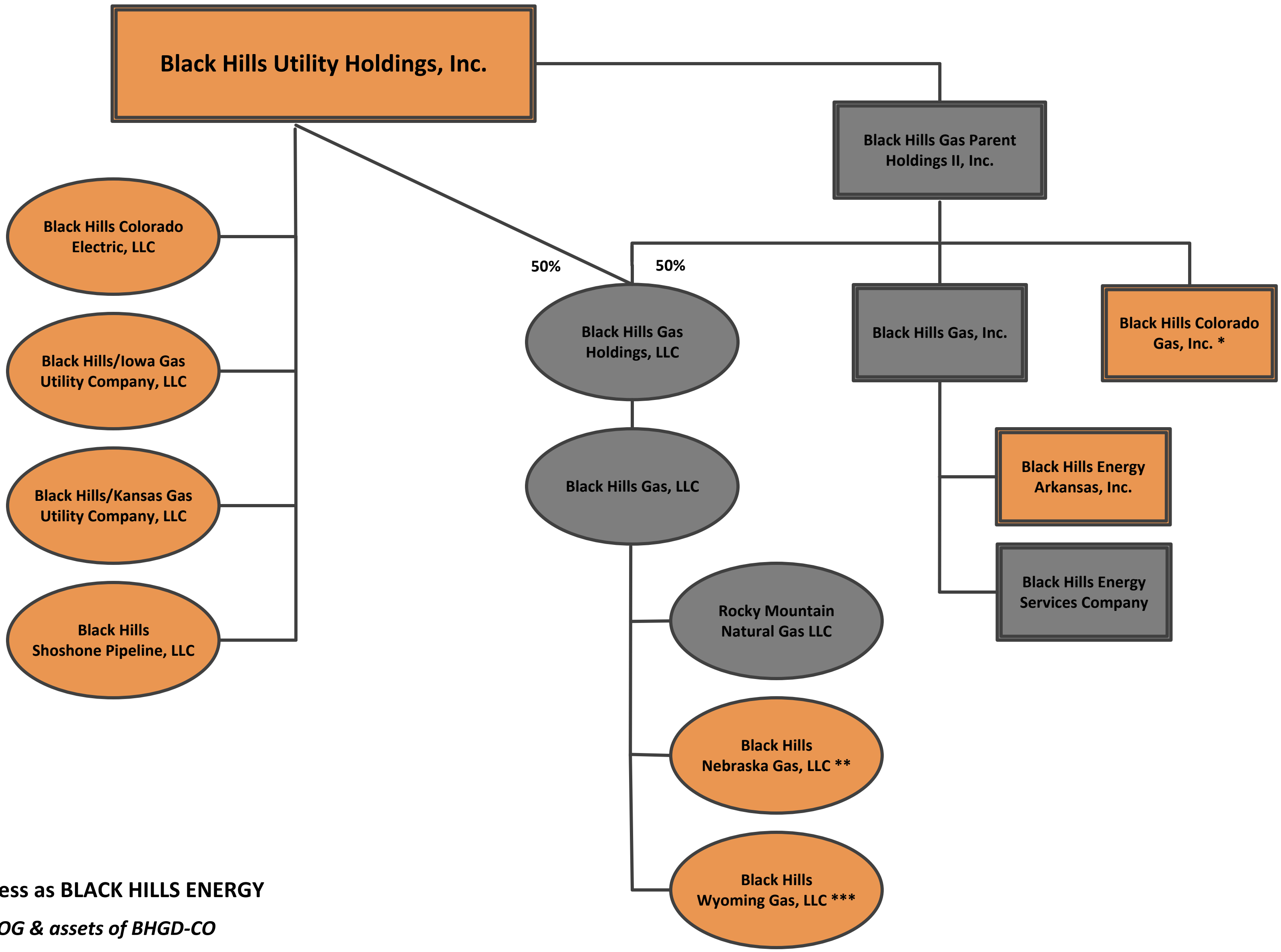
Company Name	Description of Business Nature and Purpose
Rocky Mountain Natural Gas LLC (RMNG)	RMNG was acquired with the SourceGas acquisition. It is a regulated public utility that provides regulated transmission to BHCG at town border stations in western Colorado. It also provides intrastate transportation services for natural gas producers, shippers and industrial customers.
Wyodak Resources Development Corp. (WRDC)	WRDC owns and operates a surface coal mine in the Powder River Basin, near Gillette, Wyoming. Substantially all of its coal production is sold under mid-term and long-term contracts.

DIAGRAM AND DESCRIPTION OF CORPORATE STRUCTURE, AFFILIATES, AND SHARED RESOURCE AFFILIATES



Doing business as BLACK HILLS ENERGY

DIAGRAM AND DESCRIPTION OF CORPORATE STRUCTURE, AFFILIATES, AND SHARED RESOURCE AFFILIATES



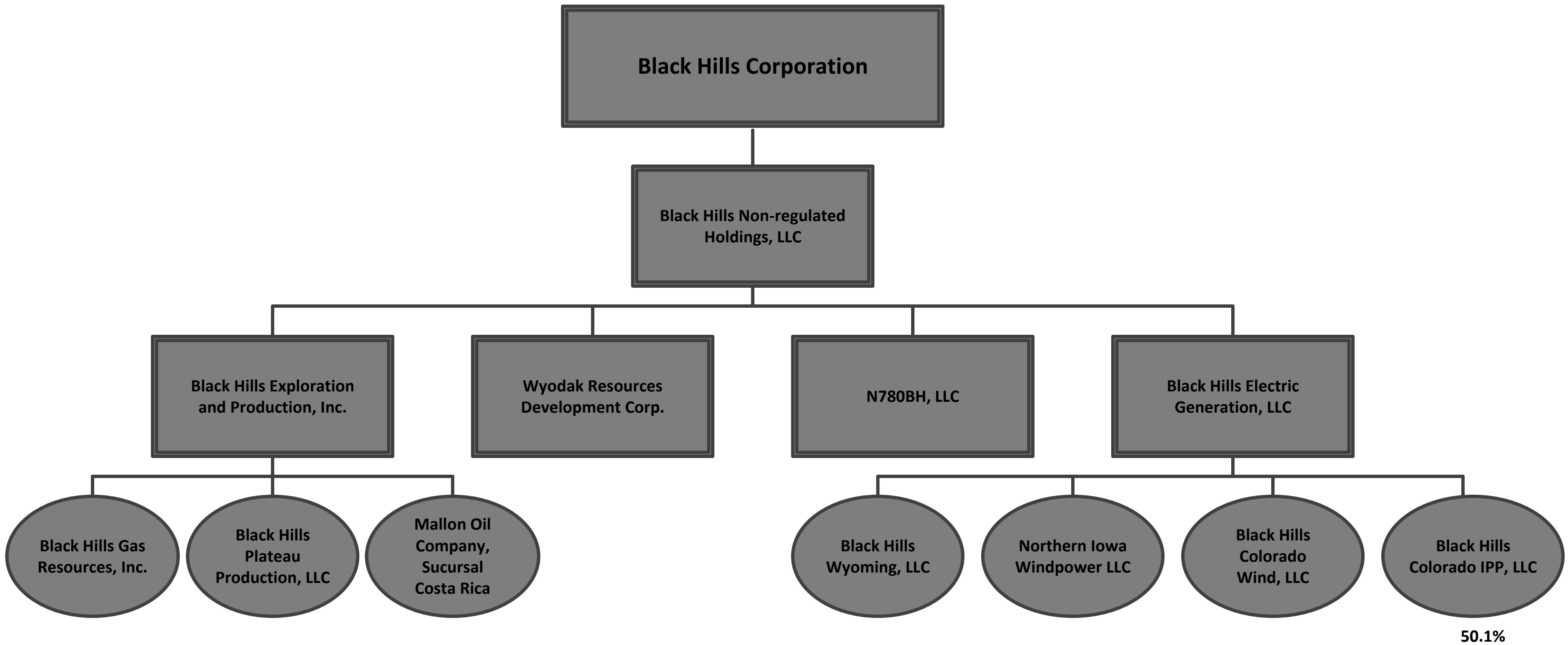
Doing business as BLACK HILLS ENERGY

* *Includes BHCOG & assets of BHGD-CO*

** *Includes BHNEG & assets of BHGD-NE*

*** *Includes BH Northwest Wyoming Gas, assets of CLFP gas & BHGD-WY*

DIAGRAM AND DESCRIPTION OF CORPORATE STRUCTURE, AFFILIATES, AND SHARED RESOURCE AFFILIATES



Financial Statements for the most current year.

The financial statement for the most recent fiscal year (i.e., 2019) for Black Hills Nebraska Gas, LLC are replicated from the Revenue Requirement Study (*Exhibit Nos. MCC-2), Statements A and B.*

241 Neb. Admin. Code. Ch. 9., *Rule 004.02E.*

BLACK HILLS NEBRASKA GAS, LLC | **Exhibit No. MCC-2**

ASSETS AND OTHER DEBITS | **Statement A**

FOR THE BASE YEAR ENDED DECEMBER 31, 2019 |

Line No.	Description	Notes	FERC Account		December 31, 2019
1	Utility Plant				
2	Gas Plant in Service		101	$	718,134,793
3	Gas Plant in Service - ARO		101		3,261
4	Gas Leased Assets		101		933,812
5	Completed Construction Not Classified		106		92,659,688
6	Construction Work in Progress		107		11,800,664
7	Gas Plant Acquisition Adjustment	(1)	114		42,487,092
8	Gas Stored Underground		117		-
9	Other-Utility Property		118		45,535,472
10					
11	Gross Utility Plant			$	911,554,782
12	Accum. Prov. For Depreciation		108		(271,000,955)
13	Accum. Prov. For Depreciation - RWIP		108		1,183,436
14	Accum. Prov. For Depreciation - ARO		108		(3,263)
15	Accum. Prov. For Gas Leased Assets		108		(808,284)
16	Accum. Prov. For Amortization		111		(29,245)
17	Accum. Prov. For Amort. Of Acq Adj		115		-
18	Res for Depr Other Utility Property		119		(14,863,661)
19	Total Utility Plant			$	626,032,809
20					
21	Non-Utility Property		101; 108; 121-122	$	540,433
22					
23					
24	Current and Accrued Assets				
25	Cash		131	$	-
26	Working Funds		135		-
27	Notes & Accts Receivable - Net		141-145; 173		70,482,287
28	Accts Rec Assoc Company		146		6,594,941
29	Fuel Stocks		151, 152		-
30	Material and Supplies		154-163		5,606,796
31	Gas Stored Underground		164		7,413,038
32	Prepayments		165		522,648
33	Other Current Assets		174, 176		2,894
34	Derv Instrument Assets		175		-
35	Total Current & Accrued Assets			$	90,622,604
36					
37	Deferred Debits				
38	Unamortized Debt Expense		181	$	-
39	Other Regulatory Assets		182		28,079,156
40	Preliminary Survey		183		107,633
41	Miscellaneous Debits		184-187		1,463,618
42	Deferred Income Tax		190		60,194,005
43	Unrecovered PGA		191		303,221
44	Total Deferred Debits			$	90,147,633
45					
46	Total Assets and Other Debits			$	807,343,479
47					
48	(Note 1): The 114 account contains the acquisition adjustment for Black Hills Nebraska Gas Utility.				
49	The goodwill associated with the acquisition of SourceGas has not at any time been allocated to BHGD-NE.				
50	It is entirely allocated to Black Hills Service Company ("BHSC") as is reflected on BHSC's books.				

BLACK HILLS NEBRASKA GAS, LLC | **Exhibit No. MCC-2**
LIABILITIES AND OTHER CREDITS | **Statement A**
FOR THE BASE YEAR ENDED DECEMBER 31, 2019 |

Line No.	Description	Notes	FERC Acct		December 31, 2019
1	Proprietary Capital				
2	Miscellaneous Paid in Capital		211	$	237,502,161
3	Unapprop. Retained Earnings		216	$	42,091,309
4	Accum. Other Comprehensive Income		219		-
5	Total Proprietary Capital			$	279,593,470
6					
7	Long Term Debt				
8	Intercompany Notes Payable	(2)	223	$	1,234,246
9	Unamort Discount on LTD		226	$	-
10	Operating Lease Obligation		227	$	62,085
11					
12	Other Non-Current Liabilities		228-230	$	16,971,004
13					
14	Current & Accrued Liability				
15	Accounts Payable		232	$	34,281,628
16	Notes Pay. Assoc Company		233		301,784,014
17	Acc Pay. Assoc Company		234		57,569,074
18	Customer Deposits		235		3,518,846
19	Taxes Accrued		236		4,394,339
20	Interest Accrued		237		-
21	Tax Collections Payable		241		3,972,746
22	Misc Current & Accrued Liab		242		12,120,663
23	Operating Lease Obligation - ST		243		64,726
24	Deriv Instrument Liab		244		-
25	Total Current & Accrued Liability			$	417,706,036
26					
27	Deferred Credits				
28	Customer Advance for Construction		252	$	-
29	Other Deferred Credits		253		5,390,841
30	Other Regulatory Liabilities		254		22,429,462
31	Acc Def ITC		255		-
32	Acc Def Inc Taxes - Property		282		53,045,323
33	Acc Def Inc Taxes - Other		283		10,911,013
34	Total Deferred Credits			$	91,776,639
35					
36					
37	Total Liabilities & Other Credits			$	807,343,479
38					

39 (Note 2): Includes $1,234,246 allocated from a corporate term loan due 2021, issued in accordance with a
40 PSC order related to the early termination and settlement of a gas supply contract (the Noble contract).
41 Proceeds from this term loan were used to finance the early termination of the gas supply contract,
42 resulting in a regulatory asset. This term loan is excluded from capital structures or cost of debt calculations.

BLACK HILLS NEBRASKA GAS, LLC **Exhibit No. MCC-2**
STATEMENT OF INCOME **Statement B**
FOR THE BASE YEAR ENDED DECEMBER 31, 2019

Line No.	Description	Reference		December 31, 2019
1	Gas Sales	480-482	$	145,980,108
2	Other Revenue	483-496		72,924,106
3	Sub-Total		$	218,904,213
4				
5				
6	Production & Gathering	750-770	$	-
7	Other Gas Supply	800-813		75,525,851
8	Underground Storage	814-836		-
9	Other Storage Expense	840-844		-
10	Transmission Expense	850-867		365,206
11	Distribution Expense	870-894		27,047,946
12	Customer Accounts Expense	901-905		7,364,060
13	Customer Service and Informational Expenses	907-910		255,757
14	Sales Expenses	911-916		561,524
15	Administrative & General Expense	920-932		31,946,971
16	Total O&M		$	143,067,313
17				
18	Depreciation & Amortization	403-405	$	24,036,687
19	Taxes Other than Income	408.1		5,875,853
20	Sub-Total		$	29,912,539
21				
22	Net Operating Income	Ln.3 - Ln.16 - Ln.20	$	45,924,361
23				
24	Non-Utility Operating Income (& Expense)	403, 408.2, 409.2, 415-426	$	3,969,388
25	Interest (Expense)	427-431		(19,320,606)
26	AFUDC - Debt & Equity	432		1,088,104
27	Non-Operating (Expense)	Ln. 24 + Ln. 25 + Ln. 26	$	(14,263,114)
28				
29	Income/(Loss) Before Tax	Ln.22 + Ln.27	$	31,661,247
30				
31	(Federal Income Taxes)/Benefit	409.1, 410-411	$	(2,997,982)
32				
33	Net Utility Income/(Loss)	Ln.29 + Ln.31	$	28,663,266

<u>Most Recent Annual Report To Stockholders</u>

See the 2019 Annual Report for Black Hills Corporation.

241 Neb. Admin. Code. Ch. 9., Rule 004.02F.

IN MOTION

2019 Annual Report | Proxy Statement | Form 10K

Black Hills Corporation

Ready

BKH

BLACK HILLS CORPORATION

We are a customer focused, growth-oriented utility company with a tradition of exemplary service and a vision to be the energy partner of choice. Based in Rapid City, South Dakota, the company serves 1.3 million electric and natural gas utility customers in 824 communities in Arkansas, Colorado, Iowa, Kansas, Montana, Nebraska, South Dakota and Wyoming. Employees partner to produce results that Improve Life with Energy.

Arkansas
174,400 utility customers
101 communities served

Colorado
289,800 utility customers
119 communities served
597 megawatts of owned power generation capacity

Iowa
159,600 utility customers
133 communities served
80 megawatts of owned power generation capacity

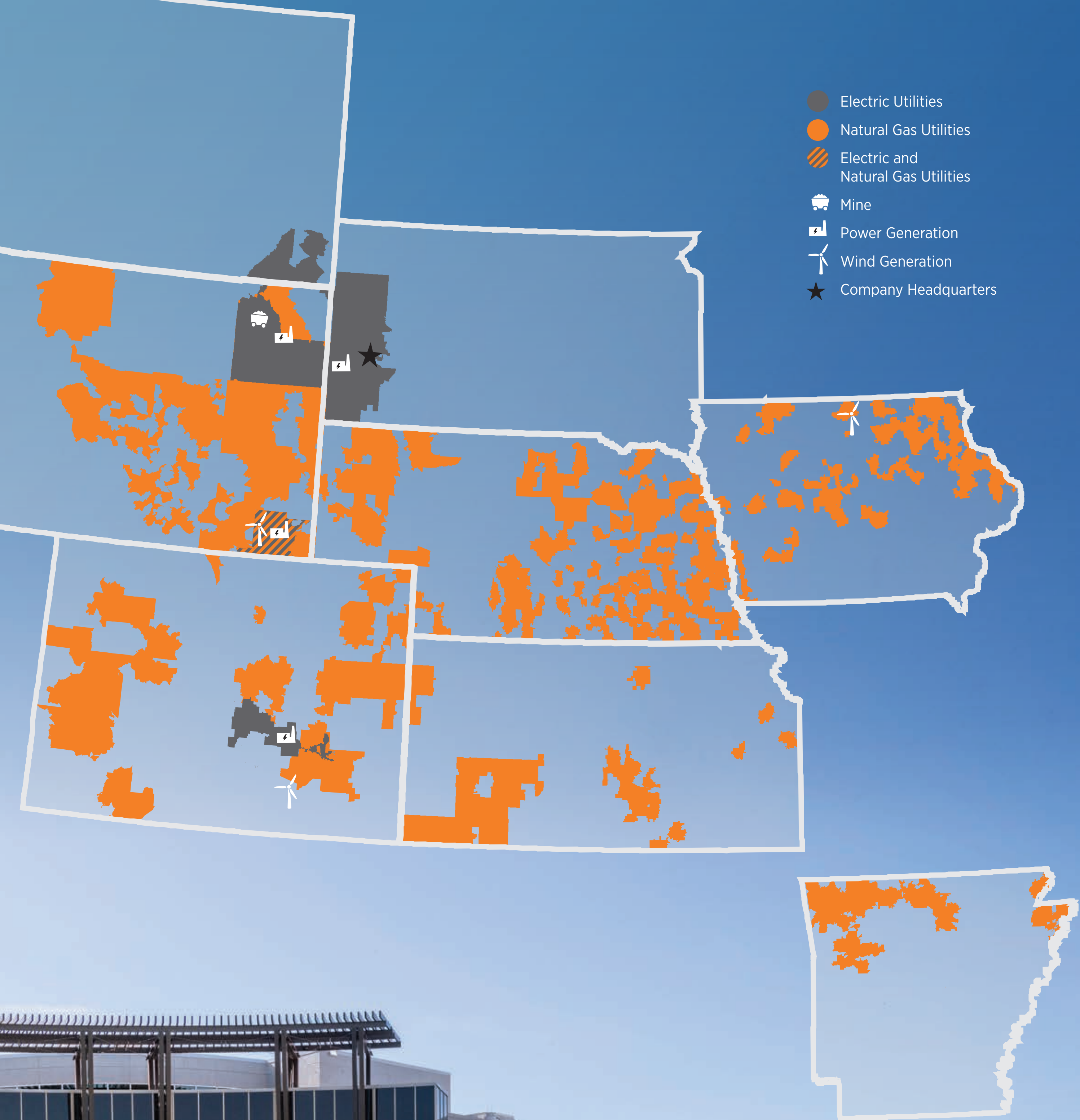
Kansas
115,800 utility customers
65 communities served

Montana
44 utility customers
2 communities served

Nebraska
293,600 utility customers
319 communities served

South Dakota
70,400 utility customers
29 communities served
130 megawatts of owned power generation capacity

Wyoming
176,900 utility customers
56 communities served
189 million tons of coal reserves
556 megawatts of owned power generation capacity


Electric Utilities
Natural Gas Utilities
Electric and
Natural Gas Utilities
Mine
Power Generation
Wind Generation
Company Headquarters

Linn Evans
President and Chief Executive Officer

DEAR FELLOW SHAREHOLDERS,

At Black Hills Corp., we endeavor every day to safely deliver essential energy to 1.3 million customers in eight states — across hundreds of miles — and in the small towns, rural communities and growing cities we call home. We are privileged to serve and have a proud history dating back to 1883, when electricity first began transforming our customers' lives and livelihoods. To this day, our customers remain at the center of all we do. We live alongside them, as part of their community and as part of their success.

The theme of this report, In Motion, reflects the dedication and drive our 2,900 employees bring to work every day to ensure our customers have the safe, reliable, and affordable electricity and natural gas they depend on to grow and thrive. In Motion reflects our commitment to delivering innovative and sustainable solutions to serve our customers' energy needs and meet their changing expectations. In Motion reflects how we're advancing our business strategy and delivering value to our customers, communities and shareholders.

David Emery
Executive Chairman of the Board

DELIVERING STRONG FINANCIAL RESULTS

2019 was a year of significant accomplishment for Black Hills Corp. Our engaged team delivered solid financial performance and positioned the company for sustainable, long-term growth. Financial results were strong with earnings, as adjusted, up 9% compared to the prior year. Adjusted earnings per share were $3.53* for the year — near the upper end of our guidance range for 2019. Our per share adjusted earnings were flat compared to 2018, off-setting dilution from the conversion of equity units in late 2018 and new shares issued in 2019.

Our stock price gained 25.1% in 2019 with a total shareholder return of 28.6%, outpacing the company's peers and utility indexes. Our stock reported multiple record high closing prices during the year, including an all-time high of $81.64. Our 5-year stock performance was also excellent, with the share price up 48.1% reflecting a total shareholder return of 72.7%.

Of special note, we increased your dividend by 6.2% in 2019 to $2.05 per share. Black Hills Corp. has paid dividends annually since 1942 and the increase in 2019 puts the company on track to achieve an important milestone in 2020 — 50 consecutive annual dividend increases, the second longest track record of any electric or gas utility in the country.

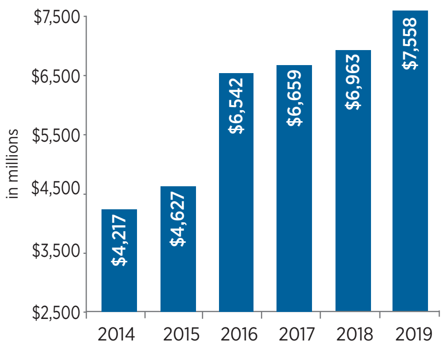
Our results continue to be driven by the successful execution of our customer-focused capital investment program and by achieving operating efficiencies and cost management through business standardization.

In 2019, we deployed $850 million in customer-focused capital to improve the safety and reliability of our extensive electric and natural gas systems, foster customer growth and expand our renewable energy offerings. Our service territory spans nearly 1,600 miles across 824 communities in eight geographically-diverse states. To serve our customers, we operate and maintain one of the largest natural gas and electric infrastructure systems in the country — composed of 46,000 miles of natural gas lines and 9,000 miles of electric transmission and distribution lines. We take a long-term, programmatic approach to maintaining and upgrading our systems and prioritizing the deployment of resources and capital to mitigate risk. Due to ongoing infrastructure needs, particularly within our gas utilities, we are forecasting capital investments of $2.7 billion in 2020 through 2024.

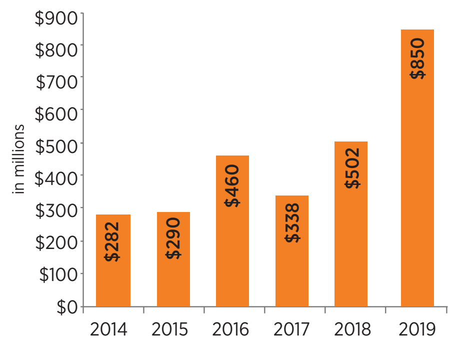
We are committed to delivering long-term value to you, our shareholders, through our customer-focused investment strategy, growing our dividend and improving our balance sheet. In 2019, we issued $100 million of new equity through our at-the-market equity offering program. We also issued $700 million of long-term debt, more closely aligning our debt maturities with our long-lived assets.

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

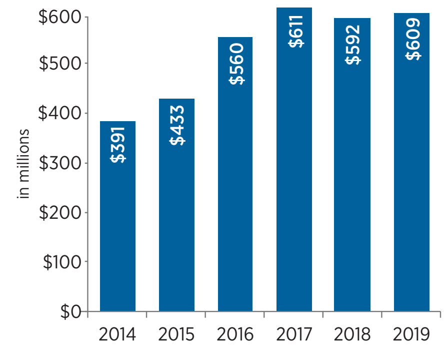
Total assets



Capital expenditures[1]

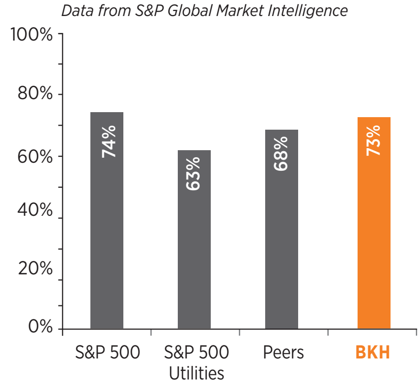


EBITDA, as adjusted[2]

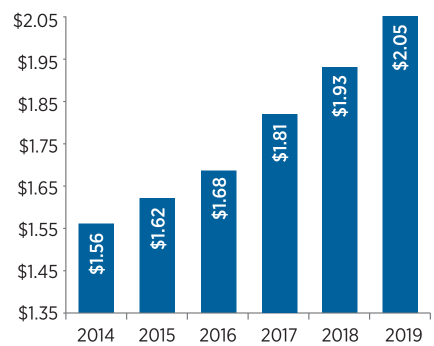


5-year total shareholder return

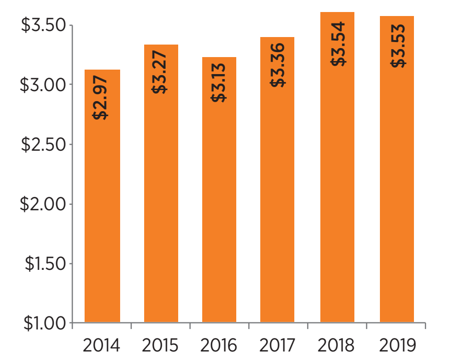
Data from S&P Global Market Intelligence



Dividend per share



Earnings per share, as adjusted[2,3]



(In millions except per share amounts)

STOCK INFORMATION (year-end)

	2019	2018	2017
Stock price per share	$78.54	$62.78	$60.11
Common shares outstanding	61.5	60.0	53.5
Market capitalization	$4,828	$3,767	$3,218

COMPANY KEY INDICATORS

	2019	2018	2017
Total capital expenditures[1]	$850	$502	$ 338
Total assets	$7,558	$6,963	$6,659
Total debt	$3,495	$3,142	$3,326
Net income available for common stock	$199	$258	$177

PER SHARE INFORMATION

	2019	2018	2017
Earnings per share: GAAP	$3.28	$4.66	$3.21
Earnings per share, as adjusted[2,3]	$3.53	$3.54	$3.36
Dividend per share	$2.05	$1.93	$1.81
Dividend yield at year-end	2.6%	3.1%	3.0%
Dividend growth	6.2%	6.6%	7.7%

1 From continuing operations; excludes capital for SourceGas purchase in 2016
2 Non-GAAP measure reconciled to GAAP starting on page A-1
3 From continuing operations

ENGAGING STAKEHOLDERS

In 2019, we continued to advance key regulatory initiatives to implement solutions to better and more efficiently serve our customers. We are making good progress in our plans to consolidate our multiple gas distribution utilities within Colorado, Nebraska and Wyoming.

COLORADO

In Colorado, we completed the legal consolidation of our two natural gas utilities into a single company called Black Hills Colorado Gas. We are working through two proposals pending with the Colorado Public Utilities Commission — the first, to streamline the rates, tariffs and services within our Colorado Gas territories — and the second, to update base rates to recover investments made in 2018 to ensure the safety and reliability of our natural gas system.

WYOMING

During 2019, we received approval from the Wyoming Public Service Commission to consolidate our four natural gas utilities into one new legal entity. In December, the commission approved a settlement agreement allowing the company to establish state-wide customer rates, consolidate general tariffs, and implement a general rate increase. This represented the final step in our process to reduce the complexity of our business in Wyoming, leading to improved customer service. New customer rates went into effect in the first quarter of 2020.

NEBRASKA

The Nebraska Public Services Commission approved the legal consolidation of our two natural gas utilities in mid-2019 with an effective date of Jan. 1, 2020. We plan to file a rate review in mid-2020 to consolidate the tariffs, rates and terms and conditions of the two gas utilities.

OTHER HIGHLIGHTS

Wygen I: Our team selected a resource solution to meet our Wyoming Electric affiliate's generation capacity shortfall of 60 megawatts (MW) starting in 2023. We have proposed a new, 20-year power purchase agreement with Wygen I, a mine-mouth generating facility owned by our power generation segment, Black Hills Wyoming. We submitted our application to the Federal Energy Regulatory Commission (FERC) in late 2019 seeking approval of this agreement. If approved, Wygen I would continue to provide our customers with safe and reliable energy, ensure the long-term price stability afforded by a low-cost Wyoming energy resource, and continue to provide stable, long-term mining and plant operations jobs within the state.

Federal Tax Cuts and Jobs Act: With the 2019 approval of our Wyoming tax implementation plan, we wrapped up the final requirement of the Federal Tax Cuts and Jobs Act of 2017, ensuring all our customer rates reflect the lower federal corporate income tax rate.

DELIVERING SUSTAINABLE ENERGY SOLUTIONS

Our Renewable Ready program is just one example of how we're delivering innovative and sustainable solutions to serve our customers' energy needs and changing expectations. Introduced in 2018 and approved by regulators in 2019, Renewable Ready provides our customers the opportunity to advance their business goals and sustainability objectives by choosing cost-effective, utility-scale renewable energy resources to power their businesses. Renewable Ready gives customers the option of subscribing to renewable energy resources for up to 100% of their electric energy needs. The program is available to large commercial and industrial customers and government agencies in South Dakota and Wyoming.

To support the Renewable Ready program, the company will build a new wind generating facility in 2020 — the Corriedale Wind Energy Project. Due to high customer demand, the wind project, originally proposed as a 40 MW facility, has been expanded to 52.5 MW. Renewable Ready subscribers will pay a cost-effective rate for the full cost of generating, integrating and delivering the renewable energy produced at the wind project. Corriedale, located near Cheyenne, Wyoming, will be jointly owned by the company's electric utility subsidiaries in South Dakota and Wyoming.

Following historic flooding in the Midwest, our team worked tirelessly to rebuild critical infrastructure and restore service to our customers.

DELIVERING VALUED SERVICE

In every aspect of our business, we remain focused on providing the highest level of service and value to our customers. We completed several key projects during the year to improve the safety and reliability of our natural gas and electric systems, integrate more renewable energy, and strengthen the grid. Projects of note included: our 35-mile Natural Bridge pipeline in Central Wyoming, our new, 60 MW Busch Ranch II wind project in Southern Colorado, and the completion of the final 94-mile segment of our 175-mile electric transmission line from Rapid City, South Dakota, to Stegall, Nebraska. We will share more details about these projects in the pages to follow.

Our commitment to our customers starts with our commitment to safety. From the safe and reliable operation of our power plants, electric grid and natural gas infrastructure, to the work we do each day in service to our customers, nothing is more important. We are very proud of our safety culture and we work hard at it, every day. We never lose sight of the critical nature of our work, especially in times of crisis, when our customers and communities need us most.

This was never more evident than in March 2019, when historic flooding in the Midwest left entire communities in our Nebraska and Iowa service territories under water. Major rivers and large tributaries flooded their banks, levees were breached, and the 90-year-old Spencer Dam failed in Nebraska, sending an 11-foot wave of water downstream toward the Missouri River. Hundreds of our customers were forced to evacuate with little warning as quickly rising waters washed out roadways, flooded homes and businesses, and left farms under as much as 8-feet of water.

The flooding also caused significant damage to our natural gas infrastructure, which called for a quick response from our teams to ensure the safety of our customers and communities. In Nebraska, our coworkers responded to emergency calls in 63 communities, requiring them to turn off gas at nearly 500 meters, as well as secure washed-out gas mains and make repairs at several town border stations. The flooding in Hamburg, Iowa, was so extensive our crews turned off the gas to the entire town in order to ensure the safety of this community.

With overnight temperatures nearing freezing at that time of year, our teams worked together to find safe solutions to get the gas flowing as quickly as possible after the floodwaters receded. What would normally take months, took days, as our coworkers worked tirelessly to rebuild critical infrastructure and restore service to our customers.

DELIVERING OPERATIONAL EXCELLENCE

Delivering operational excellence means we are always ready for our customers — ensuring they have the energy they need today and every day. Our dedicated team works with precision and skill to ensure the safe and reliable operating performance of our power generating plants, energy grid and natural gas infrastructure.

ENHANCING THE CUSTOMER EXPERIENCE

We leverage technology to better serve our customers and meet their changing expectations. With smart meter technology — Advanced Metering Infrastructure (AMI) — across each of our three electric utilities, we are providing customers with the information they need to track and monitor their energy usage so they can take more control over their bills. AMI technology also provides critical information to our operations and customer service teams for utility data analytics, system planning and grid modernization efforts so we can more quickly detect and respond to power outages. In 2019, we implemented a proactive outage communications system for our electric customers, providing information to help them stay safe during an outage as well as provide outage restoration updates. Customers can choose to receive information via text message, email or phone calls according to their preferences.

INTEGRATING MORE RENEWABLES

In partnership with our regional utility partners, our Colorado Electric utility announced plans in late 2019 to join the Western Energy Imbalance Market. This move will create value for our customers through lower energy costs, improved grid reliability and the integration of more renewables onto the system.

TOP RELIABILITY PERFORMANCE

In 2019, all three of our electric utilities achieved reliability performance in the top 25% among all electric utilities in the nation. This high standard of operating performance reflects our proactive system planning, our thoughtful investment approach, and our team's focus on customer service. We continue to deliver top reliability performance, an achievement made possible by the outstanding performance of our generating plants and power delivery systems. Reflective of growing customer demand and strong economic growth in our service territories, our electric utilities in Colorado and Wyoming set new, all-time summer peak loads in 2019, with Wyoming Electric setting a new, all-time winter peak load as well.

2019 PEAK SYSTEM DEMAND*

(in megawatts)

Colorado	Summer	**422******
	Winter	297
South Dakota	Summer	335
	Winter	320
Wyoming	Summer	**265******
	Winter	**247******

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

** New record for peak demand

ADVANCING RENEWABLE ENERGY IN COLORADO

BUSCH RANCH II

For over a decade, we have been modernizing our electric system and growing our renewable energy portfolio to build one of the newest and cleanest energy grids in Colorado, fueled by wind, solar and natural gas generation. With the completion of our 60 MW Busch Ranch II wind farm in 2019, our system will achieve 30% energy delivery from renewable sources, an important milestone in a multi-year effort to advance our region's renewable energy goals and comply with state law and regulatory requirements.

As a Colorado-built project, the benefits of Busch Ranch II extend well beyond the generation of renewable energy. Through a partnership with Vestas, all components of the wind farm's 27 turbines were manufactured at facilities across Colorado, including Vestas' Pueblo campus — the largest wind turbine tower factory in the world — helping to promote local economic development and cement Southern Colorado as a renewable energy leader.

The $71 million wind project was developed by our power generation segment, Black Hills Electric Generation, for our affiliate electric utility, Colorado Electric. The project is sited on 13,000 acres south of Pueblo, Colorado, in Huerfano and Las Animas Counties. All of the wind project's energy will be delivered to Colorado Electric through a 25-year power purchase agreement, providing an estimated $240 million in fuel savings to our customers over that period.

Busch Ranch II, Southern Colorado

A PATH TO A CLEAN ENERGY FUTURE

To further our renewable energy ambitions, we submitted a proposal to the Colorado Public Utilities Commission in 2019 seeking approval of a plan to potentially add up to 200 MW of new, low-cost renewable energy resources to our Southern Colorado system.

While our Colorado Electric utility has sufficient power resources to meet our customers' day-to-day electricity needs, the plan, "Renewable Advantage," proposes to deliver significant customer savings by supplementing existing power supplies with renewable energy resources. Through a competitive solicitation process, the company will evaluate proposals for utility-scale renewable energy projects to include wind, solar and battery storage. Independent evaluators will determine the most cost-effective resource to increase the renewable portfolio of the company. Subject to commission approval, the addition of up to 200 MW of new renewable energy resources could result in approximately 65% of our Colorado Electric customers' energy usage produced from carbon-free resources by 2023.

Due to the intermittent nature of renewable energy resources — the wind doesn't always blow and the sun doesn't always shine — it is necessary to have backstop generation to ensure continuous reliability for our customers. Our modern, natural gas-fired Pueblo Airport Generating Station provides the reliable and flexible generation necessary to support the integration of large amounts of renewable energy onto our system.

DELIVERING AN ADVANCED, MODERN GAS SYSTEM

We are committed to ensuring the safe and reliable delivery of natural gas to our customers' homes and businesses. To do so, we consistently invest in our extensive natural gas system, taking a programmatic approach to maintaining, upgrading and replacing critical infrastructure to better serve our customers and communities and mitigate risk.

We successfully delivered several key projects in 2019 to enhance the safety and reliability of our natural gas system while supporting customers' growing needs for energy.

NATURAL BRIDGE

In 2019, we constructed and placed into service a new, 35-mile natural gas transmission line to enhance the reliability and capacity of our system, thereby ensuring our ability to meet the growing needs of our 57,000 customers in Central Wyoming. The $54 million Natural Bridge pipeline project is comprised of 12-inch steel pipeline and two new regulating stations. This expanded system provides access to additional natural gas supplies and ensures our customers have enough energy to meet their current and future needs.

After construction, we restore the land to its natural state. We re-seed, mulch and monitor the right-of-way until vegetation is re-established, minimizing the long-term impact to the land along our pipelines.

Natural Bridge job site, Central Wyoming

Natural gas resiliency project, Lincoln, Nebraska

KANSAS ACCELERATED REPLACEMENT PROGRAM

We place the highest value on safety, which extends to the safety of our systems, customers and communities. That's why in 2019, we began work on the first phase of an accelerated pipeline replacement program in Kansas. Over the next seven years, we will update all bare steel mains, service and yard lines within the city limits of communities in our Kansas service area. In total, we will complete 148 individual projects, consisting of 30.5 miles of main and 3,150 service lines, and invest $19 million to increase our system's safety.

LINCOLN RESILIENCY PROJECT

We completed a multi-phased project in 2019 to improve the safety and reliability of our natural gas system in Lincoln, Nebraska. The project encompassed the replacement and upgrade of 16 miles of aging natural gas pipeline, a portion of which was originally installed in 1930. In addition, four town border stations were upgraded to improve system safety while also allowing for additional natural gas supplies to serve the system.

RENEWABLE NATURAL GAS

Our customers are increasingly looking to us for innovative solutions that support their sustainability objectives. In partnership with our customers and communities, we are developing projects to convert raw biogas, derived primarily from landfills and wastewater treatment facilities, into pipeline quality renewable natural gas (RNG). Through our network of natural gas pipelines, we offer the opportunity for RNG to be accepted into our transmission and distribution system and delivered to our customers through interconnection receipt points. Working with our customers and developers, we have placed into service over 1,800 Mcf (thousand cubic feet) per day of pipeline quality RNG – enough energy to fuel nearly 4,000 homes per year. Our projects include: Butler County Landfill Gas Project, near David City, Nebraska; Sarpy County Landfill Gas Project, located near Papillion, Nebraska; and the Water Resource Recovery Center in Dubuque, Iowa.

SNOWY RANGE

With rapidly increasing population and economic growth in Laramie, Wyoming, our existing natural gas pipeline was unable to meet the higher customer demand for energy. We expanded the system in 2019 with a new, 4.5 mile, 12-inch steel natural gas pipeline, called the Snowy Range Loop. This new pipeline ensures the safety and reliability of the Laramie system and allows for customer growth.

LIVING OUR VALUES

When we think of our many accomplishments in 2019, one of the things that stands out the most is our coworkers' commitment to safety. Over the past 12 years, we have reduced workplace injuries by more than 73%. In 2019, our Total Case Incident Rate (incidents per 200,000 hours worked) was 1.25, well below the utility industry average of 1.95. Our Preventable Motor Vehicle Incident Rate (vehicle accidents per 1 million miles driven), another indicator of our safety performance, was 2.48 in 2019, well below the industry average of 3.11.

We are extremely proud of our coworkers at our Pueblo Airport Generating Station in Southern Colorado, who achieved the highest designation for workplace safety in 2019, earning the Voluntary Protection Program (VPP) Star Status from the Occupational Safety and Health Administration (OSHA). Driven entirely by our employee team, the path to VPP status was a multi-year effort with rigorous requirements by OSHA.

It's often said there is something uniquely special about utility people and Black Hills Corp. people are the best in the business. They are the folks who do what it takes — often leaving the comfort of their homes and families in the middle of the night and in the worst of conditions — to respond to those in need. This commitment to our customers was on full display during the March flood response and the severe winter storms we experienced last year, but it's also evident in the everyday actions of our team as they serve our customers.

From the courteous service from our call center agents, to the respectful way our field teams work with our customers to provide solutions and service, this commitment runs deep. Our customers are our neighbors, friends and family. In 2019, our community support totaled over $5.5 million, including over $520,000 in employee giving to United Way agencies and affiliates across our service territory and nearly $1 million in support of local economic development initiatives.

As we close this letter, we would like to take a moment to welcome two new independent directors to the Black Hills Corp. board of directors, Kathleen S. McAllister and Tony A. Jensen. With their extensive leadership experience in finance and capital-intensive sectors, they add significant value to the board as we execute our strategy and continue to deliver value to our customers and shareholders.

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

Sincerely,

David R. Emery and Linn Evans


CAT

READY TO SERVE

Our employees and their families give generously of their time and talents to support our customers and keep our communities strong and vibrant.

BLACK HILLS CORPORATION

Notice of 2020
Annual Meeting of Shareholders
and Proxy Statement

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BLACK HILLS CORPORATION

NOTICE OF ANNUAL MEETING OF SHAREHOLDERS

WHEN:	**WHERE:**
Tuesday, April 28, 2020 9:30 a.m., local time	Horizon Point Company's Corporate Headquarters 7001 Mount Rushmore Road Rapid City, South Dakota 57702

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

Proposals:

1. Election of one director in Class I: Kathleen S. McAllister; three directors in Class II: Rebecca B. Roberts, Teresa A. Taylor, and John B. Vering; and one director in Class III: Tony A. Jensen.
2. Ratification of Deloitte & Touche LLP to serve as our independent registered public accounting firm for 2020.
3. Adoption of an advisory, non-binding resolution to approve our executive compensation.
4. Any other business that properly comes before the annual meeting.

Record Date:

The Board of Directors set March 2, 2020 as the record date for the meeting. This means that our shareholders as of the close of business on that date are entitled to receive this notice of the meeting and vote at the meeting and any adjournments or postponements of the meeting.

How to Vote:

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

Sincerely,

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

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BLACK HILLS CORPORATION

7001 Mount Rushmore Road
Rapid City, South Dakota 57702

PROXY STATEMENT

✓ A proxy in the accompanying form is solicited by the Board of Directors of Black Hills Corporation, a South Dakota corporation, to be voted at the annual meeting of our shareholders to be held Tuesday, April 28, 2020, and at any adjournment of the annual meeting.

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

✓ We will bear all costs of the solicitation. In addition to solicitation by mail, our officers and employees may solicit proxies by telephone, fax, or in person. We have retained Georgeson LLC to assist us in the solicitation of proxies at an anticipated cost of $8,500, plus out-of-pocket expenses. Also, we will, upon request, reimburse brokers or other persons holding stock in their names or in the names of their nominees for reasonable expenses in forwarding proxies and proxy materials to the beneficial owners of stock.

✓ This proxy statement and the accompanying form of proxy are to be first mailed on or about March 13, 2020. Our 2019 annual report to shareholders is being mailed to shareholders with this proxy statement.

VOTING RIGHTS AND PRINCIPAL HOLDERS

✓ Only our shareholders of record at the close of business on March 2, 2020 are entitled to vote at the meeting. Our outstanding voting stock as of the record date consisted of 62,750,615 shares of our common stock.

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

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TABLE OF CONTENTS

PROXY STATEMENT

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COMMONLY ASKED QUESTIONS AND ANSWERS ABOUT THE ANNUAL MEETING PROCESS

Who is soliciting my proxy?

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

Where and when is the annual meeting?

The annual meeting is at 9:30 a.m., local time, April 28, 2020 at Horizon Point, the Company's corporate headquarters, 7001 Mount Rushmore Road, Rapid City, South Dakota.

Who can vote?

Holders of our common stock as of the close of business on the record date, March 2, 2020, can vote at our annual meeting. Each share of our common stock has one vote for Proposals 2 and 3. Related to Proposal 1, Election of Directors, cumulative voting is permitted in the election of directors in the same class.

How do I vote?

There are three ways to vote by proxy:

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

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

What constitutes a quorum?

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

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

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

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

Is cumulative voting permitted for the election of directors?

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

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

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

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

What should I do now?

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

Who will count the vote?

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

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

We are asking for your proxy for the annual meeting and will pay all the costs of asking for shareholder proxies. We have hired Georgeson LLC to help us send out the proxy materials and ask for proxies. Georgeson LLC's fee for these services is anticipated to be $8,500 plus out-of-pocket expenses. We can ask for proxies through the mail or by telephone, fax, or in person. We can use our directors, officers and employees to ask for proxies. These people do not receive additional compensation for these services. We will reimburse brokers and other custodians, nominees and fiduciaries for their reasonable out-of-pocket expenses for forwarding solicitation material to the beneficial owners of our common stock.

Can I revoke my proxy?

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

Who should I call with questions?

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

When are the shareholder proposals due for the 2021 annual meeting?

In order to be considered for inclusion in our proxy materials, you must submit proposals for next year's annual meeting in writing to our Corporate Secretary at our corporate headquarters at 7001 Mount Rushmore Road, P.O. Box 1400, Rapid City, South Dakota 57709, on or prior to November 13, 2020.

A shareholder who intends to submit a proposal for consideration, but not for inclusion in our proxy materials, must provide written notice to our Corporate Secretary in accordance with Article I, Section 9 of our Bylaws. In general, our Bylaws provide that the written notice must be delivered not less than 90 days nor more than 120 days prior to the first anniversary date of the immediately preceding annual meeting of shareholders. Our 2020 annual meeting is scheduled for April 28, 2020. Ninety days prior to the first anniversary of this date will be January 28, 2021, and 120 days prior to the first anniversary of this date will be December 29, 2020.

PROPOSAL 1 ELECTION OF DIRECTORS

Our Board is nominating five individuals for election as directors at this annual meeting. All of the nominees are currently serving as our directors. In accordance with our Bylaws and Article VI of our Articles of Incorporation, members of our Board of Directors are elected to three classes of staggered terms consisting of three years each, and until their successors are duly elected and qualified. At this annual meeting, one director will be elected to Class I for a term of two years until our annual meeting in 2022, three directors will be elected to Class II for a term of three years until our annual meeting in 2023, and one director will be elected to Class III to complete the remainder of the term expiring at our annual meeting in 2021.

Nominees for director at the annual meeting are Tony A. Jensen, Kathleen S. McAllister, Rebecca B. Roberts, Teresa A. Taylor and John B. Vering. Our Bylaws require a minimum of nine directors. The Board has set the size of the Board at 10 directors effective at the annual meeting in connection with two director retirements occurring at that time.

Pursuant to our Bylaws, directors must resign from the Board at the annual meeting following attaining 72 years of age. Accordingly, Mr. Zeller, who turned 72 in 2020, will resign effective at our annual meeting. We expect Mr. Madison, who will turn 72 prior to our 2021 annual meeting, will resign effective at that annual meeting and therefore serve his three-year term. Additionally, we expect Mr. Vering, who will turn 72 prior to our 2022 annual meeting, will resign effective at that annual meeting and therefore serve only two years of his term. As previously announced, Mr. Emery is not standing for re-election and plans to retire as an officer and employee of the company effective May 1, 2020.

If, at the time of the annual meeting, any of such nominees are unable to stand for election, the Board of Directors may designate a substitute or reduce the number of directors to nine. In that case, shares represented by proxies may be voted for a substitute director nominated by the Board. We do not expect that any nominee will be unavailable or unable to serve.

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

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

Director Nominee	Class	Year Term Expiring
Tony A. Jensen	III	2021
Kathleen S. McAllister	I	2022
Rebecca B. Roberts	II	2023
Teresa A. Taylor	II	2023
John B. Vering	II	2023

DIRECTOR BIOGRAPHIES

Average Tenure	Average Age	Diversity
5 Years	62	30% Women

Linden R. Evans	President and Chief Executive Officer of the Company since January 1, 2019, President and Chief Operating Officer from 2016 through 2018, and President and Chief Operating Officer - Utilities from 2004 through 2015.
Director since November 2018 **Director** Class III Term Expiring 2021 **Age** 57 **Board Committees** None **Other Public Company Boards** None	**<u>Specific Qualifications, Attributes, Skills and Experience:</u>** **Broad Range of Experience** Broad range of experience in his career in areas of utility management, strategic planning and execution, telecommunications, corporate legal and environmental matters. **Relevant Senior Leadership Experience** Currently President and Chief Executive Officer of the Company. Previously served as President and Chief Operating Officer from 2016 through 2018 and in various other leadership roles with the Company. **Extensive Knowledge of the Company's Business and/or Industry** 18 years of experience with the Company. Prior to joining the Company, he was a mining engineer and an attorney specializing in environmental and corporate legal matters. Serves on many industry association boards and advisory committees for large publicly traded mining companies.

Tony A. Jensen	Retired. Former President and Chief Executive Officer and Director of Royal Gold, Inc., a public precious metals company, from 2006 to 2019.
Director since 2019 **Director** Class III Term Expiring 2021 **Age** 58 **Board Committees** None **Other Public Company Boards** None	**<u>Specific Qualifications, Attributes, Skills and Experience:</u>** **High Level of Financial Expertise** Oversaw financial matters in his role as Chief Executive Officer and Director of a public company. **Relevant Senior Leadership Experience** Served as Chief Executive Officer and Director of Royal Gold, Inc. from 2006 to 2019 and President and Chief Operating Officer from 2003 to 2006. He also served as a director of several industry and public boards. **Extensive Knowledge of the Company's Business and/or Industry** Over 35 years of experience in the mining and mining finance industries where he held progressively more responsible roles in engineering, finance, strategic growth, safety, environmental excellence, and operational efficiency.

Michael H. Madison	Retired. Former President and Chief Executive Officer and Director of Cleco Corporation, a public utility holding company, from 2005 to 2011.
Director since 2012 **Director** Class III Term Expiring 2021 **Age** 71 **Board Committees** Compensation (Chair) Governance **Other Public Company Boards** None	**<u>Specific Qualifications, Attributes, Skills and Experience:</u>** **High Level of Financial Expertise** Oversaw financial matters in his role as Chief Executive Officer and Director of a public company. Previously served on our Audit Committee. **Relevant Senior Leadership Experience** Served as Chief Executive Officer and Director of Cleco Corporation from 2005 to 2011, and President and Chief Operating Officer of Cleco Power, LLC from 2003 to 2005. He was State President, Louisiana-Arkansas with American Electric Power from 2000 to 2003. **Extensive Knowledge of the Company's Business and/or Industry** More than 40 years of utility industry experience in various positions of increasing responsibility, including president, director, vice president of operations, engineering and production and vice president of corporate services. Served on many industry association boards and advisory committees.

Kathleen S. McAllister	Retired. Former President and Chief Executive Officer and Director of Transocean Partners LLC, a growth-oriented public company and subsidiary of Transocean Ltd., an international provider of offshore contract drilling services for oil and gas wells, from 2014 to 2016, and Chief Financial Officer in 2016.
Director since 2019 **Director** Class I Term Expiring 2022 **Age** 55 **Board Committees** None **Other Public Company Boards** Hoegh LNG Partners LP (since 2017) Maersk Drilling (since 2019) **Gender Diversity**	**<u>Specific Qualifications, Attributes, Skills and Experience:</u>** **High Level of Financial Expertise** Oversaw financial matters in her roles as Chief Executive Officer and Chief Financial Officer of a public company. **Relevant Senior Leadership Experience** Served as Chief Executive Officer and Director of Transocean Partners LLC, from 2014 to 2016, and Chief Financial Officer in 2016. Served as Vice President and Treasurer of Transocean Ltd. from 2011 to 2014. She has also served on several corporate and non-profit boards in addition to the boards identified at the left. **Extensive Knowledge of the Company's Business and/or Industry** Over 30 years of experience with diverse leadership roles in global, capital intensive companies in the energy value chain, including various roles of increasing responsibility in information technology, tax, treasury, and finance functions.

Steven R. Mills	Consultant and Advisor to Naxos Capital Partners, a European-based private equity company. Served as Chief Financial Officer of Amyris, Inc., a renewable products company, from 2012 to 2013. Also served as Senior Executive Vice President Performance and Growth of Archer Daniels Midland Company, one of the world's largest agricultural processors and food ingredient providers, from 2010 to 2012.
Director since 2011 **Director** Class III Term Expiring 2021 **Age** 64 **Board Committees** Lead Director Audit Governance **Other Public Company Boards** Amyris, Inc. (since 2018)	**<u>Specific Qualifications, Attributes, Skills and Experience:</u>** **High Level of Financial Expertise** Oversaw financial matters in his role as Chief Financial Officer at public companies. Has served on our Audit Committee for 9 years, including 4 previous years as Audit Chair. **Relevant Senior Leadership Experience** Serves as our Lead Director since April 2019. Served in several leadership positions with public companies including, Chief Financial Officer, Controller, Senior Executive Vice President Performance and Growth and Senior Vice President Strategic Planning. He has also served as a director and board committee chair of several public and privately-owned companies, in addition to Amyris, Inc., providing governance and oversight experience. **Risk Oversight/Management Expertise** More than 40 years of experience in the fields of accounting, corporate finance, strategic planning, risk management, and mergers and acquisitions. Significant risk oversight/management experience throughout his career in various executive leadership and finance positions.

Robert P. Otto	Owner of Bob Otto Consulting LLC, providing strategic planning and services in cyber security, intelligence, and reconnaissance since 2017. He retired from the U.S. Air Force in 2016 as a lieutenant general. He served as a general officer since 2008, culminating as the Air Force Deputy Chief of Staff for Intelligence, Surveillance and Reconnaissance.
Director since 2017 **Director** Class I Term Expiring 2022 **Age** 60 **Board Committees** Audit **Other Public Company Boards** None	**<u>Specific Qualifications, Attributes, Skills and Experience:</u>** **Financially Literate** Vast experience in areas spanning cyber security, strategic planning, and financial management from his military career. Serves on our Audit Committee. **Relevant Senior Leadership Experience** Commanded some of the Air Force's largest organizations with thousands of employees and billion-dollar budgets. Intelligence and cyber security expert with a proven record of success executing cost-effective, cutting-edge initiatives. Extensive background in operations, financial management, policy development, restructuring, and systems implementation. **Risk Oversight/Management Expertise** Significant risk oversight/management experience throughout his military career. As the Air Force's senior-most intelligence officer, he was directly responsible for policy planning, evaluation, oversight and leadership of a workforce of 27,000.

Rebecca B. Roberts	Retired. Former President of Chevron Pipe Line Company, a pipeline company transporting crude oil, refined petroleum products, liquefied petroleum gas, natural gas and chemicals within the United States, from 2006 to 2011. President of Chevron Global Power Generation from 2003 to 2006.
Director since 2011 **Director Nominee** Class II Term Expiring 2023 **Age** 67 **Board Committees** Compensation Governance (Chair) **Other Public Company Boards** AbbVie, Inc. (since 2018) MSA Safety, Inc. (since 2013) **Gender Diversity**	**Specific Qualifications, Attributes, Skills and Experience:** **Financially Literate** Operational and financial experience as a president of large public company subsidiaries and serving on public company boards. **Relevant Senior Leadership Experience** Served as President of Chevron Pipe Line Company from 2006 to 2011, and President of Chevron Global Power Generation from 2003 to 2006. She has also served on several public company and non-profit boards in addition to the ones identified at the left, including the board of Enbridge, Inc., from 2015 through May 2018. **Extensive Knowledge of the Company's Business and/or Industry** Over 35 years of experience in the energy industry, including managing pipelines in North America and global pipeline projects, and managing a portfolio of power plants in the United States, Asia and the Middle East. She also worked as a vice president, chemist, scientist and trader in the oil and gas sectors.

Mark A. Schober	Retired. Former Senior Vice President and Chief Financial Officer of ALLETE, Inc., a public utility company, from 2006 to 2014.
Director since 2015 **Director** Class I Term Expiring 2022 **Age** 64 **Board Committees** Audit (Chair) **Other Public Company Boards** None	**Specific Qualifications, Attributes, Skills and Experience:** **High Level of Financial Expertise** Oversaw financial matters in his role as Chief Financial Officer of a public utility company. More than 35 years of experience in the fields of finance and accounting. Serves on our Audit Committee, and as Chair since April of 2019. **Relevant Senior Leadership Experience** Served as Chief Financial Officer of ALLETE, Inc., a public utility company, from 2006 to 2014. **Extensive Knowledge of the Company's Business and/or Industry** More than 35 years of experience in the utility and energy industry, including an understanding of the regulated business model and unique challenges of the geographic and regulatory environment in which we operate.

Teresa A. Taylor	Chief Executive Officer of Blue Valley Advisors, LLC, an advisory firm, since 2011. Former Chief Operating Officer of Qwest Communications, Inc., a telecommunications carrier, from 2009 to 2011.
Director since 2016 **Director Nominee** Class II Term Expiring 2023 **Age** 56 **Board Committees** Compensation **Other Public Company Boards** T-Mobile USA, Inc. (since 2013) **Gender Diversity**	**Specific Qualifications, Attributes, Skills and Experience:** **Broad Range of Experience** Gained a broad range of experience in her career in areas of strategic planning and execution, technology development, human resources, labor relations and corporate communications. **Relevant Senior Leadership Experience** Served as Chief Operating Officer of Qwest Communications, Inc. where she led the daily operations and a senior management team responsible for 30,000 employees in field support, technical development, sales, marketing, customer support and IT systems. She has also served on several public company and non-profit boards in addition to the ones identified at the left. **Extensive Knowledge of the Company's Business and/or Industry** Over 30 years of experience in technology, media and the telecom sector. Served on the Board of NiSource, a public utility company, from 2012 to 2015, Columbia Pipeline Group, Inc. from 2015 to July 2016, and First Interstate BancSystem, Inc. from 2012 to 2020.

John B. Vering	Retired. Former Managing Director of Lone Mountain Investments, Inc., oil and gas investments, from 2002 to 2019. Partner in Vering Feed Yards LLC, a privately owned agricultural company, since 2010.
Director since 2005 **Director Nominee** Class II Term Expiring 2023 **Age** 70 **Board Committees** Audit Governance **Other Public Company Boards** None	**Specific Qualifications, Attributes, Skills and Experience:** **High Level of Financial Expertise** Has gained a high level of financial expertise as Managing Director of an entity making oil and gas investments. Has served on our Audit Committee for 9 years.
	Relevant Senior Leadership Experience Served as our Lead Director from March 2016 through April 2, 2019. Had a 23-year career with Union Pacific Resources Company in several positions of increasing responsibilities, including Vice President of Canadian Operations.
	Extensive Knowledge of the Company's Business and/or Industry Over 30 years of experience in the oil and gas industry, including direct operating experience in oil and gas transportation, marketing, exploration and production, and an understanding of the trans-national oil and gas business. He has served on our Board for 15 years.

Corporate Governance Guidelines

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

Board Independence

In accordance with NYSE rules, the Board of Directors through its Governance Committee, affirmatively determines the independence of each director and director nominee in accordance with guidelines it has adopted, which include all elements of independence set forth in the NYSE listing standards. These guidelines are contained in our Policy for Director Independence, which can be found in the “Governance” section of our website (www.blackhillscorp.com/investor-relations/corporate-governance). Based on these standards, the Governance Committee determined that each of the following non-employee directors is independent and has no relationship with us, except as a director and shareholder:

Tony A. Jensen	83% INDEPENDENT	Rebecca B. Roberts
Michael H. Madison		Mark A. Schober
Kathleen S. McAllister		Teresa A. Taylor
Steven R. Mills		John B. Vering
Robert P. Otto		Thomas J. Zeller

In addition, based on such standards, the Governance Committee determined that Messers. Emery and Evans are not independent because they are Officers of the Company.

Board Leadership Structure

As part of a planned leadership transition, Mr. Emery, after 14 years as Chairman and CEO, was appointed Executive Chairman of the Board of Directors, effective January 1, 2019. Mr. Evans, who had been President and Chief Operating Officer since 2016, was named President and CEO effective January 1, 2019.

Our Board has and continues to value a high degree of Board independence. As a result, our corporate governance structure and practices promote a strong, independent Board and include several independent oversight mechanisms. Only independent directors serve on our Audit, Compensation and Governance Committees. Our Board believes these practices ensure that experienced and independent directors will continue to effectively oversee management and critical issues related to financial and operating plans, long-range strategic issues, enterprise risk and corporate integrity. All of our Board committees may seek legal, financial or other expert advice from a source independent of management.

As provided in our Corporate Governance Guidelines of the Board of Directors, because our Executive Chairman is not independent, our Board annually appoints an independent Lead Director, and has done so since 2001. Steven R. Mills is our current Lead Director and has served in this role since May 2019. As provided in the Corporate Governance Guidelines, the primary responsibilities of the Lead Director are to chair executive sessions of the independent directors, and in conjunction with the Executive Chairman, communicate the Board’s annual evaluation of the CEO. The Lead Director, together with the independent directors, establishes the agenda for executive sessions, which are held at each regular Board meeting. The Lead Director serves as a liaison between the independent members of the Board, the Executive Chairman, and the CEO, and discusses, to the extent appropriate, matters raised by the independent directors in executive session. The Lead Director also consults with the Executive Chairman, and the CEO, as appropriate, regarding meeting agendas and presides over regular meetings of the Board in the absence of the Executive Chairman. This leadership structure provides consistent and effective oversight of our management and our Company.

The Board Role in Risk Oversight

Our Board oversees an enterprise approach to risk management that supports our operational and strategic objectives. The Corporate Governance Guidelines of the Board of Directors provide that the Board will review major risks facing our Company and the options for risk mitigation presented by management. Our Board delegates oversight of certain risk considerations to its committees within each of their respective areas of responsibility; however, the full Board monitors risk relating to strategic planning and execution, as well as executive succession. Financial risk oversight falls within the purview of our Audit Committee. Our Compensation Committee oversees compensation and benefit plan risks. Each committee reports to the full Board.

Our Board reviews any material changes in our key enterprise risk management ("ERM") issues, including cyber security, with management at each quarterly Board meeting. In addition, the Board reviews a deep dive enterprise risk topic with our Chief Risk Officer at most quarterly meetings. In so doing, our Board seeks to ensure appropriate risk mitigation strategies are implemented by management on an ongoing basis. Operational and strategic plan presentations by management to our Board include consideration of the challenges and risks to our business. Our Board and management actively engage in discussions of these topics and utilize outside consultants as needed. Our Board oversees the assessment of our strategic plan risks as part of our strategic planning process. In addition, our Board periodically receives safety performance, operations, environmental, regulatory, legal and compliance reports.

Our Audit Committee oversees management's strategy and performance relative to our significant financial risks. In consultation with management, the independent auditors and the internal auditors, the Audit Committee discusses our risk assessment, risk management and credit policies and reviews significant financial risk exposures, along with steps management has taken to monitor, mitigate and report such exposures. At least twice a year, our Chief Risk Officer provides a Risk Report and our Treasurer provides a Credit Report to the Audit Committee. We have a Credit Policy that establishes guidelines, controls and limits to manage and mitigate credit risk within established risk tolerances.

Our Compensation Committee has an executive compensation philosophy that provides the foundation for our executive compensation program. The executive compensation philosophy states that the executive pay program should be market-based and maintain an appropriate and competitive balance between fixed and variable pay elements, short-term and long-term compensation and cash and stock-based compensation. The Compensation Committee establishes company-specific performance goals with potential incentive payouts for our executive officers to motivate and reward performance, consistent with our long-term success. The target compensation for our senior officers is weighted in favor of long-term incentives, aligning performance incentives with long-term results for our shareholders. Our Compensation Committee also sets minimum performance thresholds and maximum payouts in the incentive programs and maintains the discretion to reduce awards if excessive risk is taken. Stock ownership guidelines established for all of our officers require our executives to hold 100 percent of all shares awarded to them (net of share withholding for taxes and, in the case of cashless stock option exercises, net of the exercise price and withholding for taxes) until established stock ownership guidelines are achieved, and the Company prohibits hedging or pledging of stock Our Compensation Committee also includes "clawback" provisions in our incentive plans, which may require an executive to return incentives received, if the Compensation Committee determines, in its discretion, that the executive engaged in specified misconduct or wrongdoing or in the event of certain financial restatements.

In addition, management periodically conducts, and our Compensation Committee reviews, a risk assessment of the Company's compensation policies and practices for all employees. This was last done in December 2017 and there have been no material changes in our policies and practices since that time. Key members of human resources, legal, risk, finance, audit and operations departments were included in the review to ensure accuracy and completeness of the scope and findings. The assessment demonstrated that our compensation programs are designed to minimize financial and reputational risks and do not create risks that are reasonably likely to have a material adverse effect on the Company.

Our management is responsible for day-to-day risk management and operates under an ERM program that addresses strategic, operational, financial and compliance risks. The ERM program includes practices to identify risks, assesses the impact and probability of occurrence, and develops action plans to prevent the occurrence or mitigate the impact of the risk. The ERM program includes regular reporting to our senior management team and includes monitoring and testing by the Chief Risk Officer and Risk Management, Compliance and Internal Audit groups. The Chief Risk Officer reviews the overall ERM program with the Board of Directors on a regular basis.

We believe the division of risk management responsibilities described above is an effective approach for addressing the risks facing our Company.

Director Nominees

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

Ms. McAllister and Mr. Jensen are standing for election by shareholders for the first time at this annual meeting. Both director nominees were identified as candidates by a third-party search firm. The firm was engaged to assist in the identification and assessment of director candidates based on criteria developed by the Governance Committee.

Shareholders who intend to nominate persons for election to the Board of Directors must provide timely written notice of the nomination in accordance with Article I, Section 9 of our Bylaws. Generally, our Corporate Secretary must receive the written notice at our executive offices at 7001 Mount Rushmore Road, P.O. Box 1400, Rapid City, South Dakota 57709, not less than 90 days nor more than 120 days prior to the anniversary date of the immediately preceding annual meeting of shareholders. For the 2021 shareholder meeting, those dates are January 28, 2021 and December 29, 2020. The notice must set forth at a minimum the information set forth in Article I, Section 9 of our Bylaws, including the shareholder's identity and status, contingent ownership interests, description of any agreement made with others acting in concert with respect to the nomination, specific information about the nominee and certain representations by the nominee to us.

Director Resignation Policies

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

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

In conformance with the Corporate Governance Guidelines, Mr. Vering provided notice that he would retire from his position as Managing Director of Lone Mountain Investments, Inc., effective December 31, 2019, and submitted a letter of resignation to the Board. The Governance Committee determined Mr. Vering's change in employment status would not impact his ability to perform his duties as a director and recommended the Board not accept his tendered resignation. Acting on the Committee's recommendation, the Board declined to accept Mr. Vering's resignation.

Corporate Governance Documents

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

Certain Relationships and Related Party Transactions

We recognize related party transactions can present potential or actual conflicts of interest and create the appearance that decisions are based on considerations other than the best interests of us and our shareholders. Accordingly, as a general matter, it is our preference to avoid related party transactions. Nevertheless, we recognize that there are situations where related party transactions may be in, or may not be inconsistent with, the best interests of us and our shareholders, including but not limited to situations where we may obtain products or services of a nature, quantity or quality, or on other terms, that are not readily available from alternative sources or when we provide products or services to related parties on an arm's length basis on terms comparable to those provided to unrelated third parties or on terms comparable to those provided to employees generally. Therefore, our Board of Directors has adopted a policy for the review of related party transactions. This policy requires directors and officers to promptly report to our General Counsel all proposed or existing transactions in which the Company and they, or persons related to them, are parties or participants. Our General Counsel presents to our Governance Committee those transactions that may require disclosure pursuant to Item 404 of Regulation S-K (typically, those transactions that exceed $120,000). Our Governance Committee reviews the material facts presented and either approves or disapproves entry into the transaction. In reviewing the transaction, the Governance Committee considers the following factors, among other factors it deems appropriate: (i) whether the transaction is on terms no less favorable than terms generally available to an unaffiliated third party under the same or similar circumstances; (ii) the extent of the related party's interest in the transaction; and (iii) the impact on a director's independence in the event the related party is a director, an immediate family member of a director or an entity in which a director is a partner, shareholder or executive officer. There were no reportable related party transactions in 2019.

Delinquent Section 16(a) Reports

Based solely upon a review of our records and reports on Form 3, 4 and 5 filed with the SEC, we believe that during and with respect to 2019, all persons subject to the reporting requirements of Section 16(a) of the Securities Exchange Act of 1934, as amended, filed the required reports on a timely basis, except for a Form 4 for Mr. Mills related to an August 2019 transaction that was reported in December of 2019 and initial reports on Form 3 for Tony A. Jensen and Kathleen S. McAllister for November 1, 2019, the date they both became directors. At the time the Form 3 reports were due, Mr. Jensen and Ms. McAllister did not own any stock in our Company.

Communications with the Board

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

MEETINGS AND COMMITTEES OF THE BOARD

THE BOARD OF DIRECTORS

Our directors review and approve our strategic plan and oversee our management. Our Board of Directors held four in-person meetings and one telephonic meeting during 2019. Each regularly scheduled meeting of the Board includes an executive session of only independent directors. We encourage our directors to attend the annual shareholders' meeting. During 2019, each current director attended at least 75 percent of the combined total of Board meetings and Committee meetings on which the director served and all directors then serving attended the 2019 annual meeting of shareholders.

COMMITTEES OF THE BOARD

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

AUDIT COMMITTEE		
Committee Chair:		
Mark A. Schober	Total Meetings Held	
Additional Committee Members:	In-Person	Telephonic
Steven R. Mills, Robert P. Otto, John B. Vering	4	5

Primary Responsibilities

- assist the Board in fulfilling its oversight responsibility to our shareholders relating to the quality and integrity of our accounting, auditing and financial reporting practices;
- oversee the integrity of our financial statements, financial reporting process, systems of internal controls and disclosure controls regarding finance, accounting and legal compliance;
- review areas of potential significant financial risk to us;
- review consolidated financial statements and disclosures;
- appoint an independent registered public accounting firm for ratification by our shareholders;
- monitor the independence and performance of our independent registered public accountants and internal auditing department;
- pre-approve all audit and non-audit services provided by our independent registered public accountants;
- review the scope and results of the annual audit, including reports and recommendations of our independent registered public accountants;
- review the internal audit plan, results of internal audit work and our process for monitoring compliance with our Code of Business Conduct and other policies and practices established to ensure compliance with legal and regulatory requirements; and
- periodically meet, in private sessions, with our Chief Auditor, Chief Financial Officer, Chief Compliance Officer, other management, and our independent registered public accounting firm.

In accordance with the rules of the NYSE, all of the members of the Audit Committee are financially literate. In addition, the Board determined that Messrs. Mills, Schober and Vering have the requisite attributes of an "audit committee financial expert" as provided in regulations promulgated by the SEC, and that such attributes were acquired through relevant education and/or experience.

COMPENSATION COMMITTEE

Committee Chair:		
Michael H. Madison	Total Meetings Held	
Additional Committee Members:	In-Person	Telephonic
Rebecca B. Roberts, Teresa A. Taylor, Thomas J. Zeller	2	3

Primary Responsibilities

- discharge the Board of Directors' responsibilities related to executive and director compensation philosophy, policies and programs;
- perform functions required of directors in the administration of all federal and state laws and regulations pertaining to executive employment and compensation;
- consider and recommend for approval by the Board all executive compensation programs including executive benefit programs and stock ownership plans; and
- promote an executive compensation program that supports the overall objective of enhancing shareholder value.

The Compensation Committee has authority under its charter to retain and terminate compensation consultants, outside counsel and other advisors as the Committee may deem appropriate in its sole discretion. The Committee engaged Willis Towers Watson, an independent consulting firm, to conduct an annual review of our 2019 total compensation program for executive officers and directors. The Committee reviewed the independence of Willis Towers Watson and the individual representative of Willis Towers Watson who serves as a consultant to the Committee, in accordance with the SEC and NYSE requirements and the specific factors that the requirements cite. The Compensation Committee concluded that Willis Towers Watson is independent and Willis Towers Watson's performance of services raises no conflict of interest. The Committee's conclusion was based in part on a report that Willis Towers Watson provided to the Committee intended to reveal any potential conflicts of interest and a schedule provided by management of the type and amount of non-executive compensation services provided by Willis Towers Watson to the Company. During 2019, the cost of these non-executive compensation services was less than $25,000.

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

GOVERNANCE COMMITTEE		
Committee Chair:		
Rebecca B. Roberts	Total Meetings Held	
Additional Committee Members:	In-Person	Telephonic
Michael H. Madison, Steven R. Mills, John B. Vering, Thomas J. Zeller	3	1

Primary Responsibilities

- assess the size of the Board and membership needs and qualifications for Board membership;
- identify and recommend prospective directors to the Board to fill vacancies;
- review and evaluate director nominations submitted by shareholders, including reviewing the qualifications and independence of shareholder nominees;
- consider and recommend existing Board members to be renominated at our annual meeting of shareholders;
- consider the resignation of an incumbent director who makes a principal occupation change (including retirement) or who receives a greater number of votes "Withheld" than votes "For" in an uncontested election of directors and recommend to the Board whether to accept or reject the resignation;
- establish and review guidelines for corporate governance;
- recommend to the Board for approval committee membership and chairs of the committees;
- recommend to the Board for approval an independent director to serve as a Lead Director;
- review the independence of each director and director nominee;
- administer an annual evaluation of the performance of the Board and each Committee and a biennial evaluation of each individual director; and
- ensure that the Board oversees the evaluation and succession planning of management.

DIRECTOR COMPENSATION

DIRECTOR FEES

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

In setting non-employee director compensation, the Compensation Committee recommends the form and amount of compensation to the Board of Directors, which makes the final determination. In considering and recommending the compensation of non-employee directors, the Compensation Committee considers such factors as it deems appropriate, including historical compensation information, level of compensation necessary to attract and retain non-employee directors meeting our desired qualifications and market data. In the review of director compensation in 2019, the Compensation Committee reviewed the NACD 2018-2019 Director Compensation Report and proxy peer group data to provide market information on non-employee director compensation including compensation structure, annual board and committee retainers, committee chair fees, and stock-based compensation. Based on this review, the cash retainer was increased effective January 1, 2020 to more closely align with the median director compensation for our peer utility companies. The fee structure for director fees in 2019 and the new fees effective January 1, 2020 are as follows:

	2019 Fees		Fees Effective January 1, 2020	
	Cash	Common Stock Equivalents	Cash	Common Stock Equivalents
Board Retainer	$80,000	$105,000	$85,000	$105,000
Lead Director Retainer	$25,000		$25,000	
Committee Chair Retainer				
Audit Committee	$15,000		$15,000	
Compensation Committee	$10,000		$10,000	
Governance Committee	$7,500		$7,500	
Committee Member Retainer				
Audit Committee	$10,000		$10,000	
Compensation Committee	$7,500		$7,500	
Governance Committee	$7,500		$7,500	

DIRECTOR COMPENSATION FOR 2019 AND COMMON STOCK EQUIVALENTS OUTSTANDING AS OF DECEMBER 31, 2019[(1)]

Name[(2)]	Fees Earned or Paid in Cash	Stock Awards[(3)]	Total	Number of Common Stock Equivalents Outstanding at December 31, 2019[(4)]
Tony A. Jensen[(5)]	$13,333	$17,500	$30,833	115
Michael H. Madison	$105,000	$105,000	$210,000	12,718
Kathleen A. McAllister [(5)]	$13,333	$17,500	$30,833	115
Steven R. Mills	$116,667	$105,000	$221,667	14,104
Robert P. Otto	$90,000	$105,000	$195,000	4,431
Rebecca B. Roberts	$102,500	$105,000	$207,500	15,152
Mark A. Schober	$100,000	$105,000	$205,000	6,595
Teresa A. Taylor	$87,500	$105,000	$192,500	4,918
John B. Vering	$105,833	$105,000	$210,833	28,007
Thomas J. Zeller	$95,000	$105,000	$200,000	33,310

(1) Our directors did not receive any stock option awards, non-equity incentive plan compensation, pension benefits or perquisites in 2019 and did not have any stock options outstanding at December 31, 2019.

(2) Mr. Emery, our Executive Chairman, and Mr. Evans, our President and CEO, are not included in this table because they are our employees and thus receive no compensation for their services as directors. Mr. Emery's and Mr. Evans' compensation received as employees is shown in the Summary Compensation Table for our Named Executive Officers.

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

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

(5) Mr. Jensen and Ms. McAllister became members of our board effective November 1, 2019; consequently their fees earned and stock award fair values reflect a partial year of service.

DIRECTOR STOCK OWNERSHIP GUIDELINES

Each member of our Board of Directors is required to apply at least 50 percent of his or her annual cash retainer toward the purchase of shares of common stock until the director has accumulated shares of common stock or common stock equivalents equal to five times the annual cash Board retainer. Currently, all of our directors have met the stock ownership guideline except for Mr. Jensen and Ms. McAllister, who have been on the Board for less than a year.

SECURITY OWNERSHIP OF MANAGEMENT AND PRINCIPAL SHAREHOLDERS

The following tables set forth the beneficial ownership of our common stock as of February 25, 2020 for each director, each executive officer named in the Summary Compensation Table, all of our directors and executive officers as a group and each person or entity known by us to beneficially own more than five percent of our outstanding shares of common stock. Beneficial ownership includes shares a director or executive officer has or shares the power to vote or transfer. There were no stock options outstanding for any of our directors or executive officers as of February 25, 2020.

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

Name of Beneficial Owner(1)	Shares of Common Stock Beneficially Owned(2)	Directors Common Stock Equivalents(3)	Total	Percentage
Outside Directors				
Tony A. Jensen	176	115	291	*
Michael H. Madison	15,506	12,718	28,224	*
Kathleen S. McAllister	176	115	291	*
Steven R. Mills	13,127	14,104	27,231	*
Robert P. Otto	2,095	4,431	6,526	*
Rebecca B. Roberts	4,691	15,152	19,843	*
Mark A. Schober	3,241	6,595	9,836	*
Teresa A. Taylor	2,201	4,918	7,119	*
John B. Vering	11,022	28,007	39,029	*
Thomas J. Zeller	10,684	33,310	43,994	*
Named Executive Officers				
Scott A. Buchholz	40,131		40,131	*
David R. Emery	101,346		101,346	*
Linden R. Evans	119,684		119,684	*
Brian G. Iverson	28,730		28,730	*
Richard W. Kinzley	44,365		44,365	*
All directors and executive officers as a group (18 persons)	438,697	119,466	558,163	1.0%

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

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

(2) Includes restricted stock held by the following executive officers for which they have voting power but not investment power: Mr. Buchholz 3,323 shares; Mr. Emery 6,042 shares; Mr. Evans 20,291 shares; Mr. Iverson 5,498 shares; Mr. Kinzley 7,053 shares; and all directors and executive officers as a group 52,130 shares.

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

PRINCIPAL SHAREHOLDERS

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

Name and Address	Shares of Common Stock Beneficially Owned	Percentage
BlackRock, Inc.[1] 55 East 52nd Street New York, NY 10055	8,582,829	14.0%
The Vanguard Group Inc.[2] 100 Vanguard Blvd. Malvern, PA 19355	6,771,694	11.1%
State Street Corporation[3] State Street Financial Center One Lincoln Street Boston, MA 02111	4,998,712	8.1%
Wellington Management Group LLP[4] 280 Congress Street Boston, MA 02210	3,076,006	5.0%

(1) Information is as of December 31, 2019, and is based on a Schedule 13G/A filed on February 4, 2020.
(2) Information is as of December 31, 2019, and is based on a Schedule 13G/A filed on February 12, 2020.
(3) Information is as of December 31, 2019, and is based on a Schedule 13G filed on February 13, 2020.
(4) Information is as of December 31, 2019, and is based on a Schedule 13G filed on January 28, 2020.

PROPOSAL 2 RATIFICATION OF APPOINTMENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The firm of Deloitte & Touche LLP, independent registered public accountants, conducted the audit of Black Hills Corporation and its subsidiaries for 2019. Representatives of Deloitte & Touche LLP will be present at our annual meeting and will have the opportunity to make a statement, if they desire to do so, and to respond to appropriate questions.

Our Audit Committee has appointed Deloitte & Touche LLP to perform an audit of our consolidated financial statements and those of our subsidiaries for 2020 and to render their reports. In determining whether to recommend to the full Board the reappointment of Deloitte & Touche LLP as our independent auditor, the Audit Committee considered the following:

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

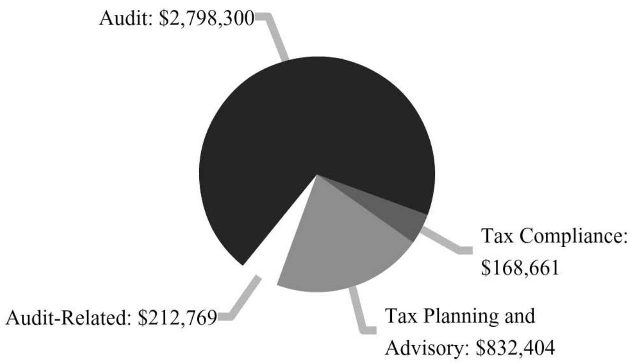
The Board of Directors recommends ratification of the Audit Committee's appointment of Deloitte & Touche LLP. The appointment of Deloitte & Touche LLP as our independent registered public accounting firm for 2020 will be ratified if the votes cast "For" exceed the votes cast "Against." Abstentions will have no effect on such vote. If shareholder approval for the appointment of Deloitte & Touche LLP is not obtained, the Audit Committee will reconsider the appointment.

The Board of Directors recommends a vote *FOR* ratification of the appointment of Deloitte & Touche LLP to serve as our independent registered public accounting firm for 2020.

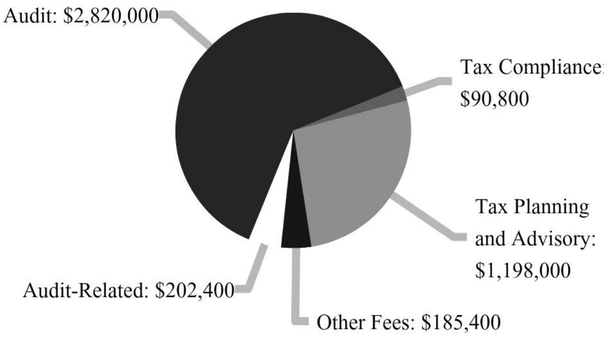
FEES PAID TO THE INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The following chart sets forth the aggregate fees for services provided to us for the years ended December 31, 2019 and 2018 by our independent registered public accounting firm, Deloitte & Touche LLP:

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



2018 Deloitte & Touche LLP Fees
Total $4,496,600



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

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

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

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

Other Fees
Fees for advising the Company as it defined the Governance Risk and Compliance ("GRC") requirements for a GRC software tool.

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

AUDIT COMMITTEE REPORT

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

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

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

In fulfilling its oversight responsibilities for 2019, the Audit Committee, among other things:

- Reviewed and discussed the audited financial information contained in the Annual Report on Form 10-K with management and our independent auditors prior to public release.
- Reviewed and discussed with our independent auditors their judgments as to the quality, not just the acceptability, of our critical accounting principles and estimates and all other communications required to be discussed with the Audit Committee under generally accepted auditing standards, including the matters required to be discussed by the applicable requirements of the Public Company Accounting Oversight Board and the SEC.
- Reviewed and discussed with management, our internal auditors and our independent auditors management's report on internal control over financial reporting, including the significance and status of control deficiencies identified by management and the results of remediation efforts undertaken, to determine the effectiveness of internal control over financial reporting at December 31, 2019.
- Reviewed with our independent auditors their report on the Company's internal control over financial reporting at December 31, 2019, including the basis for their conclusions.
- Reviewed and pre-approved all audit and non-audit services and fees provided to the Company by our independent auditors and considered whether the provision of such non-audit services by our independent auditors is compatible with maintaining their independence.
- Discussed with our internal and independent auditors their audit plans, audit scope and identification of audit risks and reviewed the results of internal audit examinations.
- Reviewed and discussed the interim financial information contained in each quarterly earnings announcement and Quarterly Report on Form 10-Q with management and our independent auditors prior to public release.
- Received and reviewed periodic corporate compliance and financial risk reports, including credit and hedging activity.
- Held private sessions with our independent auditors, Chief Auditor, Chief Financial Officer and Controller, and Chief Compliance Officer.
- Received the written disclosures and the letter from our independent auditors required by the applicable requirements of the Public Company Accounting Oversight Board regarding the independent auditors' communications with the Committee concerning independence and discussed the independence of Deloitte & Touche LLP with them.
- Concluded Deloitte & Touche LLP is independent based upon the above considerations.

Based upon the reviews and discussions referred to above, the Audit Committee recommended to the Board that our audited consolidated financial statements be included in our Annual Report on Form 10-K for the year ended December 31, 2019 filed with the SEC. The Audit Committee also recommended and the Board reappointed Deloitte & Touche LLP as our independent registered public accounting firm for 2020. Shareholders are being asked to ratify that selection at the 2020 Annual Meeting.

THE AUDIT COMMITTEE

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

COMPENSATION DISCUSSION AND ANALYSIS

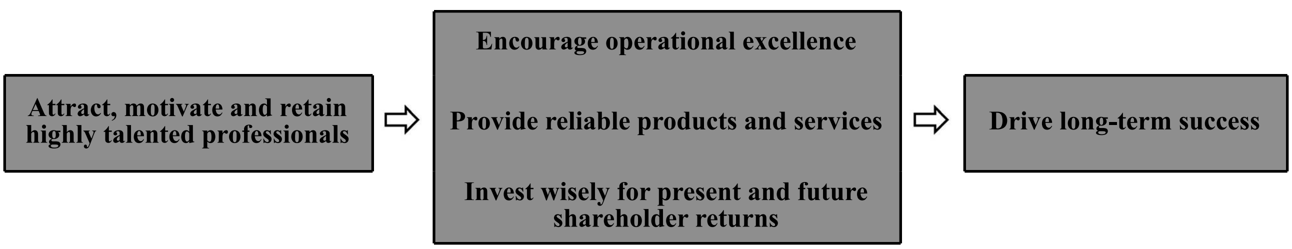
INTRODUCTION

This Compensation Discussion and Analysis describes our overall executive compensation policies and practices and specifically explains the compensation-related actions taken with respect to 2019 compensation for our executive officers included in the Summary Compensation Table (our "Named Executive Officers"). Our Named Executive Officers, based on 2019 positions and compensation levels, are:

Name Executive Officers	Title	Reference
David R. Emery	Executive Chairman	Emery, Chair
Linden R. Evans	President and Chief Executive Officer	Evans, CEO
Richard W. Kinzley	Sr. Vice President and Chief Financial Officer	Kinzley, CFO
Brian G. Iverson	Sr. Vice President, General Counsel and Chief Compliance Officer	Iverson, GC
Scott A. Buchholz	Sr. Vice President and Chief Information Officer	Buchholz, CIO

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

OVERALL GOAL



EXECUTIVE COMPENSATION PROGRAM DESIGN OBJECTIVES

Attract, retain, motivate and encourage the development of highly qualified executives

Provide competitive compensation

Promote the relationship between pay and performance

Promote corporate performance that is linked to our shareholders' interests

Recognize and reward individual performance

2019 ACCOMPLISHMENTS

Black Hills Corporation reported solid operational and financial performance in 2019. Substantial progress was made on our strategic initiatives and we continued to lay a solid foundation for strong future earnings growth. Significant accomplishments for the year included:

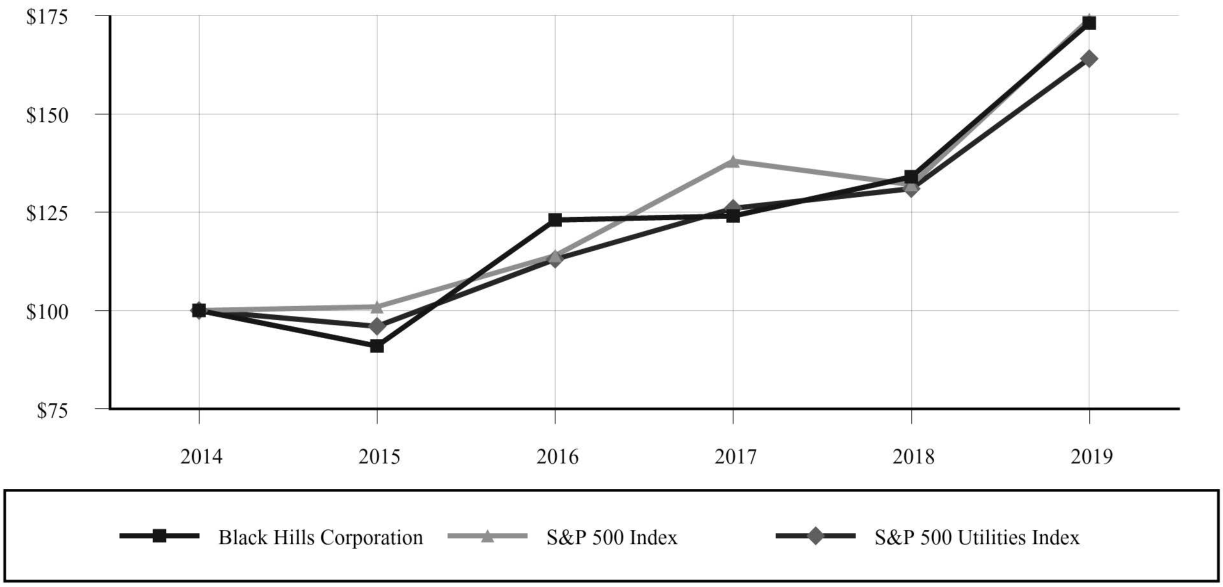
- Increased the annual dividend for the 49th consecutive year, one of the longest records in the utility sector;
- Completed significant financing activity, including:
  - Issued $400 million of 3.05 percent 10-year senior notes due 2029 and $300 million of 3.875 percent 30-year senior notes due 2049;
  - Issued 1.3 million shares of new common stock for net proceeds of $99 million under our at-the-market equity offering program;

  to accomplish our long-term objective of investing to meet the needs of our Customers;
- Executed a successful CEO transition;
- Invested in our utility infrastructure and systems:
  - Deployed $850 million in capital projects;
  - Completed construction of the 60 MW Busch Ranch II wind project;
  - Completed construction of the 12-inch 35-mile Natural Bridge pipeline that interconnects a supply point near Douglas, Wyoming to facilities near Casper, Wyoming;
  - Completed the construction of the final 94 miles of a 175-mile 230 kV transmission line from Rapid City, South Dakota to Segall, Nebraska;
- Executed a number of regulatory accomplishments;
  - Successfully completed a rate review request for Wyoming Gas;
  - Received approvals for South Dakota Electric’s and Wyoming Electric’s Renewable Ready Service Tariffs and the related jointly-filed certificate of public convenience and necessity to construct the Corriedale Wind Energy Project;
  - Received approval to consolidate the rates, tariffs and services of Wyoming Gas’ four gas distribution territories;
  - Received approval to legally consolidate Nebraska Gas’ two natural gas distribution companies;
  - Filed a request with FERC for approval of a new 20-year power purchase agreement between Black Hills Wyoming and affiliate Wyoming Electric;
  - Issued a request for proposals for Colorado Electric’s Renewable Advantage program, to potentially add up to 200 megawatts of renewable energy resources to its southern Colorado system;
- Provided the safe and reliable service our communities and customers depend on and achieved several notable operations performance metrics:
  - Earned 1st quartile reliability ranking for our three electric utilities compared to industry averages;
  - Achieved a safety performance total case incident rate of 1.25 compared to an industry average of 1.9;
  - Achieved a safety performance preventable motor vehicle incident rate of 2.48 compared to an American Gas Association reported average of 3.11;
  - Achieved a 13 percent Net Promotor Score improvement over 2018;
  - Recognized as a “Gold Leader” in Colorado for achieving significant goals in environmental improvement and sustainability;
  - Received Star Worksite status, the highest OSHA Voluntary Protection Program status, for implementing and maintaining effective safety and health management systems at our Pueblo Airport Generating Station in Pueblo, Colorado; and
  - Received an award from the State of Wyoming for ten years without a lost-time accident at our mine and received the Mine Safety and Health Administration’s Certificate of Achievement for no lost-time accidents.

RETURN TO SHAREHOLDERS

The following chart shows how a $100 investment in the Company's common stock on December 31, 2014 would have grown to $172 on December 31, 2019, with dividends reinvested. The chart also compares the total shareholder return on the Company's common stock to the same investment in the S&P 500 Index and S&P 500 Utilities Index over the same period.

Comparison of 5 Year Cumulative Total Shareholder Return



2019 PERFORMANCE RESULTS

Our corporate financial and safety performance goals are used as measures to determine awards under our variable pay programs. The following table summarizes our 2019 performance measures and results.

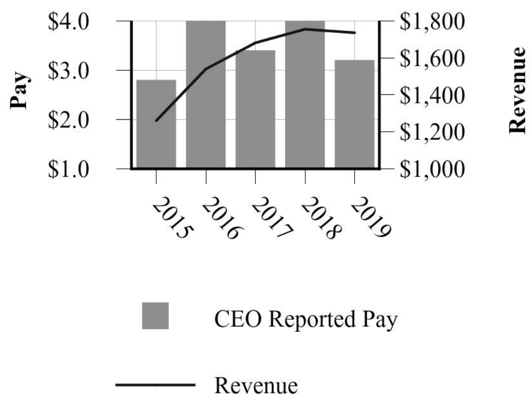
Pay Element	Performance Measure	2019 Results
Short-term Incentive: Payout of 107% of Target		
80 Percent	EPS from ongoing operations, as adjusted, target set at $3.44; threshold set at $3.10	$3.53 per share for incentive plan purposes
10 Percent	Total Case Incident Rate (TCIR), target set at 1.1; threshold set at 1.3	TCIR 1.25
10 Percent	Preventable Motor Vehicle Incident (PMVI), target set at 1.7; threshold set at 2.0	PMVI: 2.45
Long-term Incentive: Payout of 59% of Target		
Performance Share Award	Total Shareholder Return (TSR) relative to our Performance Peer Group measured over a three-year period	TSR 37% 36th Percentile Ranking in Performance Peer Group

PAY FOR PERFORMANCE

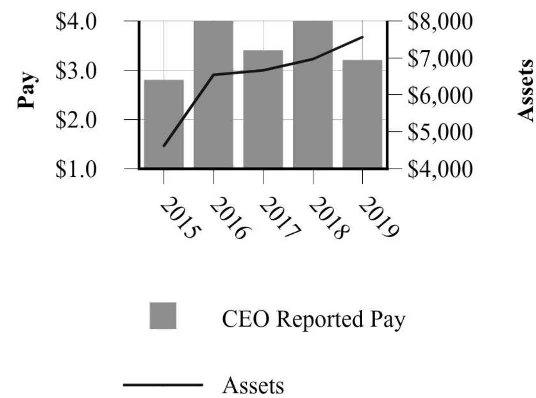
A key component of our executive compensation program is to link pay to performance.

The charts below illustrate the directional relationship between the compensation of our CEO (Mr. Emery for 2015 through 2018, and Mr. Evans for 2019), as reported in the Summary Compensation Table (excluding the change in pension value) and the growth in our Company for the last five years.

CEO Reported Pay vs. Revenue
(in millions)

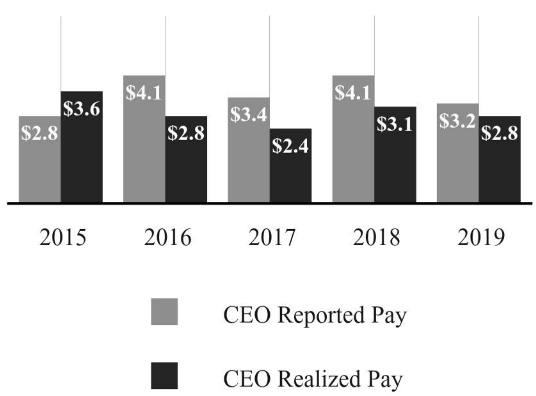


CEO Reported Pay vs. Assets
(in millions)

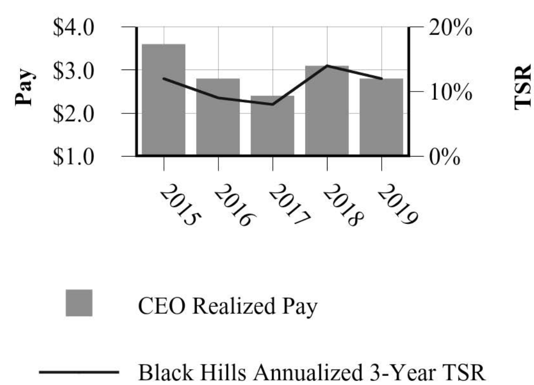


Since a large percentage of the CEO's pay as reported in the Summary Compensation Table represents potential pay, we believe it is also important to look at pay actually realized each year. In addition, since over 50 percent of our CEO pay is tied to Company performance, it is important to look at his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

CEO Reported vs. Realized Pay
(in millions)



CEO Realized Pay
vs. Annualized 3-Year TSR
(in millions)



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

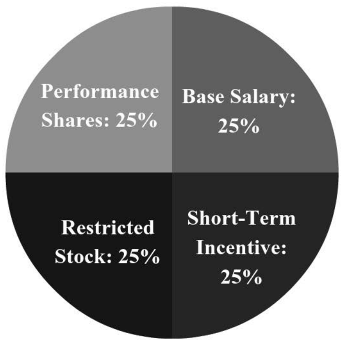
Realized pay includes base salary, actual annual incentive earned and all other compensation, each as reported in the Summary Compensation Table, and the value of long-term performance compensation paid and stock awards vested in the applicable year.

KEY EXECUTIVE COMPENSATION OBJECTIVES

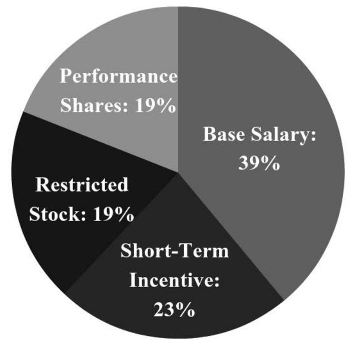
Overall, our goal is to target total direct compensation (the sum of base salary, short-term incentive at target and long-term incentive at target) at the median of the appropriate market when our operating results approximate average performance in relation to our peers.

Our executive compensation is designed to maintain an appropriate and competitive balance between fixed and variable compensation components, short-and long-term compensation, and cash and stock-based compensation.

CEO 2019 Target Pay Mix



Other NEOs 2019 Target Pay Mix(1)



Variable	75%	Variable	61%
Linked to Share Value	50%	Linked to Share Value	38%

(1) Mr. Emery's compensation is excluded from the target pay mix as he was not eligible for incentive pay in 2019.

We believe that the performance basis for determining compensation should differ by each reward component – base salary, short-term incentive and long-term incentive. Incentive measures (short-term and long-term) should emphasize objective, quantitative operating measures. The performance measures for our incentive compensation plans are discussed below.

SETTING EXECUTIVE COMPENSATION

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

Analyze executive compensation market data to ensure market competitiveness

Review the components of executive compensation, including base salary, short-term incentive, long-term incentive, retirement and other benefits

Review total compensation mix and structure

Review executive officer performance, responsibilities, experience and other factors cited above to determine individual compensation levels

Market Compensation Analysis

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

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

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

The Committee used the services of Willis Towers Watson to evaluate 2019 compensation. Willis Towers Watson gathered data from nationally recognized survey providers, as well as specific peer companies through public filings, which included:

i. Willis Towers Watson's 2018 Compensation Data Bank (energy services and general industry); and
ii. 23 peer companies representing the utility and energy industry.

The 23 peer companies ranged in annual revenue size from approximately $563 million to $6.6 billion, with the median at $2.0 billion. The Company's 2018 revenue was $1.7 billion. The survey data was adjusted for our relative revenue size using regression analysis. Our compensation peer companies included in the analysis for 2019 compensation decisions were:

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

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

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

Components of Executive Compensation

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

An important component of the executives' total compensation is derived from incentive compensation. Incentive compensation is intended to motivate and encourage our executives to drive performance and achieve superior results for our shareholders. The Committee periodically reviews information provided by the compensation consultant to determine the appropriate level and mix of incentive compensation. Actual income in the form of incentive compensation is realized by the executive as a result of achieving Company goals and overall stock performance. The Committee believes that a significant portion of total target compensation should be comprised of incentive compensation. In order to reward long-term growth while still encouraging short-term results, the Committee establishes incentive targets that emphasize long-term compensation at a greater level than short-term compensation.

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

As noted previously, effective January 1, 2019 and related to a long-term executive succession plan, Mr. Emery was named Executive Chairman and Mr. Evans was named President and CEO. The changes in duties were reflected in corresponding changes in compensation.

Base Salary. Base salaries for all officers are reviewed annually. We also adjust the base salary of our executives at the time of a promotion or material change in job responsibility, as appropriate. Evaluation of 2019 base salary adjustments occurred in January 2019. The base salary component of each position was compared to the median of the market data provided by the compensation consultant. The market data indicated that although competitive positioning has decreased from the consultant's previous analysis, the salaries generally aligned with the utility industry median and below comparable general industry levels. The actual base salary of each officer was determined by the executive's performance, the experience level of the officer, the executive's current position in a market-based salary range, and internal pay relationships. As Executive Chair, Mr. Emery no longer participates in new short or long-term incentive plans. His compensation is composed only of base salary.

	2018 Base Salary	2019 Base Salary
Emery, Chair	$820,000	$1,300,000
Evans, CEO	$530,000	$750,000
Kinzley, CFO	$381,000	$420,000
Iverson, GC	$350,000	$375,000
Buchholz, CIO	$320,000	$340,000

Short-Term Incentive. Our Short-Term Incentive Plan is designed to recognize and reward the contributions of individual executives as well as the contributions that group performance makes to overall corporate success. In 2019, the Committee recommended and the Board approved including safety performance metrics as components of the short-term incentive goals. The 2019 short-term incentive was based eighty percent on earnings per share targets and twenty percent on safety performance targets. The Committee believes that these performance measures closely align interests with shareholders and foster teamwork and cooperation within the officer team. The short-term incentive, after applicable tax withholding, is distributed to the officer in the form of 50 percent stock and 50 percent cash, unless the officer has met his or her stock ownership guideline, in which case he or she may elect to receive the total award in cash, after deductions and applicable tax withholding. Target award levels are established as a percentage of each participant's base salary. A target award is typically comparable to the average short-term incentive target award of the Performance Peer Group at the 50th percentile level. The actual payout will vary, based on attainment of pre-established performance goals, between 50 and 200 percent of the individual executive's short-term incentive target award level.

The Committee approves the target level for each officer in January, which applies to performance in the upcoming plan year. Target levels are derived in part from competitive data provided by the compensation consultant and in part by the Committee's judgment regarding internal equity, retention and an individual executive's expected contribution to the achievement of our strategic objectives. As Executive Chairman, Mr. Emery does not participate in the Company's Short-Term Incentive Plan. The target levels for the positions held by our other Named Executive Officers are shown below:

Short-Term Incentive Target				
	2018		2019	
	% Amount	$ Amount	% Amount	$ Amount
Emery, Chair	110%	$902,000	—	—
Evans, CEO	70%	$371,000	100%	$750,000
Kinzley, CFO	60%	$228,600	65%	$273,000
Iverson, GC	55%	$192,500	60%	$225,000
Buchholz, CIO	50%	$160,000	50%	$170,000

The threshold, target and maximum payout levels for our Named Executive Officers under the 2019 Short-Term Incentive Plan are shown in the Grants of Plan Based Awards in 2019 table on page 41, under the heading "Estimated Future Payouts Under Non-Equity Incentive Plan Awards."

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

The Committee selected an earnings per share goal based on ongoing operations, as adjusted, for 2019, and two safety performance goals. These goals meet the objectives of the plan, including:

Align the interests of the plan participants and the shareholders with a corporate-wide component

Motivate employees and support the corporate compensation philosophy

Provide an incentive reflective of core operating performance by adjusting for unique one-time events

Ensure "buy-in" from participants with easily understood metrics

Meet the performance objectives of the plan to achieve over-time, an average payout equal to market competitive levels

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

The Committee approved the goals for 2019 for the senior officers as follows:

2019 Short-Term Incentive Metrics				
		Guidelines		
Incentive	Value	Threshold	Target	Maximum
EPS from ongoing operations, as adjusted	80%	$3.10	$3.44	$3.78
Total Case Incident Rate (TCIR)	10%	1.3	1.1	0.9
Preventable Motor Vehicle Incidents (PMVI)	10%	2.0	1.7	1.4
Payout percentage of target for each metric		50%	100%	200%

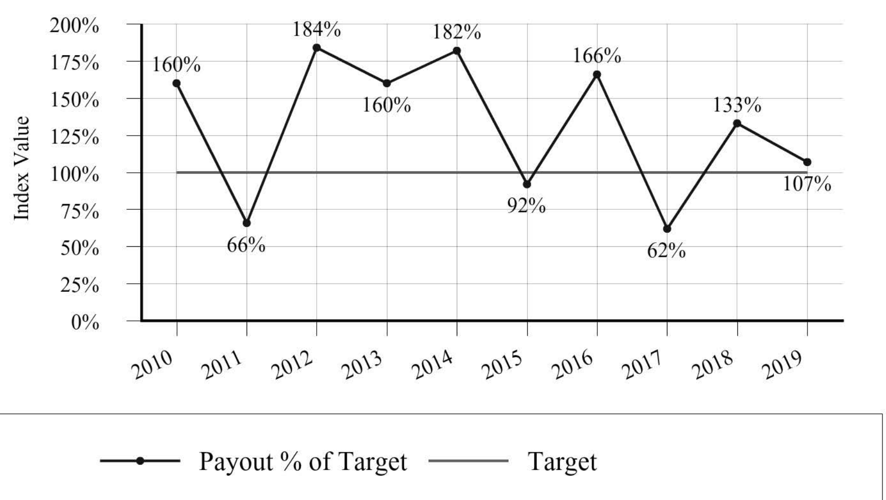
On January 28, 2020, the Committee approved a payout of 107 percent of target under the 2019 Short-Term Incentive Plan. The payout was based for incentive plan purposes on the attainment of the following:

- Our 2019 earnings per share were $3.53 per share, which was above our target earnings per share goal, resulting in a payout of 126 percent for 80 percent of the target incentive.
- Our 2019 TCIR was 1.25, which was above our target but below our threshold, which resulted in a payout of 63 percent for 10 percent of the target incentive.
- Our 2019 PMVI was 2.45, which exceeded our threshold and resulted in no payout of 10 percent of the target incentive.

Earnings from ongoing operations, as adjusted, for incentive plan purposes were the same as earnings per share from continuing operations, as adjusted, reported externally to our investors (and reconciled to GAAP earnings per share in Appendix A). For 2019, actual adjustments included impairment of an oil and gas investment, which is not indicative of ongoing performance and accordingly was reflected as an as-adjusted basis.

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

Short-Term Incentive Payout % of Target



Actual awards made to each of our Named Executive Officers under the Short-Term Incentive Plan for 2019 are included in the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table on page 39.

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

Promote corporate goals by linking the personal interests of participants to those of our shareholders

Provide participants with an incentive for excellence in individual performance

Promote teamwork among participants

Motivate, retain, and attract the services of participants who make significant contributions to our success by allowing participants to share in such success

Meet the performance objectives of the plan to achieve over-time, an average payout equal to market competitive levels

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

The value of long-term incentives awarded is based primarily on competitive market-based data presented by the compensation consultant to the Committee, the impact each position has on our shareholder return and internal pay relationships. The actual amount realized will vary from the awarded target amounts. The Committee approved the target long-term incentive compensation level for each officer in January 2019. As Executive Chair, Mr. Emery does not participate in our long-term incentive plan. The 2019 long-term incentive was adjusted for the balance of the Named Executive Officers to increase competitiveness within the market median compensation levels.

NEO Long-Term Incentive Target Compensation		
	2018	2019
Emery, Chair	$1,900,000	—
Evans, CEO	$840,000	$1,500,000
Kinzley, CFO	$480,000	$510,000
Iverson, GC	$375,000	$390,000
Buchholz, CIO	$240,000	$240,000

2019 NEO Long-Term Incentive Compensation as a Percentage of Base Salary					
	Emery, Chair	**Evans, CEO**	**Kinzley, CFO**	**Iverson, GC**	**Buchholz, CIO**
% of Base Salary	-	200%	121%	104%	71%

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

Performance shares are used to deliver 50 percent of the long-term incentive award amounts, with the remaining 50 percent delivered in the form of restricted stock that vests ratably over three years. The actual shares of performance shares and restricted stock granted in 2019 are reflected in the tables in the *Performance Shares* and *Restricted Stock* sections that follow.

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

The Committee, with the guidance of Willis Towers Watson, periodically conducts a review of the market competitiveness of our performance share plans. A summary of the performance criteria for each plan period is summarized in the table below.

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

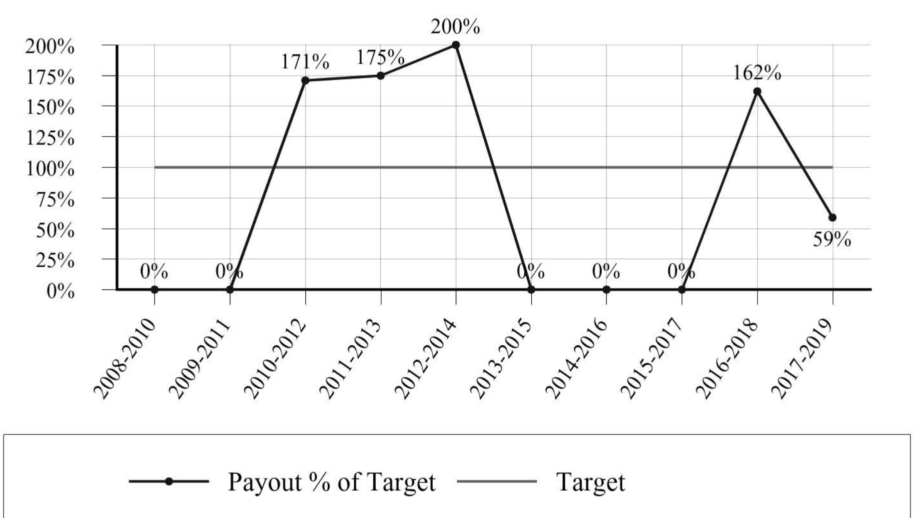
In addition, beginning with the 2017-2019 performance plan, our plans provide: (i) a threshold payout if relative TSR performance is below threshold but at 35 percent or higher; and (ii) the performance share plan payout is capped at 100 percent of target if TSR is negative. The additional provisions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

The performance awards and dividend equivalents, if earned, are paid 50 percent in cash and 50 percent in common stock. All payroll deductions and applicable tax withholding related to the award are withheld from the cash portion. Performance share target grant values for new performance periods are approved in January of each year.

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

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

Performance Share Payout % of Target



Each performance share period extends for three years. For the recently completed performance period, January 1, 2017 to December 31, 2019, our total shareholder return was 37 percent, which ranked at the 36th percentile of our Performance Peer Group, resulting in a payout at 59 percent of target. Consistent with prior years, the Committee awarded 50 percent of the Named Executive Officers' long-term incentive in restricted stock that ratably vests over three years.

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

	January 1, 2018 to December 31, 2020 Performance Period	January 1, 2019 to December 31, 2021 Performance Period
Emery, Chair	16,074	—
Evans, CEO	7,107	11,524
Kinzley, CFO	4,061	3,918
Iverson, GC	3,173	2,996
Buchholz, CIO	2,030	1,844

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

Restricted Stock. Restricted stock awarded as long-term incentives vest one-third each year over a three-year period, and automatically vest in their entirety upon death, disability or a change in control. Dividends are paid on the restricted stock. Unvested restricted stock is forfeited if an officer's employment is terminated for any reason other than death, disability or in the event of a change in control.
The number of shares of restricted stock awarded in 2019 for each of our Named Executive Officers is shown below and is included in the Grants of Plan Based Awards in 2019 table under the heading "All Other Stock Awards: Number of Shares of Stock or Units" and "Grant Date Fair Value of Stock Awards" on page 41.

	Long-Term Incentive
Emery, Chair	—
Evans, CEO	10,667
Kinzley, CFO	3,627
Iverson, GC	2,773
Buchholz, CIO	1,707

Performance Evaluation

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

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

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

Compensation Arrangements Regarding Chief Executive Officer Transition

Effective December 31, 2018, Mr. Emery retired as Chief Executive Officer and Mr. Evans was appointed President and Chief Executive Officer, effective January 1, 2019. Mr. Emery continues to serve the Company as Executive Chairman until May 1, 2020. This leadership change was the result of a comprehensive, multi-year, board-led succession planning process.

The Compensation Committee engaged its compensation consultant, Willis Towers Watson, to conduct an extensive study on market compensation for an incoming Chief Executive Officer and the transition role of an Executive Chairman. The compensation consultant provided the Committee a Chief Executive Officer benchmarking report that regressed the proxy data of our Compensation Peer Group. The compensation consultant also advised the Committee that pay for a new Chief Executive Officer normally starts at the lower end of the competitive range and increases to the middle of the range within a few years, depending on performance and experience; and Executive Chairman compensation should take into account the change in roles and responsibilities and the level of support expected to be provided to the new Chief Executive Officer, while also maintaining stability and consistency at the board level during the transition. The Committee recommended and the Board approved the following compensation packages, effective January 1, 2019:

- As Executive Chairman, Mr. Emery received an annual salary equal to $1,300,000 in 2019, decreasing to an annual salary equal to $480,000, effective January 1, 2020 (of which he will receive $160,000 for the service period of January 1, 2020 until his retirement on May 1, 2020). In addition, he will continue to receive all full-time employee and officer benefits and perquisites until his retirement as Executive Chairman on May 1, 2020. However, he no longer participates in the Company’s Short-Term Incentive Plan or receives new awards under the Long-Term Incentive Plan. As Executive Chairman, Mr. Emery’s stock ownership requirement is a fixed number of shares in an amount that is substantially similar to when he was our Chairman and CEO.

- As President and Chief Executive Officer, Mr. Evans’ base salary was $750,000 in 2019. In addition, Mr. Evans was eligible to receive an annual incentive based on 100 percent of his base salary in 2019 in accordance with the Company’s Short-Term Incentive Plan and $1,500,000 of target award value pursuant to the Company’s Long-Term Incentive Plan. These compensation actions resulted in a total target direct compensation level of $3,000,000 for Mr. Evans which was 91 percent of the market median.

Governance Best Practices

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

Summary

In total, the Committee believes that the 2019 compensation actions, decisions and outcomes strongly reflect and reinforce our compensation philosophy and, in particular, emphasize the alignment between compensation and both performance and shareholder interests. At our 2019 annual meeting, shareholders owning 97 percent of the shares voted on this matter and approved our executive compensation for 2018, which we consider highly supportive of our current compensation philosophy. In connection with establishing the 2019 executive compensation program, the Board reviewed the results of the say on pay vote, as well as market data and performance indicators.

STOCK OWNERSHIP GUIDELINES

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

The guidelines are shown below.

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

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

2019 BENEFITS

Retirement Benefits. We maintain a variety of employee benefit plans and programs in which our executive officers may participate. We believe it is important to provide post-employment benefits to our executive officers and the benefits we provide approximate retirement benefits paid by other employers to executives in similar positions. The Committee periodically reviews the benefits provided, with assistance from its compensation consultant, to maintain a market-based benefits package. None of our Named Executive Officers received any pension benefit payments in 2019.

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

The 401(k) Retirement Savings Plan is offered to all our eligible employees and we provide matching contributions for certain eligible participants. All of our Named Executive Officers are participants in the 401(k) Retirement Savings Plan and received matching contributions in 2019. The matching contributions and the Retirement Contributions are included as “All Other Compensation” in the Summary Compensation Table on page 39.

We also provide nonqualified plans to certain officers because of Internal Revenue Code limitations imposed on the qualified plans. The level of retirement benefits provided by the Pension Plan and Nonqualified Plans for each of our Named Executive Officers is reflected in the Pension Benefits for 2019 table on page 45. Our contributions to the Nonqualified Deferred Compensation Plan are included in the All Other Compensation column of the Summary Compensation Table on page 39 and the aggregate Nonqualified Deferred Compensation balance at December 31, 2019 is reported in the Nonqualified Deferred Compensation for 2019 table on page 48. These retirement benefits are explained in more detail in the accompanying narrative to the tables.

Other Personal Benefits. We provide the personal use of a Company vehicle, executive health services, and limited reimbursement of financial planning services as benefits to our executive officers, and use of the corporate aircraft to go to outside board meetings for the Executive Chair. In 2019, retirement gifts were also provided to our Executive Chair consisting primarily of a piece of art and a trip to commemorate his service to the Company. The specific amount attributable to these benefits in 2019 is disclosed in the Summary Compensation Table on page 39. The Committee periodically reviews the other personal benefits provided to our executive officers and believes the current benefits are reasonable and consistent with our overall compensation program.

CHANGE IN CONTROL PAYMENTS

Our Named Executive Officers may also receive severance benefits in the event of a change in control. We have no employment agreements with our Named Executive Officers. However, change in control agreements are common among our Compensation Peer Group and the Committee and our Board of Directors believe providing these agreements to our corporate officers protects our shareholder interests in the event of a change in control by helping assure management focus and continuity. Our change in control agreements have expiration dates and our Board of Directors conducts a thorough review of the change in control agreements at each renewal period. Our current change in control agreements expire November 15, 2022. In general, our change in control agreements provide a severance payment of up to 2.99 times average compensation for Mr. Evans, and up to two times average compensation for the other Named Executive Officers, with the exception of Mr. Emery whose change in control agreement expired on November 15, 2019. The change in control agreements do not provide for excise tax gross-ups and contain a "double trigger," providing benefits in association with:

(1) a change in control, and

(2) (i) a termination of employment other than by death, disability or by us for cause, or

(ii) a termination by the employee for good reason.

See the Potential Payments upon Termination or Change in Control table on page 50 and the accompanying narrative for more information regarding our change in control agreements and estimated payments associated with a change in control.

TAX AND ACCOUNTING IMPLICATIONS

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

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

CLAWBACK POLICY

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

In addition, our award agreements for restricted stock and target performance shares include clawback provisions whereby the participant may be required to repay all income or gains previously realized in respect of such awards if his or her employment is terminated for cause, or if, within one year following termination of employment, the Board determines that the participant engaged in conduct prior to his or her termination that would have constituted the basis for a termination of employment for cause.

HEDGING POLICY

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

REPORT OF THE COMPENSATION COMMITTEE

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

THE COMPENSATION COMMITTEE

Michael H. Madison, Chair
Rebecca B. Roberts
Teresa A. Taylor
Thomas J. Zeller

SUMMARY COMPENSATION TABLE

The following table sets forth the total compensation paid or earned by each of our Named Executive Officers for the years ended December 31, 2019, 2018 and 2017. We have no employment agreements with our Named Executive Officers.

Name and Principal Position	Year	Salary	Stock Awards[(2)]	Non-Equity Incentive Plan Compensation[(3)]	Changes in Pension Value and Nonqualified Deferred Compensation Earnings [(4)]	All Other Compensation[(5)]	Total
David R. Emery[(1)]	2019	$1,220,000	$—	$—	$4,123,060	$112,009	$5,455,069
Executive Chairman	2018	$820,000	$1,943,679	$1,196,503	$523,260	$140,256	$4,623,698
	2017	$812,000	$1,942,843	$560,232	$2,155,930	$92,930	$5,563,935
Linden R. Evans[(1)]	2019	$713,333	$1,541,811	$800,400	$110,158	$473,600	$3,639,302
President and Chief Executive Officer	2018	$530,000	$859,369	$492,132	$—	$306,330	$2,187,831
	2017	$523,333	$818,045	$230,428	$59,631	$385,948	$2,017,385
Richard W. Kinzley	2019	$413,500	$524,220	$291,346	$68,631	$254,366	$1,552,063
Sr. Vice President and Chief Financial Officer	2018	$381,000	$491,036	$303,238	$—	$195,249	$1,370,523
	2017	$378,000	$465,256	$141,983	$36,599	$250,572	$1,272,410
Brian G. Iverson	2019	$370,833	$400,825	$240,120	$31,927	$156,990	$1,200,695
Sr. Vice President and General Counsel	2018	$350,000	$383,678	$255,351	$—	$123,852	$1,112,881
	2017	$346,667	$357,856	$97,823	$17,736	$145,405	$965,487
Scott A. Buchholz	2019	$336,667	$246,720	$181,424	$756,325	$134,089	$1,655,225
Sr. Vice President and Chief Information Officer	2018	$320,000	$245,514	$212,240	$38,765	$111,285	$927,804
	2017	$317,500	$235,193	$99,376	$366,235	$133,407	$1,151,711

(1) Mr. Emery retired as our Chairman and Chief Executive Officer, effective December 31, 2018. He continues his full-time employment with the Company as Executive Chairman of the Board, through May 1, 2020. Mr. Evans was named President and Chief Executive Officer effective January 1, 2019. Previously, he was President and Chief Operating Officer.

(2) Stock Awards represent the grant date fair value related to restricted stock and performance shares that have been granted as a component of long-term incentive compensation. The grant date fair value is computed in accordance with the provisions of accounting standards for stock compensation. Assumptions used in the calculation of these amounts are included in Note 12 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2019.

(3) Non-Equity Incentive Plan Compensation represents amounts earned under the Short-Term Incentive Plan. The Compensation Committee approved the payout of the 2019 awards on January 28, 2020 and the awards were paid on March 6, 2020.

(4) Change in Pension Value and Nonqualified Deferred Compensation Earnings represents the net positive increase in actuarial value of the Pension Plan, Pension Restoration Benefit ("PRB") and Pension Equalization Plans ("PEP") for the respective years. These benefits have been valued using the assumptions disclosed in Note 18 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2019. Because these assumptions sometimes change between measurement dates, the change in value reflects not only the change in value due to additional benefits earned during the period and the passage of time but also reflects the change in value caused by changes in the underlying actuarial assumptions. This has created significant volatility in the last three years with a large increase in 2019 and a large decrease in 2018, primarily related to the change in discount rates used to calculate the present value of these benefits. A value of zero is shown in the Summary Compensation Table for certain officers in 2018 because the SEC does not allow a negative number to be disclosed in the table.

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

The PEP is offered through the Grandfathered Pension Equalization Plan ("Grandfathered PEP") and 2005 Pension Equalization Plan ("2005 PEP"). Mr. Emery is the only participant in the Grandfathered PEP and 2005 PEP. Messrs. Evans, Kinzley, Iverson and Buchholz are not participants in these plans; instead they receive employer contributions into a Nonqualified Deferred Compensation Plan ("NQDC"). The NQDC employer contributions are reported in the All Other Compensation column.

No Named Executive Officer received preferential or above-market earnings on nonqualified deferred compensation. The change in value attributed to each Named Executive Officer from each plan is shown in the table below.

	Year	Defined Benefit Plan	PRB	PEP	Total Change in Pension Value
David R. Emery	2019	$333,850	$2,621,203	$1,168,007	$4,123,060
	2018	($33,492)	$377,323	$179,429	$523,260
	2017	$235,056	$1,281,606	$639,268	$2,155,930
Linden R. Evans	2019	$59,664	$50,494	$—	$110,158
	2018	($19,607)	($15,074)	$—	($34,681)
	2017	$33,178	$26,453	$—	$59,631
Richard W. Kinzley	2019	$64,428	$4,203	$—	$68,631
	2018	($23,542)	($1,394)	$—	($24,936)
	2017	$34,487	$2,112	$—	$36,599
Brian G. Iverson	2019	$31,927	$—	$—	$31,927
	2018	($10,523)	$—	$—	($10,523)
	2017	$17,736	$—	$—	$17,736
Scott A. Buchholz	2019	$396,434	$359,891	$—	$756,325
	2018	($42,215)	$80,980	$—	$38,765
	2017	$226,019	$140,216	$—	$366,235

(5) All Other Compensation includes amounts allocated under the 401(k) match, defined contributions, NQDC contributions, dividends received on restricted stock and unvested restricted stock units and other personal benefits. The Other Personal Benefits column reflects the personal use of a Company vehicle, executive health, and financial planning services for each NEO. For Mr. Emery, Other Personal Benefits also includes retirement gifts, consisting primarily of a piece of art and a trip to commemorate his service to the Company, and use of the corporate aircraft to travel to outside board meetings. The aggregate incremental cost for aircraft usage in 2019 was $18,551 and the cost of the retirement gifts was $21,814.

	Year	401(k) Match	Defined Contributions	NQDC Contributions	Dividends on Restricted Stock	Other Personal Benefits	Total Other Compensation
David R. Emery	2019	$16,800	$—	$—	$35,317	$59,892	$112,009
Linden R. Evans	2019	$14,600	$22,400	$379,960	$37,260	$19,380	$473,600
Richard W. Kinzley	2019	$16,800	$20,200	$186,257	$16,220	$14,889	$254,366
Brian G. Iverson	2019	$16,800	$20,200	$98,420	$12,519	$9,051	$156,990
Scott A. Buchholz	2019	$16,800	$—	$92,879	$7,907	$16,503	$134,089

GRANTS OF PLAN BASED AWARDS IN 2019[(1)]

Name	Grant Date	Date of Compensation Committee Action	Estimated Future Payouts Under Non-Equity Incentive Plan Awards[(2)] Threshold ($)	Target ($)	Maximum ($)	Estimated Future Payouts Under Equity Incentive Plan Awards[(3)] Threshold (#)	Target (#)	Maximum (#)	All Other Stock Awards: Number of Shares of Stock or Units[(4)] (#)	Grant Date Fair Value of Stock Awards[(5)] ($)
David R. Emery										
Linden R. Evans			$375,000	$750,000	$1,500,000					
	1/29/19	1/29/19				2,881	11,524	23,048		$791,814
	2/11/19	1/29/19							10,667	$749,997
Richard W. Kinzley			$136,500	$273,000	$546,000					
	1/29/19	1/29/19				980	3,918	7,836		$269,206
	2/11/19	1/29/19							3,627	$255,014
Brian G. Iverson			$112,500	$225,000	$450,000					
	1/29/19	1/29/19				749	2,996	5,992		$205,855
	2/11/19	1/29/19							2,773	$194,970
Scott A. Buchholz			$85,000	$170,000	$340,000					
	1/29/19	1/29/19				461	1,844	3,688		$126,701
	2/11/19	1/29/19							1,707	$120,019

(1) No stock options were granted to our Named Executive Officers in 2019.

(2) The columns under "Estimated Future Payouts Under Non-Equity Incentive Plan Awards" show the range of payouts for 2019 performance under our Short-Term Incentive Plan as described in the Compensation Discussion and Analysis under the section titled "Short-Term Incentive" on page 29. If the performance criteria are met, payouts can range from 50 percent of target at the threshold level to 200 percent of target at the maximum level. The 2020 bonus payment for 2019 performance has been made based on achieving the criteria described in the Compensation Discussion and Analysis, at 107 percent of target, and is shown in the Summary Compensation Table on page 39 in the column titled "Non-Equity Incentive Plan Compensation."

(3) The columns under "Estimated Future Payouts Under Equity Incentive Plan Awards" show the range of payouts (in shares of stock) for the January 1, 2019 to December 31, 2021 performance period as described in the Compensation Discussion and Analysis under the section titled "Long-Term Incentive – Performance Shares" on page 32. If the performance criteria are met, payouts can range from 25 percent of target to 200 percent of target. If a participant retires, suffers a disability or dies during the performance period, the participant or the participant's estate is entitled to that portion of the number of performance shares as such participant would have been entitled to had he or she remained employed, prorated for the number of months served. Performance shares are forfeited if employment is terminated for any other reason. During the performance period, dividends and other distributions paid with respect to the shares of common stock accrue for the benefit of the participant and are paid out at the end of the performance period.

(4) The column "All Other Stock Awards" reflects the number of shares of restricted stock granted on February 11, 2019 under our 2015 Omnibus Incentive Plan. The restricted stock vests one-third each year over a three-year period, and automatically vests upon death, disability or a change in control. Unvested restricted stock is forfeited if employment is terminated for any other reason. Dividends are paid on the restricted stock and the dividends that were paid in 2019 are included in the column titled "All Other Compensation" in the Summary Compensation Table on page 39.

(5) The column "Grant Date Fair Value of Stock Awards" reflects the grant date fair value of each equity award computed in accordance with the provisions of accounting standards for stock compensation. The grant date fair value for the performance shares was $68.72 per share and was calculated using a Monte Carlo simulation model. Assumptions used in the calculation are included in Note 12 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2019. The grant date fair value for the restricted stock was $70.31 per share for the February 11, 2019 grant, which was the market value of our common stock on the date of grant as reported on the NYSE.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END 2019[(1)]

Name	Stock Awards			
	Number of Shares or Units of Stock That Have Not Vested[(2)] (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested[(2)] (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)
David R. Emery	17,228	$1,353,087	42,036	$3,290,605
Linden R. Evans	18,176	$1,427,543	41,425	$3,248,955
Richard W. Kinzley	7,912	$621,408	18,326	$1,436,708
Brian G. Iverson	6,107	$479,644	14,159	$1,110,066
Scott A. Buchholz	3,857	$302,929	8,945	$701,215

(1) There were no stock options outstanding at December 31, 2019 for our Named Executive Officers.

(2) Vesting dates for restricted stock and performance shares are shown in the table below. The performance shares shown with a vesting date of December 31, 2019, are the actual equivalent shares, including dividend equivalents, earned for the performance period ended December 31, 2019. On January 28, 2020, the Compensation Committee confirmed that the performance criteria were met and there would be a payout of 59 percent of target. The performance shares with a vesting date of December 31, 2020 and a vesting date of December 31, 2021 are shown at the threshold and maximum payout levels, respectively, based upon performance as of December 31, 2019.

Name	Unvested Restricted Stock		Unvested and Unearned Performance Shares	
	# of Shares	Vesting Date	# of Shares	Vesting Date
David R. Emery	5,144	02/03/20	9,888	12/31/19
	6,042	02/05/20	32,148	12/31/20
	6,042	2/5/2021(1)		
Linden R. Evans	2,166	02/03/20	4,163	12/31/19
	2,671	02/05/20	14,214	12/31/20
	3,555	02/11/20	23,048	12/31/21
	2,672	02/05/21		
	3,556	02/11/21		
	3,556	02/11/22		
Richard W. Kinzley	1,232	02/03/20	2,368	12/31/19
	1,526	02/05/20	8,122	12/31/20
	1,209	02/11/20	7,836	12/31/21
	1,527	02/05/21		
	1,209	02/11/21		
	1,209	02/11/22		
Brian G. Iverson	948	02/03/20	1,821	12/31/19
	1,193	02/05/20	6,346	12/31/20
	924	02/11/20	5,992	12/31/21
	1,193	02/05/21		
	924	02/11/21		
	925	02/11/22		
Scott A. Buchholz	623	02/03/20	1,197	12/31/19
	763	02/05/20	4,060	12/31/20
	569	02/11/20	3,688	12/31/21
	764	02/05/21		
	569	02/11/21		
	569	02/11/22		

(1) Mr. Emery's unvested restricted stock with a vesting date of February 5, 2021, will be forfeited upon his retirement.

OPTION EXERCISES AND STOCK VESTED DURING 2019[1]

Name	Stock Awards[2]	
	Number of Shares Acquired on Vesting (#)	Value Realized on Vesting ($)
David R. Emery	50,203	$3,302,667
Linden R. Evans	18,149	$1,197,059
Richard W. Kinzley	11,070	$730,294
Brian G. Iverson	9,193	$606,018
Scott A. Buchholz	7,270	$479,054

(1) There were no stock options exercised during 2019.

(2) Reflects restricted stock that vested in 2019 and performance shares for the 2016-2018 performance period. The performance share payout was approved by the Compensation Committee on January 29, 2019 and paid out on February 5, 2019.

PENSION BENEFITS FOR 2019

Several years ago, we adopted a defined contribution plan design as our primary retirement plan and amended our Pension Plan and Nonqualified Pension Plans for all eligible employees to incorporate a partial freeze in which the accrual of benefits ceased for certain participants while other participants were allowed an election to continue to accrue benefits. Employees eligible to elect continued participation were those employees who were at least 45 years old and had at least 10 years of eligible service with us as of January 1, 2010. Messrs. Emery and Buchholz were our only Named Executive Officers who met the age and service requirement and continue to accrue benefits under the Pension Plan and the Pension Restoration Plan. Benefits under the Pension Plan and Pension Restoration Plan were frozen for Messrs. Evans, Kinzley and Iverson. In addition, Mr. Emery received supplemental pension benefits under the Grandfathered Pension Equalization Plan, which was frozen effective December 31, 2004, and the 2005 Pension Equalization Plan. None of our Named Executive Officers received any pension benefit payments during the fiscal year ended December 31, 2019.

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

Name	Plan Name	Number of Years of Credited Service(1) (#)	Present Value of Accumulated Benefit(2) ($)
David R. Emery	Pension Plan	30.33	$1,449,354
	Pension Restoration Benefit	30.33	$9,675,816
	Grandfathered Pension Equalization Plan	24.00	$954,414
	2005 Pension Equalization Plan	24.00	$4,771,612
Linden R. Evans	Pension Plan	8.58	$315,624
	Pension Restoration Benefit	8.58	$255,319
Richard W. Kinzley	Pension Plan	10.50	$289,883
	Pension Restoration Benefit	10.50	$18,063
Brian G. Iverson	Pension Plan	5.83	$168,237
Scott A. Buchholz	Pension Plan	40.17	$1,841,227
	Pension Restoration Plan	40.17	$1,579,132

(1) The number of years of credited service represents the number of years used in determining the benefit for each plan. The Pension Equalization Plans are not directly tied to service but rather the number of years of participation in the plan.

(2) The present value of accumulated benefits was calculated assuming the participants will work until retirement, benefits commence at age 62 and using the discount rate, mortality rate and assumed payment form assumptions consistent with those disclosed in Note 18 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2019.

DEFINED BENEFIT PENSION PLAN

Our Pension Plan is a qualified pension plan in which all of our Named Executive Officers are included. As discussed above, several years ago we amended our Pension Plan to incorporate a partial freeze in which the accrual of benefits ceased for certain participants while other participants were allowed an election to continue to accrue benefits. Messrs. Emery and Buchholz were the only Named Executive Officers who met the age and service requirement and elected to continue with the existing plan.

The Pension Plan provides benefits at retirement based on length of employment service and average compensation levels during the highest five consecutive years of the last ten years of service. For purposes of the benefit calculation, earnings include wages and other cash compensation received from us, including any bonus, commission, unused paid time off or incentive compensation. It also includes any elective before-tax contributions made by the employee to a Company-sponsored cafeteria plan or 401(k) plan. However, it does not include any expense reimbursements, taxable fringe benefits, moving expenses or moving/relocation allowances, nonqualified deferred compensation, non-cash incentives, stock options and any payments of long-term incentive compensation such as restricted stock or payments under performance share plans. The Internal Revenue Code places maximum limitations on the amount of compensation that may be recognized when determining benefits of qualified pension plans. In 2019, the maximum amount of compensation that could be recognized when determining compensation was $280,000 (called "covered compensation"). Our employees do not contribute to the plan. The amount of the annual contribution by us to the plan is based on an actuarial determination.

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

(a) Credited Service after January 31, 2000

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

Plus

(b) Credited Service before January 31, 2000

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

Pension benefits are not reduced for social security benefits. The Internal Revenue Code places maximum limitations on annual benefit amounts that can be paid under qualified pension plans. In 2019, the maximum benefit payable under qualified pension plans was $225,000. Accrued benefits become 100 percent vested after an employee completes five years of service.

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

PENSION EQUALIZATION PLANS AND PENSION RESTORATION BENEFIT

We also have a Grandfathered Pension Equalization Plan, a 2005 Pension Equalization Plan and a Pension Restoration Benefit. These are nonqualified supplemental plans, in which benefits are not tax deductible until paid. The plans are designed to provide the higher paid executive employee a retirement benefit which, when added to social security benefits and the pension to be received under the Pension Plan, will approximate retirement benefits being paid by other employers to their employees in similar executive positions. The employee's pension from the qualified Pension Plan is limited by the Internal Revenue Code. The 2019 pension limit was set at $225,000 annually and the compensation taken into account in determining contributions and benefits could not exceed $280,000 and could not include nonqualified deferred compensation. The amount of deferred compensation paid under nonqualified plans is not subject to these limits.

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

Grandfathered Pension Equalization Plan and 2005 Pension Equalization Plan. The Grandfathered Pension Equalization Plan provides the pension equalization benefits to each participant who had earned and vested benefits before January 1, 2005, and is not subject to the provisions of Section 409A of the Internal Revenue Code. The 2005 Pension Equalization Plan provides the pension equalization benefits to each participant that were earned and vested on or after January 1, 2005, and is subject to the provisions of Section 409A.

These plans have been frozen to new participants since 2002. Mr. Emery is a fully vested participant in the Grandfathered and 2005 Pension Equalization Plans. Messrs. Evans, Kinzley, Iverson and Buchholz are not participants in these plans.

The annual benefit for Mr. Emery is 30 percent of his average earnings multiplied by the vesting percentage. Average earnings are normally an employee's average earnings for the five highest consecutive full years of employment during the ten full years of employment immediately preceding the year of calculation. The annual benefit is paid on a monthly basis for 15 years and, if deceased, to the employee's designated beneficiary or estate, commencing at the earliest of death or when the employee is both retired and 62 years of age or more. A participant with vested benefits who is 55 years of age or older and who is no longer our employee may elect to be paid benefits beginning at age 55 or older, subject to a discount, ranging from 60.3 percent of the benefit payable at age 55 to 93 percent of the benefit payable at age 61.

Pension Restoration Benefit. In the event that at the time of a participant's retirement, the participant's salary level exceeds the qualified Pension Plan annual compensation limitation ($280,000 in 2019) or includes nonqualified deferred compensation, then the participant will receive an additional benefit, called a "Pension Restoration Benefit," which is measured by the difference between (i) the monthly benefit that would have been provided to the participant under the Pension Plan as if there were no annual compensation limitation and no exclusion on nonqualified deferred compensation, and (ii) the monthly benefit to be provided to the participant under the Pension Plan. The Pension Restoration Benefit applies to all of the Named Executive Officers that have a pension benefit, with the exception of Mr. Iverson.

NONQUALIFIED DEFERRED COMPENSATION FOR 2019

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

A summary of the activity in the plan and the aggregate balance as of December 31, 2019 for our Named Executive Officers is shown in the following table. Our Named Executive Officers received no withdrawals or distributions from the plan in 2019.

Name	Executive Contributions	Company Contributions in Last Fiscal Year(1)	Aggregate Earnings in Last Fiscal Year(2)	Aggregate Balance at Last Fiscal Year End(3)
David R. Emery	$—	$—	$—	$—
Linden R. Evans	$—	$379,960	$711,987	$3,543,643
Richard W. Kinzley	$—	$186,257	$277,096	$1,549,260
Brian G. Iverson	$—	$98,420	$120,298	$624,021
Scott A. Buchholz	$—	$92,879	$146,375	$980,520

(1) Our contributions represent non-elective Supplemental Matching and Retirement Contributions and Supplemental Target Contributions (defined in the paragraph below) and are included in the All Other Compensation column of the Summary Compensation Table. The value attributed from each contribution type to each Named Executive Officer in 2019 is shown in the table below:

Name	Supplemental Matching Contribution	Supplemental Retirement Contribution	Supplemental Target Contribution	Total Company Contributions
David R. Emery	$—	$—	$—	$—
Linden R. Evans	$57,169	$76,226	$246,565	$379,960
Richard W. Kinzley	$26,144	$34,859	$125,254	$186,257
Brian G. Iverson	$20,733	$27,644	$50,043	$98,420
Scott A. Buchholz	$16,104	$—	$76,775	$92,879

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

(3) Messrs. Evans’, Kinzley’s, Iverson’s and Buchholz’s aggregate balances at December 31, 2019 include $911,817, $498,358, $244,485, and $252,989, respectively, which are included in the Summary Compensation Table as 2019, 2018 and 2017 compensation.

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

The deferrals are deposited into hypothetical investment accounts where the participants may direct the investment of the deferrals as allowed by the plan. The investment options are the same as those offered to all employees in the 401(k) Retirement Savings Plan except for a fixed rate option, which was set at 3.91 percent in 2019. Investment earnings are credited to the participants' accounts. Upon retirement, we will distribute the account balance to the participant according to the distribution election filed with the Compensation Committee. The participants may elect either a lump sum payment to be paid within 30 days of retirement (requires a six-month deferral for benefits not vested as of December 31, 2004), or annual or monthly installments over a period of years designated by the participant, but not to exceed 10 years. As of January 1, 2020, Messrs. Evans, Kinzley, Iverson and Buchholz are 100 percent vested in the plan.

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

The following table describes the potential payments and benefits under our compensation and benefit plans and arrangements to which our Named Executive Officers would be entitled upon termination of employment. Except for (i) certain terminations following a change in control ("CIC"), as described below, (ii) pro-rata payout of incentive compensation and the acceleration of vesting of equity awards upon retirement, death or disability, and (iii) certain pension and nonqualified deferred compensation arrangements described under Pension Benefits for 2019 and Nonqualified Deferred Compensation for 2019 above, there are no agreements, arrangements or plans that entitle the Named Executive Officers to severance, perquisites, or other enhanced benefits upon termination of their employment. Any agreements to provide other payments or benefits to a terminating executive officer would be in the discretion of the Compensation Committee.

The amounts shown below assume that such termination was effective as of December 31, 2019, and thus includes estimates of the amounts that would be paid out to our Named Executive Officers upon their termination. The table does not include amounts such as base salary, short-term incentives and stock awards that the Named Executive Officers earned due to employment through December 31, 2019 and distributions of vested benefits such as those described under Pension Benefits for 2019 and Nonqualified Deferred Compensation for 2019. The table also does not include a value for outplacement services because this would be a de minimis amount. The actual amounts to be paid can only be determined at the time of such Named Executive Officer's separation from us.

	Cash Severance Payment	Incremental Retirement Benefit (present value)(2)	Continuation of Medical/ Welfare Benefits (present value)(3)	Acceleration of Equity Awards(4)	Total Benefits
Linden R. Evans					
• Retirement	—	—	—	$886,207	$886,207
• Death or disability	—	—	—	$2,293,751	$2,293,751
• Involuntary termination	—	—	—	—	—
• CIC	—	—	—	$1,709,190	$1,709,190
• Involuntary or good reason termination after CIC(1)	$4,485,000	$1,530,000	$78,900	$1,709,190	$7,803,090
Richard W. Kinzley					
• Retirement	—	—	—	$433,480	$433,480
• Death or disability	—	—	—	$1,054,889	$1,054,889
• Involuntary termination	—	—	—	—	—
• CIC	—	—	—	$781,598	$781,598
• Involuntary or good reason termination after CIC(1)	$1,386,000	$436,590	$80,700	$781,598	$2,684,888
Brian G. Iverson					
• Retirement	—	—	—	$337,189	$337,189
• Death or disability	—	—	—	$816,832	$816,832
• Involuntary termination	—	—	—	—	—
• CIC	—	—	—	$602,856	$602,856
• Involuntary or good reason termination after CIC(1)	$1,200,000	$264,000	$47,200	$602,856	$2,114,056
Scott A. Buchholz					
• Retirement	—	—	—	$214,047	$214,047
• Death or disability	—	—	—	$516,976	$516,976
• Involuntary termination	—	—	—	—	—
• CIC	—	—	—	$383,901	$383,901
• Involuntary or good reason termination after CIC(1)	$1,020,000	$204,000	$52,100	$383,901	$1,660,001

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

(2) Assumes that in the event of a change in control, Mr. Evans will receive an additional three years of credited and vesting service and the other Named Executive Officers will receive an additional two years of credited and vesting service towards the benefit accrual under their applicable retirement plans. For Messrs. Kinzley, Evans, Iverson and Buchholz, this would be the Retirement Contributions and Nonqualified Deferred Compensation contributions. In addition, Mr. Buchholz would also have a Pension Restoration Contribution. The benefits will immediately vest and payments will commence at the earliest eligible date unless the executive has elected a later date for the nonqualified plans. This is age 55 for Mr. Kinzley. Because Messrs. Evans, Iverson and Buchholz are age 55 or older, they are already retiree eligible.

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

(4) In the event of death or disability, the acceleration of equity awards represents the acceleration of unvested restricted stock and the assumed payout of the pro-rata share of the performance shares for the January 1, 2018 to December 31, 2020 and January 1, 2019 to December 31, 2021 performance periods. In the event of retirement, all unvested restricted stock is

forfeited and the acceleration of equity awards represents only the pro-rata share of the performance shares. We assumed a 156 percent payout of the performance shares for the January 1, 2018 to December 31, 2020 performance period and a 87 percent payout of target for the January 1, 2019 to December 31, 2021 performance period based on our Monte Carlo valuations at December 31, 2019.

In the event of a change in control or an involuntary or good reason termination after a change in control, the acceleration of equity awards represents the acceleration of unvested restricted stock and the payout of the pro-rata share of the performance shares calculated as if the performance period ended on December 31, 2019 for the January 1, 2018 to December 31, 2020 and January 1, 2019 to December 31, 2021 performance periods.

The valuation of the restricted stock was based upon the closing price of our common stock on December 31, 2019, and the valuation of the performance shares was based on the average closing price of our common stock for the last 20 trading days of 2019. Actual amounts to be paid out at the time of separation from us may vary significantly based upon the market value of our common stock at that time.

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

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

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

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

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

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

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

A change in control is defined in the agreements as:

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

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

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

In connection with Mr. Emery's upcoming retirement as Executive Chairman, the Compensation Committee did not renew Mr. Emery's prior change in control agreement beyond its expiration on November 15, 2019.

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

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

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

- all accrued compensation and a pro-rata bonus (the same as Mr. Evans or Mr. Evans' beneficiaries would receive in the event of death or disability discussed above);
- severance pay equal to 2.99 times Mr. Evans' severance compensation defined as his base salary and short-term incentive target on the date of the change in control; provided that if Mr. Evans has attained the age of 62 on the termination date, the severance payment will be adjusted for the ratio of the number of days remaining to his 65th birthday to 1,095 days;
- continuation of employee welfare benefits for three years following the termination date unless Mr. Evans becomes covered under the health insurance coverage of a subsequent employer which does not contain any exclusion or limitation with respect to any preexisting condition of Mr. Evans or his eligible dependents;
- following the three-year period, Mr. Evans may elect to receive coverage under the employee welfare plans of the successor entity at his then-current level of benefits (or reduced coverage at his election) by paying the premiums charged to regular full-time employees for such coverage, and is eligible to continue receiving such coverage through the date of his retirement;
- three additional years of service and age will be credited to Mr. Evans' retiree medical savings account and the account balance will become fully vested and he is eligible to use the account balance to offset retiree medical premiums at the later of age 55 or the end of the three year continuation period;
- three years of additional credited service under the 2005 Pension Equalization Plan, Pension Restoration Plan and Pension Plan; and
- outplacement assistance services for up to six months.

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

- all accrued compensation and a pro-rata bonus (the same as the NEO or the NEO's beneficiaries would receive in the event of death or disability discussed above);
- severance pay equal to two times the NEO's severance compensation defined as the NEO's base salary and short-term incentive target on the date of the change in control; provided that if the NEO has attained the age of 63 on the termination date, the severance payment shall be adjusted for the ratio of the number of days remaining to the NEO's 65th birthday to 730 days;

- continuation of employee welfare benefits for two years following the termination date unless the NEO becomes covered under the health insurance coverage of a subsequent employer which does not contain any exclusion or limitation with respect to any preexisting condition of the NEO or the NEO's eligible dependents;
- following the two-year period, the NEO may elect to receive coverage under the employee welfare plans of the successor entity at his then-current level of benefits (or reduced coverage at the NEO's election) by paying the premiums charged to regular full-time employees for such coverage, and is eligible to continue receiving such coverage through the date of his retirement;
- two additional years of service and age will be credited to the NEO's retiree medical savings account and the account balance will become fully vested and the NEO is eligible to use the account balance to offset retiree medical premiums at the later of age 55 or the end of the two year continuation period;
- two years of additional credited service under the executives' applicable retirement plans; and
- outplacement assistance services for up to six months.

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

PAY RATIO FOR 2019

We are providing the following information about the relationship of the annual total compensation of our employees and the annual total compensation of Mr. Linden Evans, our Chief Executive Officer in 2019.

Based on the information below for the fiscal year 2019 and calculated in a manner consistent with Item 402(u) of Regulation S-K, we reasonably estimate that the ratio of our CEO's annual total compensation to the annual total compensation of our median employee was 39:1.

Name	Year	Salary	Stock Awards	Non-Equity Incentive Plan Compensation	Change in Pension Value(2)	All Other Compensation(3)	Total
Linden R. Evans	2019	$713,333	$1,541,811	$800,400	$110,158	$473,600	$3,639,302
Median Employee (1)	2019	$80,684	$—	$7,319	$—	$5,626	$93,629

(1) We identified our median employee based on the year-to-date total cash compensation actually paid as of October 3, 2017 to all of our employees, other than our CEO, who were employed on October 3, 2017. There has been no change in employee population or employee compensation that we reasonably believe would result in a significant change in our pay ratio disclosure. Accordingly, the Company utilized the same employee as the median employee for 2019.

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

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

PROPOSAL 3	ADVISORY VOTE ON OUR EXECUTIVE COMPENSATION

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

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

This vote is non-binding. The Board of Directors and the Compensation Committee expect to consider the outcome of the vote when considering future executive compensation decisions to the extent they can determine the cause or causes of any significant negative voting results. At our 2019 annual meeting, shareholders owning 97 percent of the shares voted to approve our executive compensation.

As described at length in the Compensation Discussion and Analysis section of this proxy statement, we believe our executive compensation program is reasonable, competitive and strongly focused on pay for performance. The compensation of our Named Executive Officers varies depending upon the achievement of pre-established performance goals, both individual and corporate. Our short-term incentive is tied to earnings per share and safety performance targets that reward our executives when they deliver targeted financial and safety results. Our long-term incentives are tied to market performance with 50 percent delivered in restricted stock and 50 percent delivered in performance shares. Entitlement to the performance shares is based on our total shareholder return over a three-year performance period compared to our Performance Peer Group. Through stock ownership guidelines, equity incentives and clawback provisions, we align the interests of our executives with those of our shareholders and our long-term interests. Our executive compensation policies have enabled us to attract and retain talented and experienced senior executives who can drive financial and strategic growth objectives that are intended to enhance shareholder value. We believe that the 2019 compensation of our Named Executive Officers was appropriate and aligned with our 2019 results and positions us for long-term growth.

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

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

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

TRANSACTION OF OTHER BUSINESS

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

SHAREHOLDER PROPOSALS FOR 2021 ANNUAL MEETING

Shareholder proposals intended to be presented at our 2021 annual meeting of shareholders and considered for inclusion in our proxy materials must be received by our Corporate Secretary in writing at our executive offices at 7001 Mount Rushmore Road, P.O. Box 1400, Rapid City, South Dakota 57709, on or prior to November 13, 2020. Any proposal submitted must be in compliance with Rule 14a-8 of Regulation 14A of the Securities and Exchange Commission.

Additionally, a shareholder may submit a proposal or director nominee for consideration at our 2021 annual meeting of shareholders, but not for inclusion of the proposal or director nominee in our proxy materials, if the shareholder gives timely written notice of such proposal in accordance with Article I, Section 9 of our Bylaws. In general, Article I, Section 9 provides that, to be timely, a shareholder's notice must be delivered to our Corporate Secretary in writing not less than 90 days nor more than 120 days prior to the anniversary date of the immediately preceding annual meeting of shareholders.

Our 2020 annual meeting is scheduled for April 28, 2020. Ninety days prior to the first anniversary of this date will be January 28, 2021, and 120 days prior to the first anniversary of this date will be December 29, 2020. For business to be properly requested by the shareholder to be brought before the 2021 annual meeting of shareholders, the shareholder must comply with all of the requirements of Article I, Section 9 of our Bylaws, not just the timeliness requirements set forth above.

SHARED ADDRESS SHAREHOLDERS

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

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

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

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

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

ANNUAL REPORT ON FORM 10-K

A copy of our Annual Report on Form 10-K (excluding exhibits) for the year ended December 31, 2019, which is required to be filed with the Securities and Exchange Commission, will be made available to shareholders to whom this proxy statement is mailed, without charge, upon written or oral request to Shareholder Relations, Black Hills Corporation, 7001 Mount Rushmore Road, P.O. Box 1400, Rapid City, SD 57709, Telephone Number: (605) 721-1700. Our Annual Report on Form 10-K also may be accessed through our website at www.blackhillscorp.com.

IMPORTANT NOTICE REGARDING THE AVAILABILITY OF PROXY MATERIALS FOR THE SHAREHOLDER MEETING TO BE HELD ON APRIL 28, 2020

Shareholders may view this proxy statement, our form of proxy and our 2019 Annual Report to Shareholders over the Internet by accessing our website at www.blackhillscorp.com. Information on our website does not constitute a part of this proxy statement.

By Order of the Board of Directors,

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

Dated: March 13, 2020

APPENDIX A RECONCILIATION OF NON-GAAP FINANCIAL MEASURES

	Year Ended	
	Dec. 31, 2019	Dec. 31, 2018
EPS from continuing operations (GAAP)	$ 3.28	$ 4.78
Adjustments:		
Impairment of investment	0.32	—
Legal restructuring - income tax benefits	—	(1.31)
Tax reform	—	0.07
Total adjustments	0.32	(1.24)
Tax on adjustments:		
Impairment of investment	(0.07)	—
Total adjustments, net of tax	0.25	(1.24)
EPS from continuing operations, as adjusted (Non-GAAP)	$ 3.53	$ 3.54

USE OF NON-GAAP FINANCIAL MEASURE

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

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

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2019

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, including area code (605) 721-1700

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

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

Indicate 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 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, 2019, was $4,727,278,183

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, 2020
Common stock, $1.00 par value	61,475,403 shares

Documents Incorporated by Reference
Portions of the registrant's Definitive Proxy Statement being prepared for the solicitation of proxies in connection with the 2020 Annual Meeting of Stockholders to be held on April 28, 2020, are incorporated by reference in Part III of this Form 10-K.

TABLE OF CONTENTS

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.
Basin Electric	Basin Electric Power Cooperative
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	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	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.
CAPP	Customer Appliance Protection Plan, which provides appliance repair services to residential natural gas customers through on-going monthly service agreements. The consolidation of the existing Service Guard and CAPP plans into the revamped Service Guard Comfort Plan is currently underway across our service territories.
CFTC	United States Commodity Futures Trading Commission
Cheyenne Prairie	132 MW natural-gas fired generating facility jointly owned by South Dakota Electric and Wyoming Electric in Cheyenne, Wyoming. Cheyenne Prairie was placed into commercial service on October 1, 2014.
Choice Gas Program	Regulator approved programs in Wyoming and Nebraska that allow certain utility customers to select their natural gas commodity supplier, providing the unbundling of the commodity service from the distribution delivery service.
City of Gillette	Gillette, Wyoming
City of Cheyenne	Cheyenne, 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 joint transmission system we participate in with Basin Electric 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	Wind project near Cheyenne, Wyoming, that will be a 52.5 MW wind farm jointly owned by South Dakota Electric and Wyoming Electric and will serve as the dedicated wind energy supply to the Renewable Ready program.
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
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DSM	Demand Side Management
DRSPP	Dividend Reinvestment and Stock Purchase Plan
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 -- adjustments that allow 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.
EIA	Environmental Improvement Adjustment -- annual adjustment mechanism that allows us to recover from customers eligible investments in, and expense related to, new environmental measures.
EPA	United States Environmental Protection Agency
Equity Unit	Each Equity Unit has 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 RSNs due 2028. 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

FDIC	Federal Deposit Insurance Corporation
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 -- adjustments that allow us to pass the prudently-incurred cost of gas and certain services through to customers.
GHG	Greenhouse gases
Global Settlement	Settlement with a utilities 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.
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
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).
NERC	North American Electric Reliability Corporation
NO_x	Nitrogen oxide
NOL	Net operating loss
NPSC	Nebraska Public Service Commission
NYSE	New York Stock Exchange
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 -- 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 -- 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	60 MW wind generating project owned by Colorado Electric, placed in service on November 7, 2016 and adjacent to Busch Ranch I.
PPA	Power Purchase Agreement
PRPA	Platte River Power Authority
PSA	Power Sales Agreement
PSCo	Public Service Company of Colorado
Pueblo Airport Generation	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
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.
Renewable Ready	Voluntary renewable energy subscription program for large commercial, industrial and governmental agency customers. The Corriedale wind project will provide 52.5 MW of energy for Renewable Ready subscribers in Wyoming and western South Dakota.
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).
RSNs	Remarketable junior subordinated notes, issued on November 23, 2015 and retired on August 17, 2018.
SCADA	Supervisory control and data acquisition
SDPUC	South Dakota Public Utilities Commission
SEC	United States Securities and Exchange Commission
Service Guard	Home appliance repair product offering for both natural gas and electric residential customers through on-going monthly service agreements. The consolidation of the existing Service Guard and CAPP plans into the revamped Service Guard Comfort Plan is currently underway across our service territories.
Service Guard Comfort Plan	New plan that will consolidate Service Guard and CAPP and provide similar services.
Silver Sage	Silver Sage Windpower, LLC, owned by Duke Energy Generation Services
SO_2	Sulfur dioxide
S&P	Standard & Poor’s, a division of The McGraw-Hill Companies, Inc.
SPP	Southwest Power Pool, Inc. which oversees the bulk electric grid and wholesale power market in the central United States
SourceGas Transaction	On February 12, 2016, Black Hills Utility Holdings acquired SourceGas pursuant to a purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, which included the assumption of $760 million in debt at closing.
South Dakota Electric	Black Hills Power, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation, providing electric service to customers in Montana, South Dakota and Wyoming (doing business as Black Hills Energy).
SSIR	System Safety and Integrity Rider
System Peak Demand	Represents the highest point of retail customer usage for a single hour.
TCA	Transmission Cost Adjustment -- 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 within Black Hills Corporation 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-owner gas infrastructure facilities, typically through one-time contracts.
TFA	Transmission Facility Adjustment -- annual adjustment mechanism that allows us to recover charges for qualifying new and modified transmission facilities from customers.
VEBA	Voluntary Employee Benefit Association
VIE	Variable Interest Entity
WDEQ	Wyoming Department of Environmental Quality
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 (doing business as Black Hills Energy)
Wyoming Electric	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation, providing electric service to customers in the Cheyenne, Wyoming area (doing business as Black Hills Energy).
Wyoming Gas	Black Hills Wyoming Gas, LLC, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Wyoming (doing business as Black Hills Energy).

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, it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements in this Form 10-K, including statements contained within Item 1A - Risk Factors.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

History and Organization

Black Hills Corporation, a South Dakota corporation (together with its subsidiaries, referred to herein as the "Company," "we," "us" or "our"), is a customer-focused, growth-oriented utility company headquartered in Rapid City, South Dakota. Our predecessor company, Black Hills Power and Light Company, was incorporated and began providing electric utility service in 1941. It was formed through the purchase and combination of several existing electric utilities and related assets, some of which had served customers in the Black Hills region since 1883. In 1956, with the purchase of the WRDC mine, we began producing and selling energy through non-regulated businesses.

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 214,000 electric utility customers in Colorado, Montana, South Dakota and Wyoming. Our Electric Utilities own 939 MW of generation and 8,892 miles of electric transmission and distribution lines.

Our Gas Utilities segment serves approximately 1,066,000 natural gas utility customers in Arkansas, Colorado, Iowa, Kansas, Nebraska, and Wyoming. Our Gas Utilities own and operate approximately 4,775 miles of intrastate gas transmission pipelines and 41,210 miles of gas distribution mains and service lines, seven natural gas storage sites, nearly 49,000 horsepower of compression and over 500 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 it primarily under long-term contracts to adjacent mine-mouth electric generation facilities owned by our Electric Utilities and Power Generation businesses.

Electric Utilities Segment

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 distribution systems. Additionally, we sell excess power to other utilities and marketing companies, including our affiliates. We also provide non-regulated services through our Tech Services product lines.

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)					
	2019		2018		2017	
	Summer	Winter	Summer	Winter	Summer	Winter
Colorado Electric [(a)]	422	297	413	313	398	299
South Dakota Electric	335	320	355	314	370	310
Wyoming Electric [(b)]	265	247	254	238	249	230

(a) The Colorado Electric July 2019 summer peak load of 422 surpassed previous summer peak record load of 413 set in June 2018. The October 2018 winter peak load of 313 surpassed previous winter peak load of 310 set in February 2011.
(b) The Wyoming Electric July 2019 summer peak load of 265 surpassed previous summer peak record load of 254 set in July 2018. The December 2019 winter peak load of 247 surpassed the previous winter peak record load of 238 set in December 2018.

Regulated Power Plants. As of December 31, 2019, our Electric Utilities' ownership interests in electric generating plants were as follows:

Unit	Fuel Type	Location	Ownership Interest %	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 [(c)]	Gas	Cheyenne, Wyoming	58%	55.0	2014
Wygen III [(d)]	Coal	Gillette, Wyoming	52%	57.2	2010
Neil Simpson II	Coal	Gillette, Wyoming	100%	90.0	1995
Wyodak Plant [(e)]	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 [(c)]	Gas	Cheyenne, Wyoming	42%	40.0	2014
Cheyenne Prairie CT [(c)]	Gas	Cheyenne, Wyoming	100%	37.0	2014
Wygen II	Coal	Gillette, Wyoming	100%	95.0	2008
Total MW Capacity				939.1	

(a) Busch Ranch I is operated by Colorado Electric. In 2013, the facility was awarded a one-time cash grant in lieu of ITCs under the Section 1603 program created under the American Recovery and Reinvestment Act. Black Hills Electric Generation owns the remaining 50% interest in the wind farm. Colorado Electric has a PPA with Black Hills Electric Generation for its share of power from the wind farm.

(b) The Peak View facility qualifies for PTCs at $25/MWh under IRC 45 during the 10-year period beginning on the date the facility was originally placed in service. The PTCs for this facility flow back to customers through a rider mechanism as a reduction to Colorado Electric's margins. Peak View was placed in service in November 2016.

(c) Cheyenne Prairie serves the utility customers of South Dakota Electric and Wyoming Electric. The facility includes one simple-cycle, 37 MW combustion turbine that is wholly-owned by Wyoming Electric and one combined-cycle, 95 MW unit that is jointly-owned by Wyoming Electric (40 MW) and South Dakota Electric (55 MW).

(d) Wygen III, a 110 MW mine-mouth coal-fired power plant, is operated by South Dakota Electric. South Dakota Electric owns 52% of the power plant, MDU owns 25% and the City of Gillette owns the remaining 23% interest. Our adjacent WRDC mine supplies all of the fuel for the plant.

(e) Wyodak Plant, a 362 MW mine-mouth coal-fired power plant, is owned 80% by PacifiCorp and 20% by South Dakota Electric. This baseload plant is operated by PacifiCorp and our WRDC mine supplies all of the fuel for the plant.

The Electric Utilities' annual 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 was as follows:

Fuel Source (dollars per MWh)	2019	2018	2017
Coal	$ 11.46	$ 11.10	$ 10.95
Natural Gas	$ 25.92	$ 33.42	$ 34.05
Diesel Oil [(a)]	$ 209.86	$ 329.27	$ 210.11
Total Weighted Average Fuel Cost	$ 13.86	$ 13.53	$ 12.80
Purchased Power - Coal, Gas and Oil	$ 43.73	$ 45.62	$ 45.63
Purchased Power - Renewable Sources	$ 48.61	$ 54.31	$ 53.08

(a) Included in the Price per MWh for Diesel Oil are unit start-up costs. The diesel-fueled generating units are generally used as supplemental peaking units and the cost per MWh is reflective of how often the units are started and how long the units are run.

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	2019	2018	2017
Coal	30%	32%	32%
Gas, Oil and Wind	12	10	8
Total Generated	42	42	40
Purchased [(a)]	58	58	60
Total	100%	100%	100%

(a) Wind represents approximately 6%, 6% and 6% of our purchased power in 2019, 2018, and 2017, respectively.

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 19 of the Notes to the 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 own an electric transmission system, referred to as the Common Use System, with Basin Electric and Powder River Energy Corporation.

At December 31, 2019, our Electric Utilities owned the electric transmission and distribution lines shown below:

Utility	State	Transmission (in Line Miles)	Distribution (in Line Miles)
Colorado Electric	Colorado	598	3,120
South Dakota Electric	South Dakota, Wyoming	1,219	2,557
South Dakota Electric - Jointly Owned [(a)]	South Dakota, Wyoming	43	—
Wyoming Electric	Wyoming	49	1,306
		1,909	6,983

(a) 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. 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. See Note 4 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

Material contracts are disclosed in Note 19 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K. Additional contracts disclosed below are also key to allowing us to serve our customer load:

Colorado Electric is party to a joint dispatch agreement with PSCo and PRPA. This FERC-approved agreement, effective in 2017, is structured to allow PSCo, as administrator, to receive load and generation bid information for all three parties and, on an intra-hour basis, serve the combined utility load utilizing the combined bid generating resources on a least-cost basis. In other words, if one party has excess generation at a lower cost than another party's generation, the administrator will increase dispatch of the lower-cost generation and decrease dispatch of the higher-cost generation. This results in lower energy costs to customers through more efficient dispatch of low-cost generating resources. Under the agreement, Colorado Electric retains the ability to participate or not participate in the joint dispatch at its discretion.

South Dakota Electric has firm network transmission access to deliver power on PacifiCorp's system to Sheridan, Wyoming, to serve our power sales contract with MDU through December 31, 2023, with the right to renew pursuant to the terms of PacifiCorp's transmission tariff.

Wyoming Electric has a firm network transmission agreement with Western Area Power Administration's Loveland Area Project that allows us to serve our existing load in Cheyenne, Wyoming.

Operating Agreements. Our Electric Utilities have the following material operating agreements:

- Shared Services Agreements -
  - South Dakota Electric, Wyoming Electric, and Black Hills Wyoming are parties to a shared facilities agreement, whereby each entity is charged for the use of assets located at the Gillette, Wyoming energy complex by the affiliate entity.
  - Black Hills Colorado IPP and Colorado Electric are also parties to a facility fee agreement, whereby Colorado Electric charges Black Hills Colorado IPP for the use of Colorado Electric assets.
  - South Dakota Electric and BHSC are parties to a shared facilities agreement, whereby BHSC is charged for the use of the Horizon Point facility that is owned by South Dakota Electric and BHSC provides certain operations and maintenance services at the facility.
  - South Dakota Electric and Wyoming Electric receive certain staffing and management services from BHSC for Cheyenne Prairie.
- Jointly Owned Facilities agreements are discussed in Note 4 of the Notes to the 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, demand is often greater in the summer and winter months for cooling and heating, respectively.

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 independent power producers for the right to provide electric energy and capacity for Colorado Electric when resource plans require additional resources.

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

Subsidiary	Jurisdiction	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Authorized Capital Structure Debt/Equity	Authorized Rate Base (in millions)	Effective Date	Additional Tariffed Mechanisms	Percentage of Power Marketing Profit Shared with Customers
Colorado Electric	CO	9.37%	7.43%	47.6%/52.4%	$539.6	1/2017	ECA, TCA, PCCA, Energy Efficiency Cost Recovery/DSM, Renewable Energy Standard Adjustment	90%
	CO	9.37%	6.02%	67.3%/32.7%	$57.9	1/2017	Clean Air Clean Jobs Act Adjustment Rider	N/A
South Dakota Electric	WY	9.9%	8.13%	46.7%/53.3%	$46.8	10/2014	ECA	65%
	SD	Global Settlement	7.76%	Global Settlement	$543.9	10/2014	ECA, Energy Efficiency Cost Recovery/DSM, TFA, EIA	70%
	FERC	10.8%	8.76%	43%/57%	$138.4 [(a)]	2/2009	FERC Transmission Tariff	N/A
Wyoming Electric	WY	9.9%	7.98%	46%/54%	$376.8	10/2014	PCA, Energy Efficiency Cost Recovery/DSM, Rate Base Recovery on Acquisition Adjustment	N/A
	FERC	10.6%	8.51%	46%/54%	$31.5	5/2014	FERC Transmission Tariff	N/A

(a) Includes $121.3 million in 2019 rate base for the Common Use System formula rate that is updated annually and $17.1 million in rate base for the DC 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. In all states, subject to thresholds noted below, we have cost adjustment mechanisms for our Electric Utilities that allow us to pass the prudently-incurred cost of fuel and purchased power through to customers. These mechanisms allow the utility operating in that state to collect, or refund the difference between the cost of commodities and certain services embedded in our base rates and the actual cost of the commodities and certain services without filing a general rate review. In addition, some states allow for recovery of new capital investment placed in service between base rate reviews through approved rider tariffs. These tariffs allow the utility a return on the investment.

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

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

See Note 13 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for information regarding current electric rate activity.

The significant mechanisms we have in place include the following by utility:

Colorado Electric has:

- A quarterly ECA rider that allows us to recover forecasted increases or decreases in purchased energy and fuel costs, including the recovery for amounts payable to others for the transmission of the utility's electricity over transmission facilities owned by others, and the sharing of off-system sales margins, less certain operating costs (customer receives 90%). The ECA provides for not only direct recovery, but also for the issuance of credits for decreases in purchased energy, fuel costs and eligible energy resources.

- An annual TCA rider that includes nine months of actual transmission investment and three months of forecasted investment, with an annual true-up mechanism.

- A Clean Air Clean Jobs Act Adjustment rider rate that collects the authorized revenue requirement for the 40 MW combustion turbine placed in service on December 31, 2016 with rates effective January 1, 2017.

- A Renewable Energy Standard Adjustment rider that is specifically designed for meeting the requirements of Colorado’s renewable energy standard and most recently includes cost recovery for Peak View.

South Dakota Electric has:

- An approved annual EIA tariff which recovers costs associated with generation plant environmental improvements. South Dakota Electric also has a TFA tariff which recovers the costs associated with transmission facility improvements. The EIA and TFA were suspended for a six-year moratorium period effective July 1, 2017. On January 7, 2020, South Dakota Electric received approval from the SDPUC on a settlement reached with the SDPUC staff agreeing to extend the 6-year moratorium period by an additional 3 years whereby rate increases for these recovery mechanisms will not go into effect prior to July 1, 2026. See Note 13 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for further information.

- An annual cost adjustment clause which provides for the over or under recovery of fuel, transmission and purchased power cost incurred to serve South Dakota customers. Additionally, this ECA contains an off-system sales sharing mechanism in which South Dakota customers will receive a credit equal to 100% of off-system power marketing operating income from the first $1.0 million of power marketing margin from short-term sales and a credit equal to 70% of power marketing margins from short-term sales in excess of the first $1.0 million. South Dakota Electric retains the remaining 30%. For the period of July 1, 2017 through March 31, 2023, the 100% credit of power marketing margin increased from $1.0 million to $2.0 million. The ECA methodology allows us to directly assign renewable resources and firm purchases to the customer load. In Wyoming, a similar fuel and purchased power cost adjustment is also in place.

- An approved FERC Transmission Tariff based on a formulaic approach that determines the revenue component of South Dakota Electric’s open access transmission tariff.

Wyoming Electric has:

- An annual cost adjustment mechanism that allows us to pass the prudently-incurred power costs above costs included in base rates through to electric customers. The annual cost adjustment allows for recovery of 85% of coal and coal-related cost per kWh variances from base and recovery of 95% of purchased power, transmission, and natural gas cost per kWh variances from base.

Tariff Filings. See Note 13 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for tariff filings and additional information regarding current rate activity.

Operating Statistics. The following tables summarize information for our Electric Utilities:

	For the year ended December 31,					
Degree Days	2019		2018		2017	
	Actual	Variance from Normal	Actual	Variance from Normal	Actual	Variance from Normal
Heating Degree Days:						
Colorado Electric	5,453	(3)%	5,119	4%	4,693	(16)%
South Dakota Electric	8,284	16%	7,749	8%	6,870	(4)%
Wyoming Electric	7,406	1%	7,036	(7)%	6,623	(12)%
Combined [(a)]	6,813	5%	6,405	3%	5,826	(11)%
Cooling Degree Days:						
Colorado Electric	1,226	37%	1,420	58%	1,027	14%
South Dakota Electric	404	(36)%	488	(23)%	709	11%
Wyoming Electric	462	33%	430	24%	429	23%
Combined [(a)]	791	14%	902	29%	798	14%

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

	Electric Revenue (in thousands)			Quantities Sold (MWh)		
	For the year ended December 31,			For the year ended December 31,		
	2019	2018	2017	2019	2018	2017
Residential	$ 216,108	$ 218,558	$ 210,172	1,440,551	1,450,585	1,390,952
Commercial	246,704	250,894	258,754	2,055,253	2,034,917	2,038,495
Industrial	131,831	124,668	122,958	1,787,412	1,682,074	1,598,755
Municipal	17,206	17,871	18,144	157,298	160,913	160,882
Subtotal Retail Revenue - Electric	611,849	611,991	610,028	5,440,514	5,328,489	5,189,084
Contract Wholesale [(a)]	19,078	33,688	30,435	368,360	900,854	722,659
Off-system/Power Marketing Wholesale	25,622	24,800	21,111	701,633	673,994	661,263
Other	56,203	40,972	43,076	—	—	—
Total Revenue and Energy Sold	712,752	711,451	704,650	6,510,507	6,903,337	6,573,006
Other Uses, Losses or Generation, net [(b)]	—	—	—	393,573	470,250	468,179
Total Revenue and Energy	712,752	711,451	704,650	6,904,080	7,373,587	7,041,185
Less cost of fuel and purchased power [(c)]	268,297	283,840	274,363			
Gross Margin (non-GAAP) [(c)] [(d)]	$ 444,455	$ 427,611	$ 430,287			

	Electric Revenue (in thousands)			Gross Margin (non-GAAP) [d] (in thousands)			Quantities Sold (MWh)		
	For the year ended December 31,			For the year ended December 31,			For the year ended December 31,		
	2019	2018	2017	2019	2018	2017	2019	2018	2017
Colorado Electric [c]	$ 247,332	$ 251,218	$ 251,090	$ 137,323	$ 138,901	$ 140,121	2,180,985	2,151,918	2,091,676
South Dakota Electric [a]	291,219	298,080	288,433	218,104	205,194	200,795	2,798,887	3,360,396	3,187,392
Wyoming Electric	174,201	162,153	165,127	89,028	83,516	89,371	1,924,208	1,861,273	1,762,117
Total Revenue, Gross Margin (non-GAAP), and Quantities Sold	$ 712,752	$ 711,451	$ 704,650	$ 444,455	$ 427,611	$ 430,287	6,904,080	7,373,587	7,041,185

(a) 2019 revenue and purchased power, as well as associated quantities, for a certain wholesale contract have been presented on a net basis. Prior year amounts were presented on a gross basis and, due to their immaterial nature, were not revised. This 2019 presentation change has no impact on Gross margin.
(b) Total MWh includes Other Uses, Losses or Generation, net, which is approximately 5%, 6%, and 6% for Colorado Electric, South Dakota Electric and Wyoming Electric, respectively.
(c) Due to the changes in our segment disclosures discussed in Note 5 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K, cost of fuel and purchased power was revised for the years ended December 31, 2018 and December 31, 2017 which resulted in an increase of $6.7 million and $6.0 million, respectively. There were corresponding decreases to Gross margin for both years. These changes had no impact on consolidated financial results.
(d) For further information on Gross Margin, see "Non-GAAP Financial Measure" within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K.

	For the year ended December 31,		
Quantities Generated and Purchased (MWh)	2019	2018	2017
Coal-fired	2,226,028	2,368,506	2,230,617
Natural Gas and Oil	600,002	446,373	307,815
Wind	238,999	253,180	239,472
Total Generated	3,065,029	3,068,059	2,777,904
Purchased [a]	3,839,051	4,305,528	4,263,281
Total Generated and Purchased	6,904,080	7,373,587	7,041,185

	For the year ended December 31,		
Quantities Generated and Purchased (MWh)	2019	2018	2017
Generated:			
Colorado Electric	443,770	481,446	397,965
South Dakota Electric	1,768,456	1,734,222	1,581,915
Wyoming Electric	852,803	852,391	798,024
Total Generated	3,065,029	3,068,059	2,777,904
Purchased:			
Colorado Electric	1,737,215	1,670,472	1,693,711
South Dakota Electric [a]	1,030,431	1,626,174	1,605,477
Wyoming Electric	1,071,405	1,008,882	964,093
Total Purchased	3,839,051	4,305,528	4,263,281
Total Generated and Purchased	6,904,080	7,373,587	7,041,185

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

Customers at End of Year	As of December 31, 2019	2018	2017
Residential	183,232	181,459	179,911
Commercial	29,921	29,299	29,354
Industrial	83	84	86
Other	1,024	1,030	914
Total Electric Customers at End of Year	214,260	211,872	210,265

Customers at End of Year	As of December 31, 2019	2018	2017
Colorado Electric	97,890	96,645	95,951
South Dakota Electric	73,052	72,533	72,184
Wyoming Electric	43,318	42,694	42,130
Total Electric Customers at End of Year	214,260	211,872	210,265

Gas Utilities Segment

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 1,066,000 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 49,000 retail distribution customers under the Choice Gas Program in Nebraska and Wyoming. Additionally, we provide services under the Service Guard Comfort Plan and Tech Services and also offer HomeServe products.

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 storage assets in Arkansas, Colorado and Wyoming, we also contract with many of the third-party transportation providers noted above 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, 2019:

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 tables summarize certain operating information for our Gas Utilities.

System Infrastructure (in line miles) as of December 31, 2019	Intrastate Gas Transmission Pipelines	Gas Distribution Mains	Gas Distribution Service Lines
Arkansas	942	4,880	1,161
Colorado	693	6,814	2,554
Iowa	165	2,813	2,138
Kansas	330	2,910	1,355
Nebraska	1,311	8,664	3,230
Wyoming	1,334	3,472	1,219
Total	4,775	29,553	11,657

	For the year ended December 31,					
Degree Days	2019		2018		2017	
	Actual	Variance From Normal	Actual	Variance From Normal	Actual	Variance From Normal
Heating Degree Days:						
Arkansas [(a)]	3,897	(4)%	4,169	3%	3,295	(19)%
Colorado	6,672	1%	6,136	(7)%	5,728	(14)%
Iowa	7,200	6%	7,192	6%	6,149	(9)%
Kansas [(a)]	5,190	6%	5,242	7%	4,452	(9)%
Nebraska	6,578	7%	6,563	6%	5,554	(10)%
Wyoming	8,010	7%	7,425	(1)%	7,123	(5)%
Combined [(b)]	6,840	5%	6,628	2%	5,862	(10)%

(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.

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 and 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 weather patterns that are cooler than normal and/or provide higher than normal precipitation; both of which can reduce natural gas 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. 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 distribution charge for transporting the gas through our distribution network.

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

Our Gas Utilities are authorized to use natural gas cost recovery mechanisms that allow them to adjust their rates to reflect changes in the wholesale cost of natural gas and to ensure that they recover all the costs prudently incurred in purchasing gas for their customers. In addition to natural gas cost recovery mechanisms, we have other recovery mechanisms, which vary by utility, but 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	Jurisdiction	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Authorized Capital Structure Debt/Equity	Authorized Rate Base (in millions)	Effective Date	Additional Tariffed Mechanisms
Gas Utilities:							
Arkansas Gas	AR	9.61%	6.82% (a)	50.9%/49.1%	$451.5 (b)	10/2018	GCA, Main Replacement Program, At-Risk Meter Relocation Program, Legislative or Regulatory Mandated Expenditures, Energy Efficiency, Weather Normalization Adjustment, Billing Determinant Adjustment
Colorado Gas	CO	9.6%	8.41%	50%/50%	$57.5	12/2012	GCA, Energy Efficiency Cost Recovery/DSM
Colorado Gas Dist.	CO	10.0%	8.02%	49.52%/ 50.48%	$127.1	12/2010	GCA, Energy Efficiency Cost Recovery/DSM
RMNG	CO	9.9%	6.71%	53.37%/ 46.63%	$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, Energy Efficiency Cost Recovery, 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	NE	10.1%	9.11%	48%/52%	$161.0	9/2010	GCA, Cost of Bad Debt Collected through GCA, Infrastructure System Replacement Cost Recovery Surcharge, Farm Tap Recovery Mechanism
Nebraska Gas Dist.	NE	9.6%	7.67%	48.84%/ 51.16%	$87.6/ $69.8 (c)	6/2012	Choice Gas Program, System Safety and Integrity Rider, Bad Debt expense recovered through Choice Supplier Fee
Wyoming Gas	WY	9.4%	6.98	49.77%/50.23%	$354.4	3/2020	GCA, Energy Efficiency Cost Recovery, 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) Total Nebraska Gas Distribution rate base of $87.6 million includes amounts allocated to serve non-jurisdictional customers. Jurisdictional Nebraska rate base totals $69.8 million and is used for calculation of jurisdictional base rates.

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						
	Energy Efficiency	Integrity Additions	Bad Debt	Weather Normal	Pension Recovery	Gas Cost	Billing Determinant Adjustment
Arkansas Gas	☑	☑		☑		☑	☑
Colorado Gas	☑					☑	
Colorado Gas Distribution	☑					☑	
RMNG	N/A	☑	N/A	N/A	N/A	N/A	N/A
Iowa Gas	☑	☑				☑	
Kansas Gas		☑	☑	☑	☑	☑	
Nebraska Gas		☑	☑			☑	
Nebraska Gas Distribution		☑	☑				
Wyoming Gas [(a)]	☑	☑				☑	

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(a) The Wyoming Gas integrity rider is effective March 1, 2020.

See Note 13 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for information regarding current rate activity.

Operating Statistics

	Revenue (in thousands)			Gross Margin (non-GAAP) [(a)] (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,		
	2019	2018	2017	2019	2018	2017	2019	2018	2017
Residential	$ 551,701	$ 567,785	$ 499,852	$ 285,802	$ 276,858	$ 255,626	66,956,080	65,352,164	54,645,598
Commercial	212,229	214,718	197,054	88,264	82,529	78,249	32,241,441	30,753,361	27,315,871
Industrial	24,832	26,466	24,454	8,053	7,056	6,226	6,548,023	6,309,211	5,855,053
Other	(1,361)	(7,899)	8,647	(1,361)	(7,899)	8,647	—	—	—
Total Distribution	787,401	801,070	730,007	380,758	358,544	348,748	105,745,544	102,414,736	87,816,522
Transportation and Transmission	144,710	141,854	135,824	144,710	141,850	135,824	153,101,264	148,299,003	141,600,080
Total Regulated	932,111	942,924	865,831	525,468	500,394	484,572	258,846,808	250,713,739	229,416,602
Non-regulated Services	77,919	82,383	81,799	58,664	62,760	53,455	—	—	—
Total Revenue, Gross Margin (non-GAAP) and Quantities Sold	$1,010,030	$1,025,307	$ 947,630	$ 584,132	$ 563,154	$ 538,027	258,846,808	250,713,739	229,416,602

	Revenue (in thousands)			Gross Margin (non-GAAP) [(a)] (in thousands)			Quantities Sold & Transported (Dth)		
	For the year ended December 31,			For the year ended December 31,			For the year ended December 31,		
	2019	2018	2017	2019	2018	2017	2019	2018	2017
Arkansas	$ 185,201	$ 176,660	$ 153,691	$ 115,899	$ 100,917	$ 94,007	30,496,243	30,931,390	26,491,537
Colorado	199,369	188,002	180,852	106,776	99,851	100,718	33,908,529	29,857,063	28,436,744
Iowa	151,619	161,843	143,446	70,290	68,384	66,619	41,795,729	40,668,682	37,013,645
Kansas	105,906	112,306	105,576	58,020	55,226	53,841	32,650,854	31,387,672	28,251,947
Nebraska	255,622	278,969	252,631	155,901	164,513	154,259	81,481,192	81,658,938	73,890,509
Wyoming	112,313	107,527	111,434	77,246	74,263	68,583	38,514,261	36,209,994	35,332,220
Total Revenue, Gross Margin (non-GAAP) and Quantities Sold	$1,010,030	$1,025,307	$ 947,630	$ 584,132	$ 563,154	$ 538,027	258,846,808	250,713,739	229,416,602

(a) For further information on Gross Margin, see "Non-GAAP Financial Measure" within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K.

	As of December 31,		
Customers at End of Year	2019	2018	2017
Residential	831,351	821,624	806,744
Commercial	82,912	82,498	86,461
Industrial	2,208	2,221	2,214
Transportation/Other	149,971	147,550	146,839
Total Customers at End of Year	1,066,442	1,053,893	1,042,258

	As of December 31,		
Customers at End of Year	2019	2018	2017
Arkansas	174,447	171,978	169,303
Colorado	191,950	186,759	181,876
Iowa	159,641	158,485	157,444
Kansas	115,846	114,840	114,082
Nebraska	293,576	291,723	290,264
Wyoming	130,982	130,108	129,289
Total Customers at End of Year	1,066,442	1,053,893	1,042,258

Utility Regulation Characteristics

State Regulations

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, 2019, we were subject to the following renewable energy portfolio standards or objectives:

- Colorado. Colorado adopted a renewable energy standard 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 from 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.

  On November 26, 2019, Black Hills Electric Generation placed in service Busch Ranch II. Black Hills Electric Generation provides the wind energy generated from Busch Ranch II to Colorado Electric under a 25-year PPA, which expires in November 2044. This renewable energy will enable Colorado Electric to comply with Colorado's Renewable Energy Standard.

- Montana. In 2005, Montana established a renewable portfolio standard that requires public utilities to obtain a percentage of their retail electricity sales from eligible renewable resources. In March 2013, South Dakota Electric filed a petition with the MTPSC requesting a waiver of the renewable portfolio standards primarily due to exceeding the applicable “cost cap” included in the standards. In March 2013, the Montana Legislature adopted legislation that had the effect of excluding South Dakota Electric from all renewable portfolio standard requirements under State Senate Bill 164, primarily due to the very low number of customers South Dakota Electric has in Montana and the relatively high cost of meeting the renewable requirements.

- South Dakota. South Dakota has adopted a renewable portfolio objective 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 no renewable energy portfolio standard.

Absent a specific renewable energy mandate in the territories we serve, our current strategy is to proactively integrate alternative and renewable energy into our utility energy supply while mitigating customer rate impacts. Mandatory portfolio standards have increased, and will likely continue to increase, the power supply costs of our Electric Utilities’ operations. Although we will seek to recover these higher costs in rates, we can provide no assurance that we will be able to secure full recovery of the costs we pay to be in compliance with standards or objectives. We cannot at this time reasonably forecast the potential costs associated with any new renewable energy standards that have been or may be proposed at the federal or state level.

Federal Regulation

Energy Policy Act. BHC is a holding company whose assets consist primarily of investments in our subsidiaries, including subsidiaries that are public utilities and a holding company regulated by FERC under the Federal Power Act and PUHCA 2005.

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 with a centralized service company subsidiary, BHSC, we are subject to FERC's authority under PUHCA 2005.

Power Generation Segment

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, 2019, we held varying interests in independent power plants with a total net ownership of approximately 423 MW.

We produce electric power from our generating plants and sell the electric capacity and energy, primarily to affiliates under a combination of mid- to long-term contracts, which mitigates the impact of a potential downturn in future power prices. We currently sell a majority of our non-regulated generating capacity under contracts having terms greater than one year.

As of December 31, 2019, the power plant ownership interests held by our Power Generation segment include:

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

(a) The Wygen I generation facility is a mine-mouth, coal-fired power plant with a total capacity of 90 MW located at our Gillette, Wyoming energy complex. We own 76.5% of the plant and MEAN owns the remaining 23.5%.
(b) On December 11, 2018, Black Hills Electric Generation purchased a 50% ownership interest in Busch Ranch I. This facility originally qualified under the Section 1603 program grant in lieu of ITCs.
(c) On November 26, 2019, Black Hills Electric Generation placed in service Busch Ranch II.
(d) On February 5, 2019, Black Hills Electric Generation purchased 80 MW of wind generating assets in Iowa. A third-party operates the facility and we sell the wind energy generated in the MISO market.
(e) This facility qualifies for PTCs at $25/MWh under IRC 45 during the 10-year period beginning on the date the facility was originally placed in service.

Power Sales Agreements. Our Power Generation facilities have various long-term power sales agreements. See Note 19 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for further information.

Third Party Noncontrolling Interest in Subsidiary. In 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for $216 million to a third party buyer. See Note 12 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

The following table summarizes MWh for our Power Generation segment:

Quantities Sold, Generated and Purchased (MWh) [a]	For the year ended December 31, 2019	2018	2017
Sold			
Black Hills Colorado IPP	935,997	1,000,577	943,618
Black Hills Wyoming [b]	629,788	582,938	645,810
Black Hills Electric Generation [c]	167,296	5,873	—
Total Sold	1,733,081	1,589,388	1,589,428
Generated			
Black Hills Colorado IPP	935,997	1,000,577	943,618
Black Hills Wyoming [b]	557,119	501,945	577,124
Black Hills Electric Generation [c]	167,296	5,873	—
Total Generated	1,660,412	1,508,395	1,520,742
Purchased			
Black Hills Wyoming [b]	74,199	83,213	69,377
Total Purchased	74,199	83,213	69,377

(a) Company use and losses are not included in the quantities sold, generated and purchased.
(b) Under the 20-year economy energy PPA (discussed in Note 19 of the Notes to the 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.
(c) Black Hills Electric Generation amounts in this table are related to wind facilities held by our Power Generation segment. Change from 2018 to 2019 is driven by acquisition, and placing in service, of new wind assets.

Operating Agreements. Our Power Generation segment has the following material operating agreements:

- Black Hills Wyoming's economy energy PPA and other ancillary agreements are discussed in Note 19 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

- Operating and Maintenance Services Agreement

  - In conjunction with the sale of a noncontrolling interest in 2016, an operating and maintenance services agreement was entered into between Black Hills Electric Generation and Black Hills Colorado IPP. This agreement sets forth the obligations and responsibilities of Black Hills Electric Generation as the operator of the generating facility owned by Black Hills Colorado IPP. This agreement became effective on the date of the noncontrolling interest purchase and remains effective as long as the operator or one of its affiliates is responsible for managing the generating facilities in accordance with the noncontrolling interest agreement, or until termination by owner or operator.

- Shared Services Agreements
  - South Dakota Electric, Wyoming Electric and Black Hills Wyoming are parties to a shared facilities agreement, whereby each entity is charged for the use of assets by the affiliate entity.
  - Black Hills Colorado IPP and Colorado Electric are parties to a facility fee agreement, whereby Colorado Electric charges Black Hills Colorado IPP for the use of Colorado Electric's assets.
  - Black Hills Colorado IPP, Wyoming Electric and South Dakota Electric are parties to a Spare Turbine Use Agreement, whereby Black Hills Colorado IPP charges South Dakota Electric and Wyoming Electric a monthly fee for the availability of a spare turbine to support the operation of Cheyenne Prairie.
  - Black Hills Colorado IPP and Black Hills Wyoming receive certain staffing and management services from BHSC.
- Jointly owned facilities agreements are discussed in Note 4 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

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

With respect to the merchant power sector, FERC has taken steps to increase access to the national transmission grid by utility and non-utility purchasers and sellers of electricity and foster competition within the wholesale electricity markets. Our Power Generation business could face greater competition if utilities are permitted to robustly invest in power generation assets. Conversely, state regulatory rules requiring utilities to competitively bid generation resources may provide opportunity for independent power producers in some regions.

The Energy Policy Act of 1992. The passage of the Energy Policy Act of 1992 encouraged independent power production by providing certain exemptions from regulation for EWGs. EWGs are exclusively in the business of owning or operating, or both owning and operating, eligible power facilities and selling electric energy at wholesale. EWGs are subject to FERC regulation, including rate regulation. We own five EWGs: Wygen I, Pueblo Airport Generation, Busch Ranch I, Busch Ranch II and Top of Iowa. Our EWGs were granted market-based rate authority, which allows FERC to waive certain accounting, record-keeping and reporting requirements imposed on public utilities with cost-based rates.

Mining Segment

Our Mining segment operates 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 in eastern Wyoming. We produced approximately 3.7 million tons of coal in 2019.

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 in recent years trended upwards. The overburden ratio at December 31, 2019 was 2.30 which increased from the prior year as we continued mining in areas with higher overburden. We expect our stripping ratio to be approximately 2.18 by the end of 2020 as we mine in areas with comparable 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. We pay federal and state royalties of 12.5% of the selling price of all coal. As of December 31, 2019, we estimated our recoverable reserves to be approximately 185 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 50 years at the current production levels. Our recoverable reserve estimates are periodically updated to reflect past production and other geological and mining data. Changes in mining methods or the utilization of new technologies may increase or decrease the recovery basis for a coal seam. Our recoverable reserves include reserves that can be economically and legally extracted at the time of their determination.

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

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

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

- The 362 MW Wyodak Plant owned 80% by PacifiCorp and 20% by South Dakota Electric. PacifiCorp is obligated to purchase a minimum of 1.5 million tons each year of the contract term, subject to adjustments for planned outages. 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. This contract expires December 31, 2022 and negotiations are underway to extend the contract;

- The 110 MW Wygen III power plant 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. This contract expires June 1, 2060;

- The 90 MW Wygen I power plant owned 76.5% by Black Hills Wyoming and 23.5% by MEAN to which we sell approximately 500,000 tons each year. This contract expires June 30, 2038; and

- Certain regional industrial customers served by truck to which we sell a total of approximately 150,000 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. South Dakota Electric made a commitment to the SDPUC, the WPSC and the City of Gillette that coal for South Dakota Electric's operating plants would be furnished and priced as provided by that agreement for the life of the Neil Simpson II plant and through June 1, 2060, for Wygen III. The agreement with Wyoming Electric provides coal for the life of the Wygen II plant.

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 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 using a base price that includes price escalators and quality adjustments through June 30, 2038 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. The agreement stipulates that WRDC will supply coal to the 90 MW Wygen I plant through June 30, 2038.

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. Management continues to explore the limited market opportunities for our product through truck transport.

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 considerations and availability 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 required during production and after mining has been completed. Under applicable law, we must submit applications to, and receive approval from, the WDEQ 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. Based on extensive reclamation studies, we have accrued approximately $14 million for reclamation costs as of December 31, 2019. See additional information in Note 8 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

Environmental Matters

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. The BLM repealed similar hydrocarbon and methane emissions reductions it previously established under the Methane Rule (Venting and Flaring rule). Presently, we have four facilities in our Colorado natural gas transmission operations affected by the hydrocarbon and methane reduction rules.

Our operations are currently 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. We plan to develop a corporate-wide methane control strategy to address GHG emissions as we anticipate this will be a requirement in future rule-making efforts.

Water Issues. Our facilities are subject to a variety of state and federal regulations governing existing and potential water/wastewater discharges and protection of surface waters from oil pollution. Generally, such regulations are promulgated under the Clean Water Act and govern overall water/wastewater discharges through EPA's surface water discharge and storm water permits. All of our facilities that are required to have such permits have those permits in place and are in compliance with discharge limitations and plan implementation requirements. The EPA proposed effluent limitation guidelines and standards on June 7, 2013, and published the final rule on November 3, 2015. In 2017, the EPA postponed the implementation of the rule and set a timeline in 2018 to revise the rule. To date, the rule is being reviewed by the Office of Management and Budget. This rule will have an impact on the Wyodak Plant. Until the EPA issues the rule for publication, we cannot quantify what the potential impact may be on the Wyodak Plant. The terms of this new regulation may impact the next permit renewal, which will be in 2020.

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 SO_2, NO_x 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 SO_2 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 the power plant down if a predicted emission limit is to be exceeded. Similar efforts have been taken and similar results achieved with our natural gas fired combustion turbine sites as well.

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 and overruled it in a Federal Implementation Plan (FIP). The State of Wyoming and other interested parties are challenging the EPA's determination. If the challenge is unsuccessful, additional capital investment would be necessary to bring the Wyodak Plant into compliance. South Dakota Electric's 20% share of this capital investment for the facility would be approximately $27 million if PacifiCorp is required to install a Selective Catalytic Reactor for NO_x control. The case is currently held in abeyance at the 10th circuit court as the parties work on a settlement. Basin Electric, who is part of the legal action, settled with the EPA. In lieu of going to court, PacifiCorp entered into mediation with the EPA and conservation groups. PacifiCorp submitted a "Request for Reconsideration" on October 24, 2019 to the EPA and provided a copy to the court. The purpose of the submittal is to revisit the emission impacts and cost of additional investment.

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 and industrial 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.

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. We are currently in discussions with the EPA, state regulators, and/or other third-parties to determine the ultimate resolution to these sites. As of December 31, 2019, our Gas Utilities have two active FMGP sites, which are located in Council Bluffs, Iowa, and McCook, Nebraska. For the Council Bluffs site, the delay in clean-up is due to identifying the Potential Responsible Parties (PRPs or Successors to the Operators) to pay for the clean-up. We are the landowner and not the Successors to the Operator, whom would be responsible for paying for the majority of clean-up. We have been working with the EPA to identify the PRPs. The EPA has sent out information requests to the PRPs seeking transaction documents to determine the Successors to the Operators of the site who created the contamination. For the McCook, Nebraska site, we have been contacted by a third-party who intends to manage and pay for the clean-up at this site. The third-party is conducting site assessments and working with the State of Nebraska on a clean-up plan.

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 rule. This rule focuses on heat-rate improvements on coal-fired boiler units. In July 2019, the rule was finalized and applies only to our coal-fired plants. These plants have implemented or plan to implement a majority of the efficiency requirements listed in the rule.

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 current administration has not pursued further modification of the CCR.

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 19 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

Other Properties

In addition to the facilities previously disclosed in Items 1 and 2, we own or lease several facilities throughout our service territories. Our owned facilities are as follows:

- In Rapid City, South Dakota, we have a 220,000 square foot corporate headquarters building, Horizon Point, which was completed in 2017.
- In Arkansas, Colorado, Iowa, Kansas, Nebraska, and Wyoming we own various office, service center, storage, shop and warehouse space totaling over 1,030,000 square feet utilized by our Gas Utilities.
- In Colorado, South Dakota, and Wyoming we own various office, service center, storage, shop and warehouse space totaling approximately 305,000 square feet utilized by our Electric Utilities and Mining segments.

In addition to our owned properties, we lease 92,527 square feet of properties within our service areas.

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.

Employees

At December 31, 2019, we had 2,944 employees. Approximately 25% of our employees are represented by a union. We have not experienced any labor stoppages in recent years. At December 31, 2019, approximately 22% of our total employees and 25% 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.

The following table sets forth the number of employees included in continuing operations:

	Number of Employees At December 31, 2019
Corporate and Shared Services	1,273
Electric Utilities and Gas Utilities	1,609
Power Generation and Mining	62
Total	2,944

At December 31, 2019, certain employees of our Electric Utilities and Gas Utilities were covered by the following collective bargaining agreements:

Utility	Number of Employees	Union Affiliation	Expiration Date of Collective Bargaining Agreement
Colorado Electric	102	IBEW Local 667	April 15, 2023
South Dakota Electric	135	IBEW Local 1250	March 31, 2024
Wyoming Electric	23	IBEW Local 111	June 30, 2024
Iowa Gas	113	IBEW Local 204	July 31, 2020
Kansas Gas	18	Communications Workers of America, AFL-CIO Local 6407	December 31, 2024
Nebraska Gas	99	IBEW Local 244	March 13, 2022
Nebraska Gas [(a)]	146	CWA Local 7476	October 30, 2019
Wyoming Gas [(a)]	101	CWA Local 7476	October 30, 2019
Total	737		

(a) In the 2016 negotiations with the CWA Local 7476, the union agreed to disclaim their interest in Colorado Gas employees and to split the remaining bargaining unit into two distinct bargaining units, Nebraska Gas and Wyoming Gas. There are ongoing negotiations with both bargaining units at this time.

ITEM 1A. RISK FACTORS

OPERATING RISKS

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

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

Our results of operations depend, in significant part, on our ability to execute our strategic business plans and growth strategy. Technology advancements, disruptive forces and innovations in the marketplace and changing business or regulatory conditions may negatively impact our current plans and strategies. An inability to successfully and timely adapt to changing conditions and execute our strategic plans and growth strategy could materially affect our financial operating results including earnings, cash flow and liquidity.

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

Our regulated Electric and Gas Utilities are subject to cost-of-service 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 retail 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. 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. 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 recovery of our costs and the allowed return on invested capital. In addition, rate decisions could be influenced by many factors, including general economic conditions and the political environment.

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 the state utility commission subsequently determines that such costs should not have been paid by the customers, we may be required to refund such costs. Any such costs not recovered through rates, or any such refund, could adversely affect financial operating results including earnings, cash flow and liquidity.

We may be subject to future laws, regulations, or actions associated with fossil-fuel generation and GHG emissions.

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 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.

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 storage facilities or 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.

Our financial performance depends on the successful management of our facilities operations, including ongoing operation, construction, expansion, and refurbishment.

Operation, construction, expansion and refurbishment of electric generating facilities, electric and natural gas transmission and distribution systems, natural gas storage facilities, and a coal mine involve risks that could result in fires, explosions, property damage and personal injury, including death. These risks include:

- Inherent dangers. Electricity and natural gas are dangerous for employees and the general public; contact with power lines, natural gas pipelines, electrical or natural gas service facilities and equipment can result in fires and explosions, causing significant property damage and personal injuries, including death;
- Weather, natural conditions and disasters. Severe weather events could negatively impact operations, including our ability to provide energy safely and reliably and our ability to complete construction, expansion or refurbishment of facilities as planned. Extreme natural conditions and other disasters such as wind, lightning, flooding and winter storms, can cause wildfires, electric transmission or distribution pole failures, natural gas pipeline interruptions, outages, property damage and personal injury;
- 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;

- 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, 2019, approximately 25% 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 a total of eight collective bargaining agreements.

- Equipment and processes. Breakdown or failure of equipment or processes, the unavailability or increased cost of equipment, and performance below expected levels of output or efficiency could negatively impact our results of operations. New plants may employ recently developed and technologically complex equipment, including newer environmental emission control technology.

- 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 product and satisfy our contractual obligations may be hindered;

- Natural gas supply for generation and distribution. Our utilities 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, which could limit our utilities' ability to operate their facilities;

- 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 environmental and pipeline safety laws and regulations; unexpected engineering, environmental and geological problems; and unanticipated cost overruns could negatively impact our results of operations;

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

- Disruption in the functioning of our information technology and network infrastructure which is vulnerable to disability, failures and unauthorized access. If our information technology systems were to fail and we were unable to recover in a timely manner, we would be unable to fulfill critical business functions.

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.

Our energy production, transmission and distribution activities, and our storage facilities for our natural gas involve numerous risks that may result in accidents and other catastrophic events.

Inherent in our businesses are a variety of hazards and operating risks, such as leaks, blowouts, fires, releases of hazardous materials, explosions and operational problems. Many of our transmission and distribution assets are located near populated residential areas, commercial business centers and industrial sites.

These hazards could result in injury or loss of human life, cause environmental pollution, significantly damage property or natural resources or impair our ability to operate our facilities. 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 and could have a material adverse effect on our financial operating results including earnings, cash flow and liquidity.

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

Our financial operating results are impacted by demand in our service territories. Customer growth and usage may be impacted by a number of factors, including the voluntary reduction of consumption of electricity and natural gas by our customers in response to increases in prices and energy efficiency programs, 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.

Cyberattacks, terrorism, or other malicious acts 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, SCADA, information technology systems and network infrastructure to 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 information 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 a significant decrease in revenues, as well as significant expense to repair system damage and remedy security breaches. 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. The security measures and safeguards we have implemented may not always be effective. Despite our implementation of security measures and safeguards, all of our information technology systems may be vulnerable to disability, failures or unauthorized access

Risks associated with deployment of capital may impact our ability to execute our business plans and growth strategy.

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

Weather conditions may cause fluctuation in customer usage as well as service disruptions.

Our utility businesses are seasonal businesses and weather conditions and patterns can have a material impact on our operating performance. Demand for electricity is typically greater in the summer and winter months associated with cooling and heating, respectively. Demand for natural gas depends heavily upon winter-weather patterns throughout our service territory and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our 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 results of operations, financial position or cash flows.

Our businesses are located in areas that could be subject to severe weather events such as snow and ice storms, tornadoes, strong winds, significant thunderstorms, flooding and drought. These events could result in lost operating revenues due to outages, property damage, including inoperable generation facilities and downed transmission and distribution lines, and storm restoration activities. We may not be able to recover the costs incurred following these weather events resulting in a negative impact on our financial operating results including earnings, cash flow and liquidity.

We may be subject to increased risks of regulatory 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.

Certain Federal laws provide special protection to certain designated animal species. These laws and any state equivalents provide for significant civil and criminal penalties for non-permitted activities that result in harm to or harassment of certain protected animals, including damage to their habitats. If such species are located in an area in which we conduct operations, or if additional species in those areas become subject to protection, our operations and development projects, particularly transmission, generation, wind and pipeline projects, could be restricted or delayed, or we could be required to implement expensive mitigation measures.

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.

FINANCING 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 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.

Derivatives regulations could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices and interest rates.

Dodd-Frank contains significant derivatives regulations, including a requirement that certain transactions be cleared resulting in a requirement to post cash collateral (commonly referred to as "margin") for such transactions. Dodd-Frank provides for a potential exception from these clearing and cash collateral requirements for commercial end-users such as utilities and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and the parties to those transactions.

We use derivative instruments for our hedging activities for our Gas and Electric Utilities' operations. We may also use interest rate derivative instruments to minimize the impact of interest rate fluctuations. As a result of Dodd-Frank regulations promulgated by the CFTC, we may be required to post collateral for certain swap transactions we enter into. In addition, our exchange-traded futures contracts are subject to futures margin posting requirements, which 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. In addition, a requirement for our counterparties to post collateral could result in additional costs being passed on to us, thereby decreasing our profitability.

Our hedging activities that are designed to protect against commodity price and financial market risks may cause fluctuations in reported financial results due to mark-to-market accounting treatment.

We use various financial contracts and derivatives, including futures, forwards, options and swaps to manage commodity price and financial market 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. Fluctuating commodity prices could have a negative effect on our liquidity, financial condition, and results of operations.

Our use of derivative financial instruments could result in material financial losses.

From time to time, we have sought to limit a portion of the potential adverse effects resulting from changes in commodity prices and interest rates by using derivative financial instruments and other hedging mechanisms. 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.

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

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 because they 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 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, if one occurs, may lead to an increase in late payments from retail, 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.

Our ability to obtain insurance and the terms of any available insurance coverage could be adversely affected by international, national, state or local events and company-specific events, as well as the financial condition of insurers. Our insurance coverage may not provide protection against all significant losses.

Our ability to obtain insurance, as well as the cost of such insurance, could be impacted by developments affecting insurance businesses, international, national, state or local events, as well as the financial condition of insurers. Insurance coverage may not continue to be available at all, or at rates or on terms similar to those presently available to us. A loss for which we are not fully insured could materially and adversely affect our financial results. Our insurance may not be sufficient or effective under all circumstances and against all hazards or liabilities to which the Company may be subject, including but not limited to environmental hazards, fire-related liability from natural events or inadequate facility maintenance, distribution property losses, cyber-security risks and dangers that exist in the gathering and transportation of gas in pipelines.

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, and likely will continue to, require changes to our current employee benefit plans and in our administrative and accounting 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 can be no assurance that the state public utility commissions will allow recovery. The increasing cost, or inadequate recovery of, rising employee benefit costs may adversely affect our financial operating results including earnings, cash flow, or liquidity.

An effective system of internal control may not be maintained, leading to material weaknesses in internal control over financial reporting.

Section 404 of the Sarbanes-Oxley Act of 2002 requires management to make an assessment of the design and effectiveness of internal controls. Our independent registered public accounting firm is required to attest to the effectiveness of these controls. During their assessment of these controls, management or our independent registered public accounting firm may identify areas of weakness in control design or effectiveness, which may lead to the conclusion that a material weakness in internal control exists. Any control deficiencies we identify in the future could adversely affect our ability to report our financial results on a timely and accurate basis, which could result in a loss of investor confidence in our financial reports or have a material adverse effect on our ability to operate our business or access sources of liquidity.

A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control system's objectives will be met. If we are unable to assert that our internal controls over financial reporting are effective, market perception of our business, operating results and stock price could be adversely affected.

ENVIRONMENTAL RISKS

Developments in federal and state laws concerning GHG regulations and air emissions relating to climate could materially increase our generation costs and render some of our generating units uneconomical to operate and maintain.

To the extent climate change occurs, our businesses could be adversely impacted. Warmer temperatures during the heating season in our utility service territories, or cooler temperatures during the cooling season in our electric service territories could adversely affect financial results through lower natural gas volumes delivered, lower MWh sold and associated lower revenues.

We own and operate regulated and non-regulated fossil-fuel generating plants in Colorado, South Dakota and Wyoming. Developments under federal and state laws and regulations governing air emissions from fossil-fuel generating plants may result in more stringent emission limitations, which could have a material impact on our costs of operations. Various pending or final state and EPA regulations that will impact our facilities are also discussed in Item 1 of this Annual Report on Form 10-K under the section "Environmental Matters".

There is uncertainty surrounding current climate regulation due to legal challenges, new federal climate legislation anticipated in the future, or state climate legislation and regulation. We cannot definitively estimate the effect of GHG legislation or regulation on our results of operations, financial position or cash flows.

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 reduction of load of coal-fired power generation facilities and potential increased load of our combined cycle natural gas-fired generation units. To the extent our regulated fossil-fuel generating plants are included in rate base we will attempt to recover costs associated with complying with emission standards or other requirements. We will also attempt to recover the emission compliance costs of our non-regulated fossil-fuel generating plants from utility and other purchasers of the power generated by those non-regulated power plants. Any unrecovered costs could have a material impact on our results of operations and financial condition. In addition, future changes in environmental regulations governing air emissions could render some of our power generating units more expensive or uneconomical to operate and maintain; this could cause those generating units to be de-commissioned, potentially resulting in impairment costs. We will attempt to recover any remaining asset value; however, any unrecovered costs could have a material impact on our results of operations and financial condition.

The costs to achieve or maintain compliance with existing or future governmental laws, regulations or requirements, or failure to comply, could increase significantly.

Our business segments are subject to numerous environmental laws and regulations affecting many aspects of present and future operations, including air emissions, 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 to comply with environmental regulations may result in the imposition of fines, penalties and injunctive measures affecting operating assets.

The business segments may not be successful in recovering 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 the business segments' financial position, results of operations or cash flows, future environmental compliance costs could have a significant negative impact.

The characteristics of coal may make it difficult for coal users to comply with various environmental standards related to coal combustion or utilization.

Future regulations may require further reductions in emissions of mercury, hazardous pollutants, SO_2, NO_x, volatile organic compounds, particulate matter and GHG, which are released into the air when coal is burned. These requirements could require the installation of costly emission control technology or the implementation of other measures.

Coal competes with other energy sources, such as natural gas, wind, solar and hydropower. The EPA was directed to repeal, revise and replace the CPP rule. At this time, it is not known what effect this will have on coal as a domestic energy source, and could have a significant impact on our mining operations.

Existing or proposed legislation focusing on emissions enacted by the United States or individual states could make coal a less attractive fuel alternative for our customers and could impose a tax or fee on the producer of the coal. If our customers decrease the volume of coal they purchase from us or switch to alternative fuels as a result of existing or future environmental regulations aimed at reducing emissions, our financial operating results including earnings, cash flow and liquidity could be adversely impacted.

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 19, "Commitments and Contingencies", of our Notes to the 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 Dodd-Frank is included in Exhibit 95 of this Annual Report.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

David R. Emery, age 57, has been Executive Chairman since January 1, 2019, Chairman and Chief Executive Officer from 2016 through 2018, and Chairman, President and Chief Executive Officer from 2005 through 2015. Prior to that, he held various positions with the Company, including President and Chief Executive Officer and member of the Board of Directors from 2004 to 2005, President and Chief Operating Officer — Retail Business Segment from 2003 to 2004 and Vice President — Fuel Resources from 1997 to 2003. Mr. Emery has 30 years of experience with the Company.

Linden R. Evans, age 57, 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 18 years of experience with the Company.

Scott A. Buchholz, age 58, has been our Senior Vice President — Chief Information Officer since the closing of the Aquila Transaction in 2008. Prior to joining the Company, he was Aquila's Vice President of Information Technology from 2005 until 2008, Six Sigma Deployment Leader/Black Belt from 2004 until 2005, and General Manager, Corporate Information Technology from 2002 until 2004. Mr. Buchholz has 39 years of experience with the Company, including 28 years with Aquila.

Brian G. Iverson, age 57, 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 16 years of experience with the Company.

Richard W. Kinzley, age 54, 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 20 years of experience with the Company.

Jennifer C. Landis, age 45, 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 18 years of experience with the Company.

Karen Beachy, age 48, has been Senior Vice President - Growth and Strategy since August 26, 2019. She served as Vice President - Growth and Strategy from 2018 to August 2019, Vice President - Supply Chain from 2016 to 2018, and Director of Supply Chain from 2014 to 2016. Ms. Beachy has 5 years of experience with the Company.

Stuart Wevik, age 58, 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 34 years of experience with the Company.

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 December 31, 2019, we had 3,586 common shareholders of record and 32,285 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 29, 2020 meeting, our Board of Directors declared a quarterly dividend of $0.535 per share, equivalent to an annual dividend rate of $2.14 per share. This equivalent rate, if declared and paid in 2020, will represent 50 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 2019.

ISSUER PURCHASES OF EQUITY SECURITIES

There were no equity securities acquired for the twelve months ended December 31, 2019.

ITEM 6. SELECTED FINANCIAL DATA

(Minor differences may result due to rounding)

Years Ended December 31, (dollars in thousands, except per share amounts)	2019		2018		2017		2016 [a]		2015	
Total Assets	$ 7,558,457		$ 6,963,327		$ 6,658,902		$ 6,541,773		$ 4,626,643	
Property, Plant and Equipment										
Property, plant and equipment	$ 6,784,679		$ 6,000,015		$ 5,567,518		$ 5,315,296		$ 3,849,309	
Accumulated depreciation and depletion	(1,281,493)		(1,145,136)		(1,026,088)		(929,119)		(794,695)	
Total property, plant and equipment, net	$ 5,503,186		$ 4,854,879		$ 4,541,430		$ 4,386,177		$ 3,054,614	
Capital Expenditures										
Continuing Operations	$ 849,755		$ 502,424		$ 337,689		$ 460,450		$ 289,896	
Discontinued Operations [b]	—		2,402		23,222		6,669		168,925	
Total Capital Expenditures	$ 849,755		$ 504,826		$ 360,911		$ 467,119		$ 458,821	
Capitalization (excluding noncontrolling interests)										
Current maturities of long-term debt	$ 5,743		$ 5,743		$ 5,743		$ 5,743		$ —	
Notes payable	349,500		185,620		211,300		96,600		76,800	
Long-term debt, net of current maturities	3,140,096		2,950,835		3,109,400		3,211,189		1,853,682	
Total stockholders' equity	2,362,123		2,181,588		1,708,974		1,614,639		1,465,867	
Total capitalization	$ 5,857,462		$ 5,323,786		$ 5,035,417		$ 4,928,171		$ 3,396,349	
Total Operating Revenues	$ 1,734,900		$ 1,754,268		$ 1,680,266		$ 1,538,916		$ 1,261,322	
Net Income Available for Common Stock										
Income from continuing operations available for common stock	199,310	(c) (g)	265,329	(c) (f)	194,133	(c) (d)	137,132	(c) (d)	141,548	(d)
Income (loss) from discontinued operations, net of tax [b]	—		(6,887)		(17,099)		(64,162)		(173,659)	
Net income (loss) available for common stock	$ 199,310		$ 258,442		$ 177,034		$ 72,970		$ (32,111)	
Common Stock Data[e] (in thousands)										
Shares outstanding, average basic	60,662		54,420		53,221		51,922		45,288	
Shares outstanding, average diluted	60,798		55,486		55,120		53,271		45,288	
Shares outstanding, end of year	61,477		60,004		53,541		53,382		51,192	

SELECTED FINANCIAL DATA continued

Years Ended December 31, (dollars in thousands, except per share amounts)	2019	2018	2017	2016	2015
Earnings (Loss) Per Share of Common Stock (in dollars)					
Basic earnings (loss) per average share -					
Continuing operations	$ 3.52	$ 5.14	$ 3.92	$ 2.83	$ 3.12
Discontinued operations (b)	—	(0.13)	(0.32)	(1.23)	(3.83)
Non-controlling interest (c)	(0.23)	(0.26)	(0.27)	(0.19)	—
Total	$ 3.29	$ 4.75	$ 3.33	$ 1.41	$ (0.71)
Diluted earnings (loss) per average share -					
Continuing operations	$ 3.51	$ 5.04	$ 3.78	$ 2.75	$ 3.12
Discontinued operations (b)	—	(0.12)	(0.31)	(1.20)	(3.83)
Non-controlling interest (c)	(0.23)	(0.26)	(0.26)	(0.18)	—
Total	$ 3.28	$ 4.66	$ 3.21	$ 1.37	$ (0.71)
Cash Dividends Paid on Common Stock	$ 124,647	$ 106,591	$ 96,744	$ 87,570	$ 72,604
Dividends Declared per Share	$ 2.05	$ 1.93	$ 1.81	$ 1.68	$ 1.62
Book Value Per Share, End of Year	$ 38.42	$ 36.36	$ 31.92	$ 30.25	$ 28.63

(a) Effective February 12, 2016, we completed the SourceGas Transaction. Total cash consideration paid, net of debt assumed and working capital adjustment received, was $1.124 billion, funded with a combination of the issuance of 6.3 million shares of our common stock on November 23, 2015, 5.98 million equity units issued on November 23, 2015, $546 million of net proceeds from the issuance of senior unsecured notes on January 13, 2016, cash on hand and draws under our revolving credit facility.

(b) On November 1, 2017, we made the decision to divest our Oil and Gas assets which was completed in 2018. Oil and Gas results are shown in discontinued operations. 2017 includes a non-cash after-tax fair value impairment on held-for-sale assets of $13 million. 2016 includes non-cash after-tax impairment charges to crude oil and natural gas properties of $67 million. 2015 includes non-cash after-tax impairment charges to crude oil and natural gas properties of $158 million.

(c) On April 14, 2016, Black Hills Electric Generation sold a 49.9% interest in Black Hills Colorado IPP. Net income available for common stock for 2019, 2018, 2017 and 2016 was reduced by $14 million, $14 million, $14 million and $9.6 million, respectively, attributable to this noncontrolling interest.

(d) 2017, 2016 and 2015 include incremental SourceGas Transaction costs, after-tax of $2.8 million, $30 million and $6.7 million, respectively.

(e) In 2019, we issued 1.33 million shares at an average share price of $75.28 under our ATM equity offering program. On November 1, 2018, we issued 6.3 million shares of common stock upon conversion of our Equity Units. In 2016, we issued 1.97 million shares at an average share price of $60.95 under our ATM equity offering program.

(f) The increase in 2018 included a $73 million tax benefit resulting from legal entity restructuring. See Note 15 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for more information.

(g) 2019 includes a non-cash after-tax impairment of $15 million in our investment in equity securities of a privately held oil and gas company. See Note 1 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for more information.

For additional information on our business segments see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Item 7A, Quantitative and Qualitative Disclosures about Market Risk and Note 5 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

ITEMS 7 & and 7A. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS AND QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Items 7 and 7A Index

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 electricity and natural gas through its Electric and Gas Utilities to 1.3 million customers in 824 communities in eight states, including Arkansas, Colorado, Iowa, Kansas, Montana, Nebraska, South Dakota and Wyoming. 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. 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 long-term contracts. Our Mining segment produces coal at our only location near Gillette, Wyoming, and sells nearly all production to fuel the on-site, mine-mouth power generation facilities.

The Company has provided energy and served customers for 136 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. Our strategy today continues that emphasis on serving customers, but with a renewed focus on better engaging with 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. We are *Ready* to serve as we have done for the past 136 years.

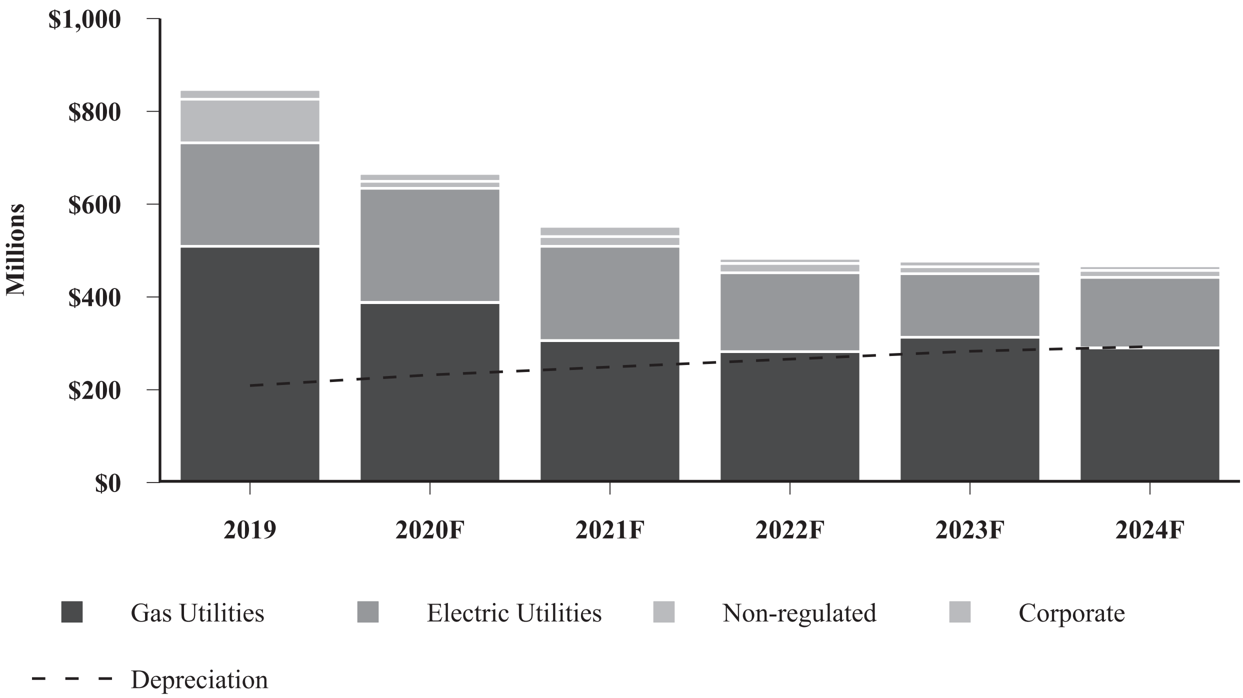
Our strategy consists of five primary areas that focus on improving the way we serve customers with safe, reliable and affordable energy while improving the lives of the customers and communities we serve. The strategy is to 1) become the safest energy company in the utility industry; 2) transform the customer experience; 3) grow our electric and natural gas customer load; 4) pursue operating efficiencies; and 5) modernize utility infrastructure. This strategic focus will present the company with significant investment needs as we modernize our infrastructure systems and meet customer growth. 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 and affordable energy. Our utilities own and operate large electric and natural gas infrastructure systems that span nearly 1,600 miles. Our Electric Utilities own and operate 939 MW of generation capacity and 8,900 miles of transmission and distribution lines and our Gas Utilities own and operate 46,000 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 and to ensure the continued delivery of safe, reliable and affordable energy. In addition, we need to 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 system 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. Many 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.

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 2019 and forecasted capital expenditures and depreciation for next five years from 2020 through 2024 are as follows (in millions):



Capital Expenditures By Segment	Actual 2019	Planned 2020	Planned 2021	Planned 2022	Planned 2023	Planned 2024
(in millions)						
Electric Utilities	$ 223	$ 246	$ 203	$ 170	$ 137	$ 152
Gas Utilities	512	391	309	285	316	293
Power Generation	85	7	9	11	6	6
Mining	9	8	12	9	9	9
Corporate and Other	21	17	22	11	12	10
Total	$ 850	$ 669	$ 555	$ 486	$ 480	$ 470

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

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

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

- When generating assets are included in the utility rate base and reviewed and approved by government authorities, customer rates are more stable and predictable, and typically less expensive in the long run; especially when compared to power otherwise purchased from the open market through wholesale contracts that are periodically re-priced to reflect current and varying market conditions;

- Regulators participate in a planning process where long-term investments are designed to match long-term energy demand;

- The lower-risk profile of rate-based generation assets contributes to stronger credit ratings which, in turn, can benefit both customers and investors by lowering the cost of capital; and

- Investors are provided a long-term, reasonable, stable return on their investment.

Proactively integrate alternative and renewable energy into our utility energy supply while mitigating customer rate impacts. Some of our customers, particularly our larger customers, are demanding more renewable and cleaner sources of energy to meet their sustainability goals. In addition, there is more interest from voters, regulators and legislators to increase the use of renewable and other alternative energy sources. To support this interest, we have created and received approvals for new, voluntary renewable energy tariffs to serve certain commercial, industrial and governmental agency customer requests for renewable energy resources in South Dakota and Wyoming. To meet the renewable energy commitments under the new tariffs, we also received approval from the Wyoming Public Service Commission to build the Corriedale wind project, a 52.5 MW wind farm to be constructed near Cheyenne, Wyoming. The $79 million project is expected to be in service by year-end 2020. Supporting our renewable energy efforts in Colorado, in November 2019, we successfully commissioned Busch Ranch II, a 60 MW wind farm near Pueblo, Colorado, to provide renewable energy to our Colorado Electric utility.

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 emissions reduction targets. Federal legislation for both 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 on 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 supportive of our Electric Utilities. These operations are located at our utility-generating complexes and are physically integrated into our Electric Utility operations.

The Power Generation segment currently owns five power facilities, four of which are contracted with our affiliate Electric Utilities under 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 20 coal-fired, gas-fired and renewable generation projects since 1995 with aggregate project costs in excess of $2.1 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 surface coal mine is located immediately adjacent to our Gillette energy complex in northeastern Wyoming, where all five of our coal-fired power plants are located. We operate and own majority interests in four of our 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 gas-fired power plants. 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.

Expand utility operations through selective acquisitions of electric and gas utilities. The electric and natural gas utility industries have consolidated significantly over the past two decades and continue to consolidate. We have successfully acquired and integrated numerous utility systems since 2005, including two large, transformational acquisitions - the Aquila Transaction in 2008 and SourceGas Transaction in 2016. Through these acquisitions, we developed a scalable platform that simplifies the rapid integration of acquired utilities, providing significant benefits to both customers and shareholders. The company targets small to large utilities, including municipal and private utility systems, located primarily in geographies that are near to or contiguous with our existing utility service territories and can provide long-term value for both customers and shareholders. In the near-term, we do not expect to pursue large utility acquisitions, particularly given the high valuation multiples realized in recent utility transactions. As pipeline regulations continue to increase, we believe there will be more opportunities to purchase these smaller and more rural utility systems.

Grow our dividend. We are extremely proud of our track record of annual dividend increases for shareholders. In January 2020, our Board of Directors declared a quarterly dividend of $0.535 per share, equivalent to an annual dividend of $2.14 per share. This current annual equivalent rate of $2.14 per share, if declared and paid in 2020, will represent 50 consecutive years of annual dividend increases. 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 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 2019 company highlights discussed below.

Our discussion and analysis for the year ended December 31, 2019 compared to 2018, as well as discussion and analysis of the results of operations for the year ended December 31, 2018 compared to 2017 given segment reporting changes adopted by the Company in 2019, is included herein. For further discussion and analysis that remains unchanged for the year ended December 31, 2018 compared to 2017, 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, 2018, which was filed with the SEC on February 19, 2019.

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.

Results of Operations

Consolidated Summary and Overview

	For the Years Ended December 31,					
	2019		2018		2017	
(in millions, except per diluted share amounts)	Income	EPS	Income	EPS	Income	EPS
Net income from continuing operations available for common stock	$ 199.3	$ 3.28	$ 265.3	$ 4.78	$ 194.1	$ 3.52
Net (loss) from discontinued operations	—	—	(6.9)	(0.12)	(17.1)	(0.31)
Net income available for common stock	$ 199.3	$ 3.28	$ 258.4	$ 4.66	$ 177.0	$ 3.21

2019 Compared to 2018

The variance to the prior year included the following:

- Electric Utilities' adjusted operating income increased $4.4 million due to reduced purchased power capacity costs, increased rider revenues and the prior year Wyoming Electric PCA settlement partially offset by higher operating expenses driven by outside services and employee costs;
- Gas Utilities' adjusted operating income increased $4.7 million primarily due to new customer rates and rider revenues, customer growth and increased transport and transmission driven by increased volumes from new and existing customers partially offset by higher operating expenses driven by outside services and employee costs;
- Power Generation's adjusted operating income increased $2.2 million primarily due to higher revenue from increased wind MWh sold and higher PPA pricing partially offset by higher depreciation and property taxes from new wind assets;
- Mining's adjusted operating income decreased $3.7 million primarily due to lower tons sold driven by planned and unplanned generating facility outages partially offset by lower operating expenses;
- Corporate and Other expenses decreased $1.4 million primarily due to prior year expenses related to the oil and gas segment that were not reclassified to discontinued operations;
- A $20 million pre-tax non-cash impairment in 2019 of our investment in equity securities of a privately held oil and gas company;
- We expensed $5.4 million of development costs related to projects we no longer intend to construct; and
- Increased tax expense of $53 million primarily due to a prior year $73 million tax benefit resulting from legal entity restructuring partially offset by a prior year $4.0 million income tax expense associated with changes in the previously estimated impact of tax reform on deferred income taxes and current year $5.9 million federal PTCs and related state ITCs associated with new wind assets.

2018 Compared to 2017

The variance when comparing 2018 to 2017 included the following:

- Electric Utilities' adjusted operating income decreased $21.9 million due to TCJA benefits delivered to customers, the Wyoming Electric PCA settlement and higher operating expenses partially offset by increased rider revenues and favorable weather;
- Gas Utilities' adjusted operating income increased $0.1 million primarily due to colder winter weather, new customer rates, customer growth and increased transport and transmission offset by TCJA benefits delivered to customers and higher operating expenses;
- Power Generation's adjusted operating income decreased $4.1 million primarily due to a decrease in MWh sold and higher operating expenses;
- Mining's adjusted operating income increased $2.8 million primarily due to increase in price per ton sold and lower operating expenses;
- Corporate and Other expenses decreased $3.3 million primarily due to prior year acquisition costs; and
- Increased tax benefit of $97 million primarily due to a $73 million tax benefit resulting from legal entity restructuring and a reduction in the federal corporate income tax rate from 35% to 21% from the TCJA, effective January 1, 2018.

The following table summarizes select financial results by operating segment and details significant items (in thousands):

	For the Years Ended December 31,				
	2019	Variance	2018	Variance	2017
	(in thousands)				
Revenue					
Revenue	$ 1,885,669	$ (11,573)	$ 1,897,242	$ 83,721	$ 1,813,521
Intercompany eliminations	(150,769)	(7,795)	(142,974)	(9,719)	(133,255)
	$ 1,734,900	$ (19,368)	$ 1,754,268	$ 74,002	$ 1,680,266
Adjusted operating income (a)					
Electric Utilities	$ 160,297	$ 4,428	$ 155,869	$ (21,868)	$ 177,737
Gas Utilities	189,971	4,732	185,239	134	185,105
Power Generation	44,779	2,165	42,614	(4,076)	46,690
Mining	12,627	(3,713)	16,340	2,840	13,500
Corporate and Other	(1,632)	1,393	(3,025)	3,271	(6,296)
	406,042	9,005	397,037	(19,699)	416,736
Interest expense, net	(137,659)	2,316	(139,975)	(2,873)	(137,102)
Impairment of investment	(19,741)	(19,741)	—	—	—
Other income (expense), net	(5,740)	(4,560)	(1,180)	(3,288)	2,108
Income tax benefit (expense)	(29,580)	(53,247)	23,667	97,034	(73,367)
Income from continuing operations	213,322	(66,227)	279,549	71,174	208,375
(Loss) from discontinued operations, net of tax	—	6,887	(6,887)	10,212	(17,099)
Net income	213,322	(59,340)	272,662	81,386	191,276
Net income attributable to noncontrolling interest	(14,012)	208	(14,220)	22	(14,242)
Net income available for common stock	$ 199,310	$ (59,132)	$ 258,442	$ 81,408	$ 177,034

(a) In 2019, we changed our measure of segment performance to adjusted operating income, which impacted our segment disclosures for all periods presented. See Note 5 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for more information.

2019 Overview of Business Segments and Corporate Activity

Electric Utilities

- On December 13, 2019, Colorado Electric issued a request for proposals for its Renewable Advantage program, to potentially add up to 200 MW of renewable energy to its southern Colorado system. A competitive solicitation process for the addition of cost-effective, utility-scale renewable energy projects includes wind, solar and battery storage to supplement existing natural gas and wind generation power supplies Bidders have until February 15, 2020, to submit proposals, which will be reviewed by an independent evaluator overseen by the CPUC. Based on the outcome of the bidding process, projects would be placed in service no later than 2023.

- In July 2019, South Dakota Electric and Wyoming Electric received approvals for the Renewable Ready program and related jointly-filed CPCN to construct Corriedale. The wind project will be jointly owned by the two electric utilities to deliver renewable energy for large commercial, industrial and governmental agency customers. In November 2019, South Dakota Electric received approval from the SDPUC to increase the offering under the program by 12.5 MW. The two electric utilities also received a determination from the WPSC to increase the project to 52.5 MW. The $79 million project is expected to be in service by year-end 2020.

- On September 17, 2019, South Dakota Electric completed construction on the final 94-mile segment of a 175-mile electric transmission line from Rapid City, South Dakota, to Stegall, Nebraska. The first 48-mile segment was placed in service on July 25, 2018, and the second 33-mile segment was placed in service on November 20, 2018.

- Colorado Electric set a new all-time and summer peak load:

    - On July 19, 2019, Colorado Electric set a new all-time and summer peak load of 422 MW, exceeding the previous peak of 413 MW set in June 2018.

- Wyoming Electric set a new all-time and summer peak load, and also set a new winter peak load:

    - On July 19, 2019, Wyoming Electric set a new all-time and summer peak load of 265 MW, exceeding the previous peak of 254 MW set in July 2018.

    - On December 16, 2019, Wyoming Electric set a new winter peak load of 247 MW, exceeding the previous peak of 238 MW set in December 2018.

- Cooling degree days for the year ended December 31, 2019 were 14% higher than the normal compared to 29% higher than normal in 2018.

- Heating degree days for the year ended December 31, 2019 were 5% higher than normal compared to 3% higher than normal in 2018.

Gas Utilities

- Gas Utilities continued to consolidate utility jurisdictions within the States of Colorado, Nebraska, and Wyoming:

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

    - On February 1, 2019, Colorado Gas submitted a rate review with the CPUC to consolidate rates, tariffs and services of its two existing gas distribution territories. The rate review requested $2.5 million in new revenue to recover investments in safety, reliability and system integrity. Colorado Gas also requested a new rider mechanism to recover future safety and integrity investments in its system. On December 27, 2019, the ALJ issued a recommended decision denying the company's plan to consolidate rate territories and recommending a rate decrease. Colorado Gas has filed exceptions to the ALJ's recommended decision. A decision by the CPUC is expected by the end of March 2020. Legal consolidation was previously approved by the CPUC in late 2018 and completed in early 2019.

- On October 29, 2019, Nebraska Gas received approval from the NPSC to merge its two natural gas distribution companies. Legal consolidation was effective January 1, 2020, and a rate review is expected to be filed by mid-year 2020 to consolidate the rates, tariffs and services.

- On December 1, 2019, Wyoming Gas placed in service the $54 million, 35-mile Natural Bridge pipeline project to enhance supply reliability and delivery capacity for customers in central Wyoming. The new 12-inch steel pipeline interconnects from a supply point near Douglas, Wyoming, to facilities near Casper, Wyoming. The associated investment was included in the Wyoming Gas rate review completed in December 2019.

- Heating degree days at the Gas Utilities for the year ended December 31, 2019 were 5% higher than normal compared to 2% higher than normal in 2018.

Power Generation

- On November 26, 2019, Black Hills Electric Generation placed in service Busch Ranch II. Through a competitive bidding process, Black Hills Electric Generation was selected to deliver renewable energy under a 25-year PPA to Colorado Electric.

- On August 2, 2019, Black Hills Wyoming and Wyoming Electric jointly filed a request with FERC for approval of a new 60 MW PPA. The agreement would fulfill the capacity need for Wyoming Electric at the expiration of the current agreement on December 31, 2022. If approved, Black Hills Wyoming will continue to deliver 60 MW of energy to Wyoming Electric from its Wygen I power plant starting January 1, 2023, and for 20 additional years. On December 23, 2019, the Company filed a response to questions from the FERC and awaits a decision from FERC.

Mining

- In October 2019, negotiations were completed for the price reopener in the contract with the Wyodak power plant. Effective July 1, 2019, the new price was reset at $17.94 per ton with customary escalators, compared to the prior contract price of $18.25 per ton. The contract expires on December 31, 2022 and negotiations are underway to extend the contract.

Corporate and Other

- On October 3, 2019, we completed a public debt offering of $700 million in senior unsecured notes. Proceeds were used to repay the $400 million Corporate term loan due June 17, 2021, retire the $200 million 5.875% senior notes due July 15, 2020 and repay a portion of short-term debt.

- During the year ended December 31, 2019, we issued a total of 1.3 million shares of common stock for net proceeds of $99 million under our ATM equity offering program.

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

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 revenues less cost of 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 measure. Furthermore, this measure is not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance.

Electric Utilities

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

	2019	Variance	2018	Variance	2017
Revenue	$ 712,752	$ 1,301	$ 711,451	$ 6,801	$ 704,650
Total fuel and purchased power	268,297	(15,543)	283,840	9,477	274,363
Gross margin (non-GAAP)	444,455	16,844	427,611	(2,676)	430,287
Operations and maintenance	195,581	9,406	186,175	13,868	172,307
Depreciation and amortization	88,577	3,010	85,567	5,324	80,243
Total operating expenses	284,158	12,416	271,742	19,192	252,550
Adjusted operating income [(a)]	$ 160,297	$ 4,428	$ 155,869	$ (21,868)	$ 177,737

(a) Due to the changes in our segment disclosures discussed in Note 5 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K, Electric Utilities Adjusted operating income was revised for the years ended December 31, 2018 and December 31, 2017 which resulted in an increase of $6.4 million and $7.1 million, respectively.

2019 Compared to 2018

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

	(in millions)
Reduction in purchased power capacity costs	$ 6.5
Prior year Wyoming Electric PCA Stipulation settlement	3.7
Rider recovery	3.1
Increased commercial and industrial demand	1.9
Weather	0.2
Other	1.4
Total increase in Gross margin (non-GAAP)	$ 16.8

Operations and maintenance expense increased primarily due to $4.7 million of higher employee costs and $2.9 million of higher outside services expenses. Various other expenses comprise the remainder of the increase compared to the prior year.

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

2018 Compared to 2017

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

	(in millions)
TCJA revenue reserve	$ (22.3)
Wyoming Electric PCA Stipulation settlement	(2.6)
Other	(1.4)
Horizon Point shared facility revenue [(a)]	9.8
Rider recovery	5.1
Weather	3.6
Power Marketing, transmission and Tech Services	3.5
Residential customer growth	1.6
Total increase (decrease) in Gross margin (non-GAAP)	$ (2.7)

(a) Horizon Point shared facility revenue was offset by facility expenses at our operating segments and had no impact on consolidated results.

Operations and maintenance expense increased primarily due to $4.5 million of higher facility costs, $4.1 million of higher outside services expenses, $3.6 million of higher employee costs, and $1.0 million of higher property taxes due to a higher asset base.

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

	For the year ended December 31,		
Contracted power plant fleet availability [(a)]	2019	2018	2017
Coal-fired plants [(b)]	92.1%	93.9%	88.9%
Natural gas fired plants and Other plants [(c)]	87.9%	96.4%	96.1%
Wind	95.6%	96.9%	93.3%
Total availability	89.9%	95.6%	93.6%
Wind capacity factor	38.7%	39.2%	36.7%

(a) Availability and wind capacity factor are calculated using a weighted average based on capacity of our generating fleet.
(b) 2019 included planned outages at Neil Simpson II and Wygen III and unplanned outages at Wyodak Plant and Wygen III.
(c) 2019 included planned outages at Neil Simpson CT and Lange CT.

Gas Utilities

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

	2019	Variance	2018	Variance	2017
Revenue:					
Natural gas - regulated	$ 932,111	$ (10,813)	$ 942,924	$ 77,093	$ 865,831
Other - non-regulated services	77,919	(4,464)	82,383	584	81,799
Total revenue	1,010,030	(15,277)	1,025,307	77,677	947,630
Cost of natural gas sold:					
Natural gas - regulated	406,643	(35,887)	442,530	61,271	381,259
Other - non-regulated services	19,255	(368)	19,623	(8,721)	28,344
Total cost of sales	425,898	(36,255)	462,153	52,550	409,603
Gross margin (non-GAAP)	584,132	20,978	563,154	25,127	538,027
Operations and maintenance	301,844	10,363	291,481	22,291	269,190
Depreciation and amortization	92,317	5,883	86,434	2,702	83,732
Total operating expenses	394,161	16,246	377,915	24,993	352,922
Adjusted operating income	$ 189,971	$ 4,732	$ 185,239	$ 134	$ 185,105

2019 Compared to 2018

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

	(in millions)
New rates	$ 16.2
Customer growth - distribution	5.2
Increased transport and transmission	2.6
Weather	(2.2)
Decreased mark-to-market on non-utility natural gas commodity contracts	(3.3)
Other	2.5
Total increase in Gross margin (non-GAAP)	$ 21.0

Operations and maintenance expense increased primarily due to $5.5 million of higher outside services expenses, $1.2 million higher employee costs and $2.0 million of higher property taxes due to a higher asset base driven by prior and current year capital expenditures. Various other expenses comprise the remainder of the increase compared to the prior year.

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

2018 Compared to 2017

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

		(in millions)
Weather [(a)]	$	13.8
New rates		10.7
Customer growth - distribution		5.2
Increased mark-to-market on non-utility natural gas commodity contracts		4.0
Increased transport and transmission		3.6
Natural gas volumes sold		3.2
Non-utility - Choice Gas, Tech Services and appliance repair		2.7
Other		2.4
TCJA revenue reserve		(20.5)
Total increase (decrease) in Gross margin (non-GAAP)	$	25.1

(a) Heating degree days at the Gas Utilities for the year ended December 31, 2018 were 2% higher than normal compared to 10% lower than normal in 2017.

Operations and maintenance expense increased primarily due to $11.8 million of higher employee costs, $4.7 million of higher facility costs, $4.0 million of higher outside services expenses and $2.1 million of higher bad debt expense driven by an increase in revenues.

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

Power Generation

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

	2019	Variance	2018	Variance	2017
Revenue	$ 101,258	$ 8,807	$ 92,451	$ (2,169)	$ 94,620
Total fuel	9,059	467	8,592	(748)	9,340
Operations and maintenance	28,429	3,294	25,135	2,093	23,042
Depreciation and amortization	18,991	2,881	16,110	562	15,548
Total operating expenses	56,479	6,642	49,837	1,907	47,930
Adjusted operating income [(a)]	$ 44,779	$ 2,165	$ 42,614	$ (4,076)	$ 46,690

(a) Due to the changes in our segment disclosures discussed in Note 5 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K, Power Generation Adjusted operating income was revised for the years ended December 31, 2018 and December 31, 2017 which resulted in a decrease of $(5.7) million and $(6.5) million, respectively.

2019 Compared to 2018

Revenue increased in the current year due to increased wind MWh sold and higher PPA prices. Operating expenses increased in the current year primarily due to higher depreciation and property taxes from new wind assets.

2018 Compared to 2017

Revenue decreased in 2018 due to a decrease in MWh sold, primarily from a planned outage at Wygen I. Operating expenses increased due to higher maintenance expenses primarily related to outage costs at Wygen I and higher depreciation.

	For the year ended December 31,		
Contracted power plant fleet availability [(a)]	2019	2018	2017
Coal-fired plant [(b)]	94.5%	85.8%	96.9%
Natural gas-fired plants	98.6%	99.4%	99.2%
Wind [(c)]	90.6%	N/A	N/A
Total availability	95.0%	95.9%	98.6%
Wind capacity factor [(c)]	23.5%	N/A	N/A

(a) Availability and wind capacity factor are calculated using a weighted average based on capacity of our generating fleet.
(b) Wygen I experienced a planned outage in 2018
(c) Change from 2018 to 2019 is driven by Black Hills Electric Generation's acquisition of new wind assets.

Mining

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

	2019	Variance	2018	Variance	2017
Revenue	$ 61,629	$ (6,404)	$ 68,033	$ 1,412	$ 66,621
Operations and maintenance	40,032	(3,696)	43,728	(1,154)	44,882
Depreciation, depletion and amortization	8,970	1,005	7,965	(274)	8,239
Total operating expenses	49,002	(2,691)	51,693	(1,428)	53,121
Adjusted operating income	$ 12,627	$ (3,713)	$ 16,340	$ 2,840	$ 13,500

The following table provides certain operating statistics for the Mining segment (in thousands):

	2019	2018	2017
Tons of coal sold	3,716	4,085	4,183
Cubic yards of overburden moved	8,534	8,970	9,018
Coal reserves at year-end (in tons)	185,448	189,164	194,909
Revenue per ton	$ 15.94	$ 16.11	$ 15.93

2019 Compared to 2018

Current year revenue decreased primarily due to 9% fewer tons sold driven primarily by planned and unplanned generation facility outages at the Wyodak Plant. Operating expenses decreased primarily due to lower royalties and production taxes on decreased revenues and lower fuel, labor, and major maintenance expenses.

2018 Compared to 2017

Revenue increased primarily due to a 1% increase in price per ton sold. Current year revenue is also reflective of lease and rental revenue, previously reported in Other income, net. Operating expenses decreased primarily due to lower major maintenance expenses.

Corporate and Other

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

(in thousands)	2019	Variance	2018	Variance	2017
Adjusted operating (loss) [(a)]	$ (1,632)	$ 1,393	$ (3,025)	$ 3,271	$ (6,296)

(a) Due to the changes in our segment disclosures discussed in Note 5 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K, Corporate and Other Adjusted operating (loss) was revised for the years ended December 31, 2018 and December 31, 2017 which resulted in a decrease of $(0.7) million and $(0.6) million, respectively.

2019 Compared to 2018

The variance in Adjusted operating (loss) was primarily due to prior year expenses related to the oil and gas segment that were not reclassified to discontinued operations.

2018 Compared to 2017

The variance in Adjusted operating (loss) was primarily due to prior year acquisition costs.

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

(in thousands)	2019	Variance	2018	Variance	2017
Interest expense, net	$ (137,659)	$ 2,316	$ (139,975)	$ (2,873)	$ (137,102)
Impairment of investment	(19,741)	(19,741)	—	—	—
Other income (expense), net	(5,740)	(4,560)	(1,180)	(3,288)	2,108
Income tax benefit (expense)	(29,580)	(53,247)	23,667	97,034	(73,367)

2019 Compared to 2018

Impairment of Investment

For the year ended December 31, 2019, we recorded a pre-tax non-cash write-down of $20 million in our investment in equity securities of a privately held oil and gas company. The impairment was triggered by a deterioration in earnings performance of the privately held oil and gas company and an adverse change in future natural gas prices. See Note 1 of the Notes to Consolidated Financial Statements for additional details.

Other Income (Expense)

For the year ended December 31, 2019, we expensed $5.4 million of development costs related to projects we no longer intend to construct.

Income Tax Benefit (Expense)

The increase in tax expense was primarily due to a prior year $73 million tax benefit resulting from legal entity restructuring partially offset by:

- A prior year $(4.0) million income tax expense associated with changes in the previously estimated impact of tax reform on deferred income taxes;
- Current year $3.8 million of federal PTCs and $2.1 million of related state ITCs associated with new wind assets;
- A current year $1.9 million tax benefit from increased repair activity in flow-through regulatory jurisdictions;
- A current year $1.4 million tax benefit for incremental excess deferred tax amortization related to tax reform; and
- A current year $3.4 million tax benefit from a federal tax loss carry-back claim including interest. We identified certain qualified expenses that extend beyond the typical two-year carry-back period.

2018 Compared to 2017

Other Income (Expense)

The variance in Other income (expense), net was primarily due to the presentation change of non-service pension costs to Other income (expense) in 2018, previously reported in Operations and maintenance.

Income Tax Benefit (Expense)

The variance in Income tax benefit (expense) was primarily due to a $73 million tax benefit in 2018 resulting from legal entity restructuring and the reduction in the federal corporate income tax rate from 35% to 21% from the TCJA, effective January 1, 2018, partially offset by a $(4.0) million income tax expense associated with changes in the previously estimated impact of tax reform on deferred income taxes.

Liquidity and Capital Resources

OVERVIEW

Our company requires significant cash to support and grow our businesses. Our predominant source of cash is from our operations and supplemented with corporate financings. 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.

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

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

Financial Position Summary	2019	2018
Cash and cash equivalents	$ 9,777	$ 20,776
Restricted cash and equivalents	$ 3,881	$ 3,369
Notes payable	$ 349,500	$ 185,620
Short-term debt, including current maturities of long-term debt	$ 5,743	$ 5,743
Long-term debt [(a)]	$ 3,140,096	$ 2,950,835
Stockholders' equity	$ 2,362,123	$ 2,181,588
Ratios		
Long-term debt ratio	57%	57%
Total debt ratio	60%	59%

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

Significant Factors Affecting Liquidity

Although we believe we have sufficient resources to fund our cash requirements, there are many factors with the potential to influence our cash flow position, including weather seasonality, commodity prices, significant capital projects and acquisitions, requirements imposed by state and federal agencies and economic market conditions. We have implemented risk mitigation programs, where possible, to stabilize cash flow. However, the potential for unforeseen events affecting cash needs will continue to exist.

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, 2019, we had sufficient liquidity to cover collateral that could be required to be posted under these contracts.

Weather Seasonality, Commodity Pricing and Associated Hedging Strategies

We manage liquidity needs through hedging activities, primarily in connection with seasonal needs of our utility operations (including seasonal peaks in fuel requirements), interest rate movements and commodity price movements.

Utility Factors

Our cash flows, and in turn liquidity needs in many of our regulated jurisdictions, can be subject to fluctuations in weather and commodity prices. Since weather conditions are uncontrollable, we have implemented commission-approved natural gas hedging and storage programs in many of our regulated jurisdictions to mitigate significant changes in natural gas commodity pricing. We target hedging a percentage of our forecasted natural gas supply consumption using options, futures, basis swaps and physical fixed price purchases.

Interest Rates

Some of our debt instruments have a variable interest rate component which can change significantly depending on the economic climate. We do not have any interest rate swap agreements at December 31, 2019; 90% of our interest rate exposure has been mitigated through fixed interest rates.

Federal and State Regulations

We are structured as a utility holding company which owns several regulated utilities. Within this structure, we are subject to various regulations by our commissions that can influence our liquidity. As an example, the issuance of debt by our regulated subsidiaries and the use of our utility assets as collateral generally require prior approval of the state regulators in the state in which the utility assets are located. Furthermore, as a result of our holding company structure, our right as a common shareholder to receive assets of any of our direct or indirect subsidiaries upon a subsidiary's liquidation or reorganization is subordinate to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities and guarantee holders.

CASH GENERATION AND CASH REQUIREMENTS

Cash Generation

Our primary sources of cash are generated from operating activities, our five-year Revolving Credit Facility expiring in 2023, our CP Program, our ATM equity offering program and our ability to access the public and private capital markets through debt and equity securities offerings when necessary.

Cash Collateral

Under contractual agreements and exchange requirements, BHC or its subsidiaries have collateral requirements, which if triggered, require us to post cash collateral with the counterparty to meet these obligations. The cash collateral we were required to post at December 31, 2019 was not material.

DEBT, EQUITY AND LIQUIDITY

Debt

Revolving Credit Facility and CP Program

On July 30, 2018, we amended and restated our corporate Revolving Credit Facility, maintaining total commitments of $750 million and extending the term through July 30, 2023 with two one-year extension options (subject to consent from lenders). This facility is similar to the former revolving credit facility, which includes an accordion feature that allows us, with the consent of the administrative agent, the issuing agents and each bank increasing or providing a new commitment, to increase total commitments up to $1.0 billion. Borrowings continue to be available under a base rate or various Eurodollar rate options. See Note 7 of our Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for more information.

We have a $750 million, unsecured CP Program that is backstopped by the Revolving Credit Facility. Amounts outstanding under the Revolving Credit Facility and the CP Program, either individually or in the aggregate, cannot exceed $750 million. See Note 7 of our Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for more information.

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, 2019	Letters of Credit at December 31, 2019	Available Capacity at December 31, 2019
Revolving Credit Facility and CP Program	July 30, 2023	$ 750	$ 350	$ 30	$ 370

The weighted average interest rate on short-term borrowings at December 31, 2019 was 2.03%. Short-term borrowing activity for the twelve months ended December 31, 2019 was:

	(dollars in millions)
Maximum amount outstanding - short-term borrowing (based on daily outstanding balances)	$ 357
Average amount outstanding - short-term borrowing (based on daily outstanding balances)	$ 187
Weighted average interest rates - short-term borrowing	2.47%

The Revolving Credit Facility contains customary affirmative and negative covenants, such as limitations on certain liens, restrictions on certain transactions, and maintenance of a certain Consolidated Indebtedness to Capitalization Ratio. We were in compliance with these covenants as of December 31, 2019. See Note 7 of our Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for more information.

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.

Cross-Default Provisions

Our $7 million Corporate term loan contains cross-default provisions that could result in a default under such agreements if BHC or its material subsidiaries failed to make timely payments of debt obligations or triggered other default provisions under any debt agreement totaling, in the aggregate principal amount of $50 million or more that permits the acceleration of debt maturities or mandatory debt prepayment. Our Revolving Credit Facility contains the same provisions and the threshold principal amount is $50 million.

The Revolving Credit Facility prohibits us from paying cash dividends if we are in default or if paying dividends would cause us to be in default.

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 (2.210% at December 31, 2019). 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.

At December 31, 2019, money pool balances included (in thousands):

Subsidiary		Borrowings From Money Pool Outstanding
BHSC	$	148,041
South Dakota Electric		57,585
Wyoming Electric		37,993
Total Money Pool borrowings from Parent	$	243,619

Equity

Shelf Registration

We have an effective automatic 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 2020. 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, 2019, we had approximately 61 million shares of common stock outstanding and no shares of preferred stock outstanding.

ATM

In 2019, we issued a total of 1,328,332 shares of common stock under the ATM for proceeds of $99 million, net of $1.2 million in issuance costs. As of December 31, 2019, all shares were settled.

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.

On January 29, 2020, our Board of Directors declared a quarterly dividend of $0.535 per share, equivalent to an annual dividend rate of $2.14 per share. The table below provides our historical three-year dividend payout ratio and dividends paid per share:

	2019	2018	2017
Dividend Payout Ratio	63%	40%	50%
Dividends Per Share	$2.05	$1.93	$1.81

Our three-year compound annualized dividend growth rate was 6.9% and all dividends were paid out of available operating cash flows.

Dividend Restrictions

As a utility holding company which owns several regulated utilities, we are subject to various regulations that could influence our liquidity. Our utilities in Arkansas, Colorado, Iowa, Kansas and Nebraska have regulatory agreements in which they cannot pay dividends if they have issued debt to third parties and the payment of a dividend would reduce their equity ratio to below 40% of their total capitalization; and neither BHSC nor its utility subsidiaries can extend credit to the Company except in the ordinary course of business and upon reasonable terms consistent with market terms. The use of our utility assets as collateral generally requires the prior approval of the state regulators in the state in which the utility assets are located. Additionally, our utility subsidiaries may generally be limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act.

As a result of our holding company structure, our right as a common shareholder to receive assets from any of our direct or indirect subsidiaries upon a subsidiary's liquidation or reorganization is junior to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities and guarantee holders. See additional information in Note 6 of our Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

Our credit facilities and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be deemed to have occurred if we did not comply with certain financial or other covenants. See additional information in Note 7 of our Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

Covenants within Wyoming Electric's financing agreements require Wyoming Electric to maintain a debt to capitalization ratio of no more than 0.60 to 1.00. As of December 31, 2019, we were in compliance with these covenants.

Financing Activities

Financing activities in 2019 consisted of the following:

- We issued a total of 1.3 million shares of common stock under the ATM equity offering program for proceeds of $99 million, net of $1.2 million in issuance costs.

- On October 3, 2019, we completed a public debt offering of $700 million principal amount in senior unsecured notes. The debt offering consisted of $400 million of 3.05% 10-year senior notes due October 15, 2029, and $300 million of 3.875% 30-year senior notes due October 15, 2049. Proceeds were used to repay the $400 million Corporate term loan due June 17, 2021, retire the $200 million 5.875% senior notes due July 15, 2020, and repay a portion of short-term debt.

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

- Short-term borrowings from our Revolving Credit Facility and CP Program.

<u>**Future Financing Plans**</u>

We anticipate the following financing activities in 2020:

- Renew our shelf registration and ATM;

- Continued equity issuance under the ATM or assess other equity issuance options;

- Refinance a portion of short-term borrowings held through the Revolving Credit Facility and CP Program to long-term debt; and

- Continue to assess debt and equity needs to support our capital expenditure plan.

CASH FLOW ACTIVITIES

The following table summarizes our cash flows (in thousands):

		2019		2018		2017
Cash provided by (used in)						
Operating activities	$	505,513	$	488,811	$	428,261
Investing activities	$	(816,210)	$	(465,849)	$	(317,118)
Financing activities	$	300,210	$	(17,057)	$	(108,695)

<u>2019 Compared to 2018</u>

Operating Activities:

Net cash provided by operating activities was $17 million higher than in 2018. The variance to the prior year was primarily attributable to:

- Cash earnings (income from continuing operations plus non-cash adjustments) were $37 million higher than prior year driven primarily by higher margins at our Electric and Gas Utilities;

- Net outflows from operating assets and liabilities were $25 million higher than prior year, primarily attributable to:

  - Cash outflows increased by approximately $40 million as a result of changes in accounts payable and accrued liabilities, driven by the impact of higher outside services, employee costs and other working capital requirements;

  - Cash inflows increased by approximately $59 million compared to the prior year primarily as a result of lower accounts receivable driven by lower pass-through revenues reflecting lower commodity prices; and

  - Cash inflows decreased by approximately $44 million primarily as a result of changes in our current regulatory liabilities due to the TCJA tax rate change that has subsequently been returned to customers and from changes in our current regulatory assets driven by lower fuel cost adjustments and the impact of lower commodity prices; and

- Cash outflows decreased approximately $5.5 million due to the absence of operating activities of discontinued operations in 2019.

Investing Activities:

Net cash used in investing activities was $816 million in 2019, compared to net cash used in investing activities of $466 million in 2018 for a variance of $350 million. This variance was primarily due to:

- Capital expenditures of approximately $818 million in 2019 compared to $458 million in 2018. The $361 million increase from the prior year was due to higher capital expenditures driven by higher programmatic safety, reliability and integrity spending at our Electric and Gas Utilities segments, the Corriedale Wind Energy Project at our Electric Utilities segment, construction of the final segment of the 175-mile transmission line from Rapid City, South Dakota, to Stegall, Nebraska, at our Electric Utilities segment, the 35-mile Natural Bridge pipeline project at our Gas Utilities segment, and construction of Busch Ranch II at our Power Generation segment; and

- Net cash used in investing activities decreased $4.0 million due to prior year activities associated with divesting of our oil and gas segment.

Financing Activities:

Net cash provided by financing activities was $300 million in 2019 as compared to net cash used by financing activities of $17 million in 2018, an increase of $317 million due to the following:

- Increase of $539 million due to issuances of long and short-term debt in excess of required maturities that were used to fund our capital program

- Decrease of $199 million in common stock issued primarily due to prior year gross proceeds of approximately $299 million from the Equity Unit conversion partially offset by current year net proceeds of $99 million through our ATM equity offering program;

- Cash dividends on common stock of $125 million were paid in 2019 compared to $107 million paid in 2018; and

- Cash outflows for other financing activities increased by approximately $5.5 million driven primarily by current year financing costs incurred in the October 3, 2019 debt transaction.

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 Key Elements of our Business Strategy above in Item 7 - Executive Summary and Business Strategy for forecasted capital expenditure requirements.

A significant portion of our capital expenditures relates to safety, reliability and integrity assets benefiting customers that may be included in utility rate base and can be recovered from our utility customers following regulatory approval. Those capital expenditures also earn a rate of return authorized by the commissions in the jurisdictions in which we operate.

Historical Capital Requirements

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

	2019	2018	2017
Property additions: [a]			
Electric Utilities [b]	$ 222,911	$ 152,524	$ 138,060
Gas Utilities [c]	512,366	288,438	184,389
Power Generation [d]	85,346	30,945	1,864
Mining	8,430	18,794	6,708
Corporate and Other	20,702	11,723	6,668
Capital expenditures before discontinued operations	849,755	502,424	337,689
Discontinued operations	—	2,402	23,222
Total capital expenditures	849,755	504,826	360,911
Common stock dividends	124,647	106,591	96,744
Maturities/redemptions of long-term debt	905,743	854,743	105,743
Total capital requirements	$ 1,880,145	$ 1,466,160	$ 563,398

(a) Includes accruals for property, plant and equipment as disclosed in Note 17 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

(b) Current year capital expenditures at our Electric Utilities segment increased due to higher programmatic safety, reliability and integrity spending, the Corriedale wind project and construction of the final segment of the 175-mile transmission line from Rapid City, South Dakota, to Stegall, Nebraska.

(c) Current year capital expenditures at our Gas Utilities segment increased due to higher programmatic safety, reliability and integrity spending and the 35-mile Natural Bridge pipeline project.

(d) Current year capital expenditures at our Power Generation segment increased due to construction of Busch Ranch II.

CREDIT RATINGS AND COUNTERPARTIES

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. BHC notes 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, 2019:

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

(a) On February 28, 2019, S&P affirmed our BBB+ rating and maintained a Stable outlook.
(b) On December 20, 2019, Moody's affirmed our Baa2 rating and maintained a Stable outlook.
(c) On August 29, 2019, Fitch affirmed our BBB+ rating and maintained a Stable outlook.

Certain of our fees and our interest rates under various bank credit agreements 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 downgraded our senior unsecured debt, we will be required to pay higher fees and interest rates under these bank credit agreements.

The following table represents the credit ratings of South Dakota Electric at December 31, 2019:

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

(a) On April 30, 2019, S&P affirmed A rating.
(b) On December 20, 2019, Moody's affirmed A1 rating.
(c) On August 29, 2019, Fitch affirmed 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.

CONTRACTUAL OBLIGATIONS AND OTHER COMMITMENTS

Contractual Obligations

In addition to our capital expenditure programs, we have contractual obligations and other commitments that will need to be funded in the future. The following information summarizes our cash obligations and commercial commitments at December 31, 2019. Actual future obligations may differ materially from these estimated amounts (in thousands):

	Payments Due by Period						
Contractual Obligations	2020	2021	2022	2023	2024	Thereafter	Total
Long-term debt[a]	$ 5,743	$ 8,435	$ —	$ 525,000	$ 2,855	$ 2,635,000	$ 3,177,033
Interest payments [a]	131,859	131,842	131,756	131,756	109,390	1,273,648	1,910,251
Unconditional purchase obligations[b]	181,773	159,827	134,018	105,583	54,098	126,147	761,446
Lease obligations[c]	1,144	991	869	844	724	2,009	6,581
AROs [d]	330	231	144	33	9,362	54,105	64,205
Employee benefit plans[e]	18,921	19,678	19,736	19,944	19,896	35,580	133,755
CP Program	349,500	—	—	—	—	—	349,500
Total contractual cash obligations[f]	$ 689,270	$ 321,004	$ 286,523	$ 783,160	$ 196,325	$ 4,126,489	$ 6,402,771

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(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, 2019.

(b) Unconditional purchase obligations include the energy and capacity costs associated with our PPAs, capacity and certain transmission, gas transportation and storage agreements. The energy charges under the PPAs are variable costs, which for purposes of estimating our future obligations, were based on costs incurred during 2019 and price assumptions using existing prices at December 31, 2019. Our transmission obligations are based on filed tariffs as of December 31, 2019.

(c) Includes leases associated with several office and operating facilities, communication tower sites, equipment and materials storage.

(d) Represents estimated payments for AROs associated with long-lived assets primarily related to retirement and reclamation of natural gas pipelines, mining sites, wind farms and an evaporation pond. See Notes 1 and 8 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

(e) Represents estimated employer contributions to the Defined Benefit Pension Plan, the Non-Pension Defined Benefit Postretirement Healthcare Plan and the Supplemental Non-Qualified Defined Benefit Plans through the year 2029 as discussed in Note 18 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

(f) Amounts in the table exclude: (1) any obligation that may arise from our derivatives, including commodity related contracts that have a negative fair value at December 31, 2019. These amounts have been excluded as it is impractical to reasonably estimate the final amount and/or timing of any associated payments; (2) a portion of our gas purchases are hedged. These hedges are in place to reduce our customers' underlying exposure to commodity price fluctuations. The impact of these hedges is not included in the above table; (3) our $4.2 million liability for unrecognized tax benefits in accordance with accounting guidance for uncertain tax positions as discussed in Note 15 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

Our Gas Utilities have commitments to purchase physical quantities of natural gas under contracts indexed to various forward natural gas price curves. In addition, a portion of our gas purchases are purchased under evergreen contracts and therefore, for purposes of this disclosure, are carried out for 60 days. As of December 31, 2019, we are committed to purchase 3.7 million MMBtu, 3.7 million MMBtu, and 1.8 million MMBtu in each of the years from 2020 to 2022, respectively.

Off-Balance Sheet Commitments

We have entered into various off-balance sheet commitments in the form of guarantees and letters of credit.

Guarantees

We provide various guarantees supporting certain of our subsidiaries under specified agreements or transactions. For more information on these guarantees, see Note 20 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

Letters of Credit

Letters of credit reduce the borrowing capacity available on our corporate Revolving Credit Facility. For more information on these letters of credit, see Note 7 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

Critical Accounting Policies Involving Significant Accounting Estimates

We prepare our consolidated financial statements in conformity with GAAP. In many cases, the accounting treatment of a particular transaction is specifically dictated by GAAP and does not require management's judgment in application. There are also areas which require management's judgment in selecting among available GAAP alternatives. We are required to make certain estimates, judgments and assumptions that we believe are reasonable based upon the information available. 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 the Consolidated Financial Statements in this Annual Report on Form 10-K.

Regulation

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

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

To some degree, each of our Electric and Gas Utilities are permitted to recover certain costs (such as increased fuel and purchased power costs) outside of a base rate review. To the extent we are able to pass through such costs to our customers, and a state public utility commission subsequently determines that such costs should not have been paid by the customers, we may be required to refund such costs. Any such costs not recovered through rates, or any such refund, could adversely affect our results of operations, financial position or cash flows.

As of December 31, 2019 and 2018, we had total regulatory assets of $271 million and $284 million, respectively, and total regulatory liabilities of $537 million and $541 million, respectively. See Note 13 of the Notes to the 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 our testing date with our financial planning process.

Accounting standards for testing goodwill for impairment require a two-step process be performed to analyze whether or not goodwill has been impaired. Goodwill is tested for impairment at the reporting unit level. The first step of this test, used to identify potential impairment, compares the estimated fair value of a reporting unit with its carrying amount, including goodwill. If the carrying amount exceeds fair value under the first step, then the second step of the impairment test is performed to measure the amount of any impairment loss.

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 segment management 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 in the fourth quarter of 2019. 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, as well as other improved efficiency and cost reduction initiatives. 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, 2019, 2018, and 2017, there were no impairment losses recorded. At December 31, 2019, the fair value substantially exceeded the carrying value at all reporting units.

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

Pension and Other Postretirement Benefits

As described in Note 18 of the Notes to the 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 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.

The 2020 pension benefit cost for our non-contributory funded pension plan is expected to be $10.2 million compared to $2.1 million in 2019. The increase in pension benefit cost is driven primarily by a decrease in the discount rate and lower expected return on assets.

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	2019 Increase/(Decrease) PBO/APBO [(a)]	2020 Increase/(Decrease) Expense - Pretax
Pension			
Discount rate [(b)]	+/- 0.5	(28,998)/31,912	(3,965)/4,311
Expected return on assets	+/- 0.5	N/A	(2,036)/2,036
OPEB			
Discount rate [(b)]	+/- 0.5	(2,836)/3,095	90/116
Expected return on assets	+/- 0.5	N/A	(39)/39

(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, 2019, 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, 2019, the Company has amortized $6.5 million of regulatory liability associated with TCJA related items. The portion that was eligible for amortization under the average rate assumption method in 2019, 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 15 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

Market Risk Disclosures

Our market risk disclosures are detailed in Note 9 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K, with additional information provided in the following paragraphs.

Our exposure to the market risks detailed in Note 9 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K is also affected by other factors including the size, duration and composition of our energy portfolio, the absolute and relative levels of interest rates and commodity prices, the volatility of these prices and rates and the liquidity of the related interest rate and commodity markets.

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, appropriate or desirable, to review our business and credit activities and to ensure that these activities are conducted within the authorized policies.

Electric and Gas Utilities

We produce, purchase and distribute power in four states, and purchase and distribute natural gas in six states. 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 "true-up" 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 utility commissions. See additional information in Note 9 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

Wholesale Power

A potential risk related to power sales is the price risk arising from the sale of wholesale 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.

Financing Activities

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, 2019, we had no interest rate swaps in place. As discussed in Item 7 - Liquidity and Capital Resources, 90% of our variable interest rate exposure has been mitigated through issuing fixed rate debt.

Further details of past swap agreements are set forth in Note 9 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

Credit Risk

Our credit risk disclosures are detailed in Note 9 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K, with additional information provided below.

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. In addition, our Executive Risk Committee, which includes senior executives, meets on a regular basis to review our credit activities and to monitor compliance with the adopted policies.

New Accounting Pronouncements

See Note 1 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for information on new accounting standards adopted in 2019 or pending adoption.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2019, 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, 2019.

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, 2019. Deloitte & Touche LLP's report on Black Hills Corporation's internal control over financial reporting is included herein.

Black Hills Corporation

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Black Hills Corporation and subsidiaries (the "Company") as of December 31, 2019 and 2018, the related consolidated statements of income, comprehensive income, cash flows, and equity, for each of the three years in the period ended December 31, 2019, and the related notes and the schedule listed in the Index at Item 15 (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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, 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, 2019, based on criteria established in *Internal Control--Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 14, 2020, 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 Note 1 and Note 13 to the financial statements

Critical Audit Matter Description

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

Rates are regulated on a state-by-state basis by the relevant state regulatory commissions based on an analysis of the costs, as reviewed and approved in a regulatory proceeding. Rate regulation is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. Decisions to be made by the Commissions in the future will impact the accounting for regulated operations, including decisions about the amount of allowable costs and return on invested capital included in rates and any refunds that may be required. While the Company has indicated its regulatory assets are probable of recovery in current rates or in future proceedings, there is a risk that the Commissions will not judge all costs to have been prudently incurred or that the rate regulation process in which rates are determined will 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) a refund or a future reduction 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 evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.
- 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 precedence of the Commissions' treatment of similar costs under similar circumstances. We evaluated the external information and compared to the Company's recorded regulatory asset and liability balances for completeness and for any evidence that might contradict management's assertions.
- We obtained 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 a future reduction in rates.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 14, 2020

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Black Hills Corporation and subsidiaries (the "Company") as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements and financial statement schedule of the Company as of and for the year ended December 31, 2019, and our report dated February 14, 2020 expressed an unqualified opinion on those consolidated financial statements and financial statement schedule.

Basis for Opinion

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 14, 2020

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

Year ended	December 31, 2019	December 31, 2018	December 31, 2017
	(in thousands, except per share amounts)		
Revenue	$ 1,734,900	$ 1,754,268	$ 1,680,266
Operating expenses:			
Fuel, purchased power and cost of natural gas sold	570,829	625,610	563,288
Operations and maintenance	495,994	481,706	454,605
Depreciation, depletion and amortization	209,120	196,328	188,246
Taxes - property and production	52,915	51,746	51,578
Other operating expenses	—	1,841	5,813
Total operating expenses	1,328,858	1,357,231	1,263,530
Operating income	406,042	397,037	416,736
Other income (expense):			
Interest charges -			
Interest expense incurred net of amounts capitalized (including amortization of debt issuance costs, premiums and discounts)	(145,847)	(143,720)	(140,533)
Allowance for funds used during construction - borrowed	6,556	2,104	2,415
Interest income	1,632	1,641	1,016
Allowance for funds used during construction - equity	472	619	2,321
Impairment of investment	(19,741)	—	—
Other income (expense), net	(6,212)	(1,799)	(213)
Total other income (expense)	(163,140)	(141,155)	(134,994)
Income before income taxes	242,902	255,882	281,742
Income tax benefit (expense)	(29,580)	23,667	(73,367)
Income from continuing operations	213,322	279,549	208,375
Net (loss) from discontinued operations	—	(6,887)	(17,099)
Net income	213,322	272,662	191,276
Net income attributable to noncontrolling interest	(14,012)	(14,220)	(14,242)
Net income available for common stock	$ 199,310	$ 258,442	$ 177,034
Amounts attributable to common shareholders:			
Net income from continuing operations	$ 199,310	$ 265,329	$ 194,133
Net (loss) from discontinued operations	—	(6,887)	(17,099)
Net income available for common stock	$ 199,310	$ 258,442	$ 177,034
Earnings (loss) per share of common stock, Basic -			
Earnings from continuing operations	$ 3.29	$ 4.88	$ 3.65
(Loss) from discontinued operations	—	(0.13)	(0.32)
Total earnings per share of common stock, Basic	$ 3.29	$ 4.75	$ 3.33
Earnings (loss) per share of common stock, Diluted -			
Earnings from continuing operations	$ 3.28	$ 4.78	$ 3.52
(Loss) from discontinued operations	—	(0.12)	(0.31)
Total earnings per share of common stock, Diluted	$ 3.28	$ 4.66	$ 3.21
Weighted average common shares outstanding:			
Basic	60,662	54,420	53,221
Diluted	60,798	55,486	55,120

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

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended	December 31, 2019	December 31, 2018	December 31, 2017
		(in thousands)	
Net income	$ 213,322	$ 272,662	$ 191,276
Other comprehensive income (loss), net of tax:			
Benefit plan liability adjustments - net gain (loss) (net of tax of $1,886, $(660) and $1,030, respectively)	(6,253)	2,155	(1,890)
Benefit plan liability adjustments - prior service costs (net of tax of $2, $0 and $0, respectively)	(8)	—	—
Reclassification adjustment of benefit plan liability - net loss (net of tax of $434, $(586) and $(585), respectively)	1,179	1,901	1,072
Reclassification adjustment of benefit plan liability - prior service cost (net of tax of $19, $43 and $69, respectively)	(58)	(135)	(128)
Derivative instruments designated as cash flow hedges:			
Reclassification of net realized (gains) losses on settled/amortized interest rate swaps (net of tax of $(666), $(599) and $(1,029) , respectively)	2,185	2,252	1,912
Net unrealized gains (losses) on commodity derivatives (net of tax of $126, $(228) and $(135), respectively)	(422)	755	231
Reclassification of net realized (gains) losses on settled commodity derivatives (net of tax of $55, $(31) and $154, respectively)	(362)	99	(516)
Other comprehensive income (loss), net of tax	(3,739)	7,027	681
Comprehensive income	209,583	279,689	191,957
Less: comprehensive income attributable to non-controlling interest	(14,012)	(14,220)	(14,242)
Comprehensive income available for common stock	$ 195,571	$ 265,469	$ 177,715

See Note 16 for additional disclosures related to Comprehensive Income.

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

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS

	As of	
	December 31, 2019	December 31, 2018
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 9,777	$ 20,776
Restricted cash and equivalents	3,881	3,369
Accounts receivable, net	255,805	269,153
Materials, supplies and fuel	117,172	117,299
Derivative assets, current	342	1,500
Income tax receivable, net	16,446	12,978
Regulatory assets, current	43,282	48,776
Other current assets	26,479	29,982
Total current assets	473,184	503,833
Investments	21,929	41,013
Property, plant and equipment	6,784,679	6,000,015
Less accumulated depreciation and depletion	(1,281,493)	(1,145,136)
Total property, plant and equipment, net	5,503,186	4,854,879
Other assets:		
Goodwill	1,299,454	1,299,454
Intangible assets, net	13,266	14,337
Regulatory assets, non-current	228,062	235,459
Other assets, non-current	19,376	14,352
Total other assets, non-current	1,560,158	1,563,602
TOTAL ASSETS	$ 7,558,457	$ 6,963,327

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

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS
(Continued)

	As of	
	December 31, 2019	December 31, 2018
	(in thousands, except share amounts)	
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 193,523	$ 210,609
Accrued liabilities	226,767	215,501
Derivative liabilities, current	2,254	947
Regulatory liabilities, current	33,507	29,810
Notes payable	349,500	185,620
Current maturities of long-term debt	5,743	5,743
Total current liabilities	811,294	648,230
Long-term debt, net of current maturities	3,140,096	2,950,835
Deferred credits and other liabilities:		
Deferred income tax liabilities, net	360,719	311,331
Regulatory liabilities, non-current	503,145	510,984
Benefit plan liabilities	154,472	145,147
Other deferred credits and other liabilities	124,662	109,377
Total deferred credits and other liabilities	1,142,998	1,076,839
Commitments and contingencies (See Notes 6, 7, 8, 9, 14, 18, 19, and 20)		
Equity:		
Stockholders' equity -		
Common stock $1 par value; 100,000,000 shares authorized; issued: 61,480,658 and 60,048,567, respectively	61,481	60,049
Additional paid-in capital	1,552,788	1,450,569
Retained earnings	778,776	700,396
Treasury stock at cost - 3,956 and 44,253, respectively	(267)	(2,510)
Accumulated other comprehensive income (loss)	(30,655)	(26,916)
Total stockholders' equity	2,362,123	2,181,588
Noncontrolling interest	101,946	105,835
Total equity	2,464,069	2,287,423
TOTAL LIABILITIES AND TOTAL EQUITY	$ 7,558,457	$ 6,963,327

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

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended	December 31, 2019	December 31, 2018	December 31, 2017
	(in thousands)		
Operating activities:			
Net income	$ 213,322	$ 272,662	$ 191,276
Loss from discontinued operations, net of tax	—	6,887	17,099
Income from continuing operations	213,322	279,549	208,375
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	209,120	196,328	188,246
Deferred financing cost amortization	7,838	7,845	8,261
Impairment of investment	19,741	—	—
Stock compensation	12,095	12,390	7,626
Deferred income taxes	38,020	(24,239)	80,992
Employee benefit plans	12,406	14,068	10,141
Other adjustments, net	16,485	5,836	(4,773)
Change in certain operating assets and liabilities:			
Materials, supplies and fuel	2,052	(2,919)	(10,089)
Accounts receivable and other current assets	7,578	(45,966)	4,534
Accounts payable and other current liabilities	(34,906)	5,305	(28,222)
Regulatory assets - current	23,619	33,608	(15,407)
Regulatory liabilities - current	(15,158)	18,533	(4,536)
Contributions to defined benefit pension plans	(12,700)	(12,700)	(27,700)
Other operating activities, net	6,001	6,689	(8,418)
Net cash provided by operating activities of continuing operations	505,513	494,327	409,030
Net cash provided by (used in) operating activities of discontinued operations	—	(5,516)	19,231
Net cash provided by operating activities	505,513	488,811	428,261
Investing activities:			
Property, plant and equipment additions	(818,376)	(457,524)	(326,010)
Purchase of investment	—	(24,429)	—
Other investing activities	2,166	(4,281)	1,011
Net cash (used in) investing activities of continuing operations	(816,210)	(486,234)	(324,999)
Net cash provided by investing activities of discontinued operations	—	20,385	7,881
Net cash (used in) investing activities	(816,210)	(465,849)	(317,118)
Financing activities:			
Dividends paid on common stock	(124,647)	(106,591)	(96,744)
Common stock issued	101,358	300,834	4,408
Net (payments) borrowings of short-term debt	163,880	(25,680)	114,700
Long-term debt - issuance	1,100,000	700,000	—
Long-term debt - repayments	(905,743)	(854,743)	(105,743)
Distributions to noncontrolling interests	(17,901)	(19,617)	(18,397)
Other financing activities	(16,737)	(11,260)	(6,919)
Net cash provided by (used in) financing activities	300,210	(17,057)	(108,695)
Net change in cash, restricted cash and cash equivalents	(10,487)	5,905	2,448
Cash, restricted cash and cash equivalents beginning of year	24,145	18,240	15,792
Cash, restricted cash and cash equivalents end of year	$ 13,658	$ 24,145	$ 18,240

See Note 17 for supplemental disclosure of cash flow information.

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

FORM 10K

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY

(in thousands except share amounts)	Common Stock Shares	Common Stock Value	Treasury Stock Shares	Treasury Stock Value	Additional Paid in Capital	Retained Earnings	AOCI	Non controlling Interest	Total
Balance at December 31, 2016	53,397,467	$ 53,397	15,258	$ (791)	$1,138,982	$ 457,934	$(34,883)	$ 115,495	$ 1,730,134
Net income (loss) available for common stock	—	—	—	—	—	177,034	—	14,242	191,276
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	681	—	681
Reclassification of certain tax effects from AOCI	—	—	—	—	—	7,000	(7,000)	—	—
Dividends on common stock	—	—	—	—	—	(96,744)	—	—	(96,744)
Share-based compensation	134,266	134	23,806	(1,515)	8,948	—	—	—	7,567
Tax effect of share-based compensation	—	—	—	—	533	3,184	—	—	3,717
Issuance costs	—	—	—	—	(189)	—	—	—	(189)
Dividend reinvestment and stock purchase plan	48,253	49	—	—	3,107	—	—	—	3,156
Distributions to noncontrolling interest	—	—	—	—	(1,096)	209	—	(18,505)	(19,392)
Balance at December 31, 2017	53,579,986	$ 53,580	39,064	$ (2,306)	$1,150,285	$ 548,617	$(41,202)	$ 111,232	$ 1,820,206
Net income (loss) available for common stock	—	—	—	—	—	258,442	—	14,220	272,662
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	7,027	—	7,027
Reclassification of certain tax effects from AOCI	—	—	—	—	—	—	740	—	740
Reclassification to regulatory asset	—	—	—	—	—	—	6,519	—	6,519
Dividends on common stock	—	—	—	—	—	(106,591)	—	—	(106,591)
Share-based compensation	92,830	93	5,189	(204)	7,301	—	—	—	7,190
Issuance of common stock	6,371,690	6,372	—	—	292,628	—	—	—	299,000
Issuance costs	—	—	—	—	(15)	—	—	—	(15)
Dividend reinvestment and stock purchase plan	4,061	4	—	—	216	—	—	—	220
Other stock transactions	—	—	—	—	154	(72)	—	—	82
Redemption of and distributions to noncontrolling interest	—	—	—	—	—	—	—	(19,617)	(19,617)
Balance at December 31, 2018	60,048,567	$ 60,049	44,253	$ (2,510)	$1,450,569	$ 700,396	$(26,916)	$ 105,835	$ 2,287,423
Net income (loss) available for common stock	—	—	—	—	—	199,310	—	14,012	213,322
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	(3,739)	—	(3,739)
Dividends on common stock	—	—	—	—	—	(124,647)	—	—	(124,647)
Share-based compensation	103,759	104	(40,297)	2,243	4,729	—	—	—	7,076
Issuance of common stock	1,328,332	1,328	—	—	98,672	—	—	—	100,000
Issuance costs	—	—	—	—	(1,182)	—	—	—	(1,182)
Other	—	—	—	—	—	327	—	—	327
Implementation of ASU 2016-02 Leases	—	—	—	—	—	3,390	—	—	3,390
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(17,901)	(17,901)
Balance at December 31, 2019	61,480,658	$ 61,481	3,956	$ (267)	$1,552,788	$ 778,776	$(30,655)	$ 101,946	$ 2,464,069

Dividends per share paid were $2.05, $1.93 and $1.81 for the years ended December 31, 2019, 2018 and 2017, respectively.

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

(1) BUSINESS DESCRIPTION AND SIGNIFICANT ACCOUNTING POLICIES

Business Description

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

Segment Reporting

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

Our Electric Utilities segment includes the operating results of the regulated electric utility operations of Colorado Electric, South Dakota Electric, and Wyoming Electric, which supply regulated electric utility services to areas in Colorado, Montana, South Dakota and Wyoming. Our Gas Utilities segment consists of the operating results of our regulated natural gas utility subsidiaries in Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming.

Most of our non-utility business segments support our Electric Utilities. Our Power Generation segment, which is conducted through Black Hills Electric Generation and its subsidiaries, engages in independent power generation activities in Colorado, Iowa and Wyoming. Our Mining segment, which is conducted through WRDC, engages in mining activities located near Gillette, Wyoming. For further descriptions of our reportable business segments, see Note 5.

On November 1, 2017, our Board of Directors approved a complete divestiture of our Oil and Gas segment. We completed the divestiture of our Oil and Gas segment in 2018. The Oil and Gas segment assets and liabilities were classified as held for sale and the results of operations were shown in income (loss) from discontinued operations, other than certain general and administrative costs and interest expense which did not meet the criteria for income (loss) from discontinued operations in 2018 or 2017. At the time the assets were classified as held for sale, depreciation, depletion and amortization expenses were no longer recorded. Unless otherwise noted, the amounts presented in the accompanying notes to the consolidated financial statements relate to the Company's continuing operations. For more information on discontinued operations, see Note 21.

Use of Estimates and Basis of Presentation

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

Principles of Consolidation

The consolidated financial statements include the accounts of Black Hills Corporation and its wholly-owned and majority-owned and controlled subsidiaries. All intercompany balances and transactions have been eliminated in consolidation. For additional information on intercompany revenues, see Note 5.

Our Consolidated Statements of Income include operating activity of acquired companies beginning with their acquisition date. We use the proportionate consolidation method to account for our ownership interest in any jointly-owned electric utility generating facility, wind project or transmission tie. See Note 4 for additional information.

Variable Interest Entities

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

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

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

Cash and Cash Equivalents and Restricted Cash

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

Accounts Receivable and Allowance for Doubtful Accounts

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

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

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

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

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

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

2018	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 39,721	$ 35,125	$ (448)	$ 74,398
Gas Utilities	96,123	90,521	(2,592)	184,052
Power Generation	1,876	—	—	1,876
Mining	3,988	—	—	3,988
Corporate	5,008	—	(169)	4,839
Total	$ 146,716	$ 125,646	$ (3,209)	$ 269,153

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

	Balance at Beginning of Year	Additions Charged to Costs and Expenses	Recoveries and Other Additions	Write-offs and Other Deductions	Balance at End of Year
2019	$ 3,209	$ 5,795	$ 3,942	$ (10,502)	$ 2,444
2018	$ 3,081	$ 6,859	$ 4,092	$ (10,823)	$ 3,209
2017	$ 2,392	$ 4,926	$ 8,262	$ (12,499)	$ 3,081

Materials, Supplies and Fuel

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

	2019	2018
Materials and supplies	$ 82,809	$ 75,081
Fuel - Electric Utilities	2,425	2,850
Natural gas in storage	31,938	39,368
Total materials, supplies and fuel	$ 117,172	$ 117,299

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

Investments

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

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

The following table presents the carrying value of our investments (in thousands) as of December 31:

	2019	2018
Investment in privately held oil and gas company	$ 8,359	$ 28,100
Cash surrender value of life insurance contracts	13,056	12,812
Other investments	514	101
Total investments	$ 21,929	$ 41,013

Property, Plant and Equipment

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

The cost of regulated utility property, plant and equipment retired, or otherwise disposed of in the ordinary course of business, less salvage plus retirement costs, is charged to accumulated depreciation. Estimated removal costs associated with non-legal retirement obligations related to our regulated properties are reclassified from accumulated depreciation and reflected as regulatory liabilities. Retirement or disposal of all other assets result in gains or losses recognized as a component of operating income. Ordinary repairs and maintenance of property, except as allowed under rate regulations, are charged to operations as incurred.

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

Goodwill and Intangible Assets

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

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

The Company has determined that the reporting units for its goodwill impairment test are its operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which segment management regularly reviews the operating results. See Note 5 for additional business segment information.

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

We believe that the goodwill reflects the inherent value of the relatively stable, long-lived cash flows of the regulated electric and gas utility businesses, considering the regulatory environment, and the long-lived cash flow and rate base growth opportunities at our utilities. Goodwill amounts have not changed since 2016. As of December 31, 2019, 2018 and 2017, Goodwill balances were as follows (in thousands):

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

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

	2019	2018	2017
Intangible assets, net, beginning balance	$ 14,337	$ 7,559	$ 8,392
Additions [(a)]	—	7,602	—
Amortization expense [(b)]	(1,071)	(824)	(833)
Intangible assets, net, ending balance	$ 13,266	$ 14,337	$ 7,559

(a) The 2018 addition is related to the Busch Ranch 1 contract intangible asset. See Note 4 for further information.
(b) Amortization expense for existing intangible assets is expected to be $1.1 million for each year of the next five years.

Accrued Liabilities

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

	2019	2018
Accrued employee compensation, benefits and withholdings	$ 62,837	$ 63,742
Accrued property taxes	44,547	42,510
Customer deposits and prepayments	54,728	43,574
Accrued interest	31,868	31,759
CIAC current portion	1,952	1,485
Other (none of which is individually significant)	30,835	32,431
Total accrued liabilities	$ 226,767	$ 215,501

Asset Retirement Obligations

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

We initially record liabilities for the present value of retirement costs for which we have a legal obligation, with an equivalent amount added to the asset cost. The asset is then depreciated or depleted over the appropriate useful life and the liability is accreted over time by applying an interest method of allocation. Any difference in the actual cost of the settlement of the liability and the recorded amount is recognized as a gain or loss in the results of operations at the time of settlement for our non-regulated operations. Additional information is included in Note 8.

Fair Value Measurements

Financial Instruments

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

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

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

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

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

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

Valuation Methodologies for Derivatives

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

Additional information on fair value measurements is included in Notes 10, 11 and 18.

Derivatives and Hedging Activities

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

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

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

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

Deferred Financing Costs

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

Regulatory Accounting

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

- Certain costs, which would otherwise be charged to expense or OCI, are deferred as regulatory assets based on the expected ability to recover the costs in future rates.

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

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

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

As of December 31, 2019 and 2018, we had total regulatory assets of $271 million and $284 million respectively, and total regulatory liabilities of $537 million and $541 million respectively. See Note 13 for further information.

Income Taxes

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

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

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

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

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

Earnings per Share of Common Stock

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

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

	2019	2018	2017
Net income available for common stock	$ 199,310	$ 258,442	$ 177,034
Weighted average shares - basic	60,662	54,420	53,221
Dilutive effect of:			
Equity Units	—	898	1,783
Equity compensation	136	168	116
Weighted average shares - diluted	60,798	55,486	55,120
Net income available for common stock, per share - Diluted	$ 3.28	$ 4.66	$ 3.21

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

	2019	2018	2017
Equity compensation	1	16	11
Anti-dilutive shares excluded from computation of earnings per share	1	16	11

Noncontrolling Interests

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

Share-Based Compensation

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

Recently Issued Accounting Standards

Simplifying the Accounting for Income Taxes, ASU 2019-12

In December 2019, the FASB issued ASU 2019-12, *Simplifying the Accounting for Income Taxes* as part of its overall simplification initiative to reduce costs and complexity in applying accounting standards while maintaining or improving the usefulness of the information provided to users of the financial statements. Amendments include removal of certain exceptions to the general principles of ASC 740*, Income Taxes*, and simplification in several other areas such as accounting for a franchise tax (or similar tax) that is partially based on income. The new guidance is effective for interim and annual periods beginning after December 15, 2020 with early adoption permitted. We are currently reviewing this standard to assess the impact on our financial position, results of operations and cash flows.

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

In August 2018, the FASB issued ASU 2018-15, *Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract*, which aligns the requirements for recording implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. As a result, certain categories of implementation costs that previously would have been charged to expense as incurred are now capitalized as prepayments and amortized over the term of the arrangement. The new guidance is effective for annual periods beginning after December 15, 2019, and interim periods within those fiscal years. The new guidance can be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. Early adoption is permitted. We adopted this standard prospectively on January 1, 2020. Adoption of this guidance did not have a material impact on our financial position, results of operations or cash flows.

Simplifying the Test for Goodwill Impairment, ASU 2017-04

In January 2017, the FASB issued ASU 2017-04, *Simplifying the Test for Goodwill Impairment* by eliminating step 2 from the goodwill impairment test. Under the new guidance, if the carrying amount of a reporting unit exceeds its fair value, an impairment loss will be recognized in an amount equal to that excess, limited to the amount of goodwill allocated to that reporting unit. The new standard is effective for interim and annual reporting periods beginning after December 15, 2019, applied on a prospective basis with early adoption permitted. We adopted this standard prospectively on January 1, 2020. Adoption of this guidance is not expected to have any impact on our financial position, results of operations or cash flows.

Financial Instruments -- Credit Losses: Measurement of Credit Losses on Financial Instruments, ASU 2018-19

In June 2016, the FASB issued ASU 2016-13, *Financial Instruments -- Credit Losses: Measurement of Credit Losses on Financial Instruments,* which was subsequently amended by ASU 2018-19, ASU 2019-04, 2019-05, 2019-10, and 2019-11. The standard introduces new accounting guidance for credit losses on financial instruments within its scope, including trade receivables. This new guidance adds an impairment model that is based on expected losses rather than incurred losses. It is effective for interim and annual reporting periods beginning after December 15, 2019, with early adoption permitted.

We adopted this standard on January 1, 2020 with prior year comparative financial information remaining as previously reported when transitioning to the new standard. On January 1, 2020, we recorded an increase to our allowance for doubtful accounts, primarily associated with the inclusion of expected losses on unbilled revenue. Adoption of this standard did not have a material impact on our financial position, results of operations or cash flows.

Recently Adopted Accounting Standards

Leases, ASU 2016-02

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)* to increase transparency and comparability among organizations by requiring the recognition of right-of-use assets and lease liabilities on the balance sheet for most leases, whereas previously only financing-type lease liabilities (capital leases) were recognized on the balance sheet. Under the new standard, disclosures are required to meet the objective of enabling users of financial statements to assess the amount, timing and uncertainty of cash flows arising from leases.

We adopted the standard effective January 1, 2019. We elected not to recast comparative periods coinciding with the new lease standard transition and will report these comparative periods as presented under previous lease guidance. In addition, we elected the package of practical expedients permitted under the transition guidance with the new standard, which among other things, allowed us to carry forward the historical lease classification. We also elected the practical expedient related to land easements, allowing us to carry forward our accounting treatment for existing land easement agreements.

Adoption of the new standard resulted in the recording of an operating lease right-of-use asset of $3.1 million, an operating lease obligation liability of $3.2 million, and an accrued receivable of $4.5 million, as of January 1, 2019. The cumulative effect of the adoption, net of tax impact, was $3.4 million, which was recorded as an adjustment to retained earnings at January 1, 2019.

See Note 14 for additional details on leases.

Derivatives and Hedging: Targeted Improvements to Accounting for Hedging Activities, ASU 2017-12

In August 2017, the FASB issued ASU 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvement to Accounting for Hedging Activities.* This standard better aligns risk management activities and financial reporting for hedging relationships, simplifies hedge accounting requirements and improves disclosures of hedging arrangements. We have adopted this standard on January 1, 2019. Adoption of this standard did not have a material impact on our financial position, results of operations or cash flows.

(2) REVENUE

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

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

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

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

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

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

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

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

(a) Due to the changes in our segment disclosures discussed in Note 5, Power Generation Wholesale revenue was revised for the year ended December 31, 2018, which resulted in an increase of $38 million. The changes to Power Generation Wholesale revenue were offset by a decrease to Power Generation Other revenues of $35 million and a decrease to eliminations in Inter-company Revenues of $3.5 million. There was no impact to our consolidated Total Revenues.

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

Revenue Not in Scope of ASC 606

Other revenues included in the table above include our revenue accounted for under separate accounting guidance, including lease revenue under ASC 842, derivative revenue under ASC 815 and alternative revenue programs revenue under ASC 980. Effective January 1, 2019, we changed how we account for the PPA between Black Hills Colorado IPP and Colorado Electric at the segment level and now recognize on an accrual basis, rather than a finance lease. See Note 5 for additional information.

Significant Judgments and Estimates

Unbilled Revenue

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

Contract Balances

The nature of our primary revenue contracts provides an unconditional right to consideration upon service delivery; therefore, no customer contract assets or liabilities exist. The unconditional right to consideration is represented by the balance in our Accounts Receivable further discussed in Note 1. We do not typically incur costs that would be capitalized to obtain or fulfill a contract.

(3) PROPERTY, PLANT AND EQUIPMENT

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

	2019		2018		Lives (in years)	
Electric Utilities	Property, Plant and Equipment	Weighted Average Useful Life (in years)	Property, Plant and Equipment [(b)]	Weighted Average Useful Life (in years)	Minimum	Maximum
Electric plant:						
Production	$ 1,348,049	41	$ 1,318,643	41	32	46
Electric transmission	483,640	51	437,082	51	43	54
Electric distribution	861,042	47	793,725	48	46	50
Plant acquisition adjustment [(a)]	4,870	32	4,870	32	32	32
General	259,266	28	233,531	28	26	33
Total electric plant in service	2,956,867		2,787,851			
Construction work in progress	102,268		60,480			
Total electric plant	3,059,135		2,848,331			
Less accumulated depreciation and amortization	(670,861)		(615,365)			
Electric plant net of accumulated depreciation and amortization	$ 2,388,274		$ 2,232,966			

(a) The plant acquisition adjustment is included in rate base and is being recovered with 11 years remaining.

(b) Due to the changes in our segment disclosures discussed in Note 5, Total electric plant in service, Accumulated depreciation and amortization, and Electric plant net of accumulated depreciation and amortization were revised as of December 31, 2018 which resulted in an increase (decrease) of ($261) million, $91 million and ($170) million, respectively. There was no impact on our consolidated Plant, property and equipment.

Gas Utilities	2019 Property, Plant and Equipment	2019 Weighted Average Useful Life (in years)	2018 Property, Plant and Equipment	2018 Weighted Average Useful Life (in years)	Lives (in years) Minimum	Lives (in years) Maximum
Gas plant:						
Production	$ 13,000	35	$ 13,580	35	24	71
Gas transmission	516,172	50	423,873	48	22	67
Gas distribution	1,857,233	43	1,595,644	42	30	56
Cushion gas - depreciable [(a)]	3,539	28	3,539	28	28	28
Cushion gas - not depreciable [(a)]	44,443	N/A	46,369	N/A	N/A	N/A
Storage	46,977	31	29,335	30	27	49
General	437,054	20	355,920	19	10	24
Total gas plant in service	2,918,418		2,468,260			
Construction work in progress	63,080		38,271			
Total gas plant	2,981,498		2,506,531			
Less accumulated depreciation and amortization	(336,721)		(279,580)			
Gas plant net of accumulated depreciation and amortization	$ 2,644,777		$ 2,226,951			

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

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

2018	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Net Property, Plant and Equipment	Weighted Average Useful Life	Lives (in years) Minimum	Lives (in years) Maximum
Power Generation [(a)]	$ 435,438	$ 11,796	$ 447,234	$ (137,832)	$ 309,402	31	2	40
Mining	$ 175,650	$ —	$ 175,650	$ (111,689)	$ 63,961	13	2	59

(a) Due to the changes in our segment disclosures discussed in Note 5, Property, plant and equipment, Accumulated depreciation and amortization, and Net property, plant and equipment were revised as of December 31, 2018 which resulted in an increase (decrease) of $261 million, ($73) million and $188 million, respectively. There was no impact on our consolidated Plant, property and equipment.

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

2018							Lives (in years)	
	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation and Amortization	Net Property, Plant and Equipment	Weighted Average Useful Life	Minimum	Maximum
Corporate [a]	$ 5,721	$ 16,548	$ 22,269	$ (670)	$ 21,599	8	3	30

(a) Due to the changes in our segment disclosures discussed in Note 5, Corporate Accumulated depreciation and amortization and Net property, plant and equipment were revised as of December 31, 2018 which resulted in an increase (decrease) of ($18) million and ($18) million respectively. There was no impact on our consolidated Plant, property and equipment.

(4) JOINTLY OWNED FACILITIES

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

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

- South Dakota Electric also owns a 35% interest in, and is the operator of, the Converter Station Site and South Rapid City Interconnection (the transmission tie), an AC-DC-AC transmission tie. Basin Electric owns the remaining ownership percentage. The transmission tie provides an interconnection between the Western and Eastern transmission grids, which provides us with access to both the WECC and SPP regions. The total transfer capacity of the tie is 400 MW, including 200 MW from West to East and 200 MW from East to West. South Dakota Electric is committed to pay its proportionate share of the additions and replacements and operating and maintenance expenses of the transmission tie.

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

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

At December 31, 2019, our interests in jointly-owned generating facilities and transmission systems were (in thousands):

	Plant in Service	Construction Work in Progress	Less Accumulated Depreciation	Plant Net of Accumulated Depreciation
Wyodak Plant	$ 116,074	$ 729	$ (64,413)	$ 52,390
Transmission Tie	$ 19,862	$ 4,161	$ (6,612)	$ 17,411
Wygen I	$ 120,824	$ 289	$ (48,703)	$ 72,410
Wygen III	$ 146,161	$ 400	$ (25,518)	$ 121,043

Jointly Owned Facility - Related Party

Colorado Electric owns 50% of Busch Ranch I while Black Hills Electric Generation owns the remaining 50% ownership interest. Each company is obligated to make payments for costs associated with their proportionate share of the costs of operating the wind farm over the life of the facility. On December 11, 2018, Black Hills Electric Generation purchased its 50% ownership interest in Busch Ranch I for $16 million. Colorado Electric retains responsibility for operations of the wind farm. We recorded this purchase as an asset acquisition at fair value with $8.7 million of the purchase price recorded as wind generation assets, and $7.6 million recorded as an intangible asset, reflective of the fair value of the PPA. Black Hills Electric Generation provides its share of energy from the wind farm to Colorado Electric through a PPA, which expires in October 2037.

(5) BUSINESS SEGMENT INFORMATION

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

Accounting standards for presentation of segments require an approach based on the way we organize the segments for making operating decisions and how the chief operating decision maker (CODM) assesses performance. Effective January 1, 2019, we concluded that adjusted operating income, instead of net income available for common stock which was used previously, is the most relevant metric for measuring segment performance. The change to our segment performance measure resulted in a revision of the Company's segment disclosures for all periods to report adjusted operating income as the measure of segment performance.

Prior to January 1, 2019, operating income for the Electric Utilities and Power Generation segments and Corporate and Other included the impacts of finance lease accounting relating to Colorado Electric's PPA with Black Hills Colorado IPP. This PPA provides 200 MW of energy and capacity to Colorado Electric from Black Hills Colorado IPP's combined-cycle turbines and expires on December 31, 2031. Finance lease accounting required us to de-recognize the asset from Black Hills Colorado IPP (Power Generation segment), which legally owns the asset, and recognize it at Colorado Electric (Electric Utilities segment).

The CODM assesses the performance of our segments using adjusted operating income, which recognizes intersegment revenues, costs, and assets for Colorado Electric's PPA with Black Hills Colorado IPP on an accrual basis rather than as a finance lease. Effective January 1, 2019, we changed how we account for this PPA at the segment level, which impacts disclosures for all periods for revenues, fuel and purchased power cost, operating income and total assets for the Electric Utilities and Power Generation segments as well as Corporate and Other. There were no revisions to Gas Utilities and Mining segments and this change had no effect on our consolidated revenues, fuel and purchased power cost, operating income or total assets.

Segment information was as follows (in thousands):

Total Assets (net of intercompany eliminations) as of December 31,	2019	2018
Electric Utilities [(a)]	$ 2,900,983	$ 2,707,695
Gas Utilities	4,032,339	3,623,475
Power Generation [(a)]	417,715	342,085
Mining	77,175	80,594
Corporate and Other	130,245	209,478
Total assets	$ 7,558,457	$ 6,963,327

(a) Due to the changes in our segment disclosures, Electric Utilities and Power Generation Total assets were revised as of December 31, 2018 which resulted in an increase (decrease) of ($188) million and $188 million, respectively. There was no impact on our consolidated Total assets.

Capital Expenditures [(a)] for the years ended December 31,	2019	2018
Capital expenditures		
Electric Utilities	$ 222,911	$ 152,524
Gas Utilities	512,366	288,438
Power Generation	85,346	30,945
Mining	8,430	18,794
Corporate and Other	20,702	11,723
Total capital expenditures of continuing operations	849,755	502,424
Total capital expenditures of discontinued operations	—	2,402
Total capital expenditures	$ 849,755	$ 504,826

(a) Includes accruals for property, plant and equipment as disclosed in Note 17.

Property, Plant and Equipment as of December 31,	2019	2018
Electric Utilities [(a)]	$ 3,059,135	$ 2,848,331
Gas Utilities	2,981,498	2,506,531
Power Generation [(a)]	534,518	447,234
Mining	180,473	175,650
Corporate and Other	29,055	22,269
Total property, plant and equipment	$ 6,784,679	$ 6,000,015

(a) Due to the changes in our segment disclosures, Electric Utilities and Power Generation Property, Plant and Equipment were revised as of December 31, 2018 which resulted in an increase (decrease) of ($261) million and $261 million, respectively. There was no impact on our consolidated Property, Plant and Equipment.

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

(a) In 2019 we recorded an impairment of our investment in equity securities of a privately held oil and gas company. See Note 1 for additional information.

Consolidating Income Statement

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

(a) Income tax benefit (expense) includes a tax benefit of $73 million resulting from legal entity restructuring. See Note 15.

(b) Due to changes in our segment disclosures, Adjusted operating income and related income statement accounts were revised for the year ended December 31, 2018, which resulted in an increase (decrease) as follows (in millions):

Year ended December 31, 2018	Electric Utilities	Power Generation	Inter-Company Eliminations	Total
Inter-company operating revenue - Contracts with customers	$ —	$ 3.5	$ (3.5)	$ —
Fuel, purchased power and cost of natural gas sold	6.7	—	(6.7)	—
Depreciation, depletion and amortization	(13.1)	9.2	3.9	—
Adjusted operating income (loss)	$ 6.4	$ (5.7)	$ (0.7)	$ —

Year ended December 31, 2017	Consolidating Income Statement						
	Electric Utilities [b]	Gas Utilities	Power Generation [b]	Mining	Corporate	Inter-Company Eliminations [b]	Total
Revenue	$ 689,945	$ 947,595	$ 7,263	$ 35,463	$ —	$ —	$1,680,266
Inter-company revenue	14,705	35	87,357	31,158	344,685	(477,940)	—
Total revenue	704,650	947,630	94,620	66,621	344,685	(477,940)	1,680,266
Fuel, purchased power and cost of natural gas sold	274,363	409,603	9,340	—	151	(130,169)	563,288
Operations and maintenance	172,307	269,190	23,042	44,882	296,067	(293,492)	511,996
Depreciation, depletion and amortization	80,243	83,732	15,548	8,239	21,031	(20,547)	188,246
Adjusted operating income (loss)	177,737	185,105	46,690	13,500	27,436	(33,732)	416,736
Interest expense, net							(137,102)
Other income (expense), net							2,108
Income tax benefit (expense)							(73,367)
Income from continuing operations							208,375
(Loss) from discontinued operations, net of tax[a]							(17,099)
Net income							191,276
Net income attributable to noncontrolling interest							(14,242)
Net income available for common stock							$ 177,034

(a) Discontinued operations includes oil and gas property impairments. See Note 21.
(b) Due to changes in our segment disclosures, Adjusted operating income and related income statement accounts were revised for the year ended December 31, 2017, which resulted in an increase (decrease) as follows (in millions):

Year ended December 31, 2017	Electric Utilities	Power Generation	Inter-Company Eliminations	Total
Inter-company revenue	$ —	$ 3.1	$ (3.1)	$ —
Fuel, purchased power and cost of natural gas sold	6.0	—	(6.0)	—
Depreciation, depletion and amortization	(13.1)	9.6	3.5	—
Adjusted operating income (loss)	$ 7.1	$ (6.5)	$ (0.6)	$ —

(6) LONG-TERM DEBT

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

	Due Date	Interest Rate at December 31, 2019	Balance Outstanding December 31, 2019	Balance Outstanding December 31, 2018
Corporate				
Senior unsecured notes due 2023	November 30, 2023	4.25%	$ 525,000	$ 525,000
Senior unsecured notes due 2020	July 15, 2020	N/A	—	200,000
Senior unsecured notes due 2026	January 15, 2026	3.95%	300,000	300,000
Senior unsecured notes due 2027	January 15, 2027	3.15%	400,000	400,000
Senior unsecured notes due 2033	May 1, 2033	4.35%	400,000	400,000
Senior unsecured notes, due 2046	September 15, 2046	4.20%	300,000	300,000
Senior unsecured notes, due 2029	October 15, 2029	3.05%	400,000	—
Senior unsecured notes, due 2049	October 15, 2049	3.88%	300,000	—
Corporate term loan due 2021 [(a)]	June 17, 2021	N/A	—	300,000
Corporate term loan due 2021	June 7, 2021	2.32%	7,178	12,921
Total Corporate debt			2,632,178	2,437,921
Less unamortized debt discount			(6,462)	(5,122)
Total Corporate debt, net			2,625,716	2,432,799
South Dakota Electric				
Series 94A Debt, variable rate [(b)]	June 1, 2024	1.84%	2,855	2,855
First Mortgage Bonds due 2032	August 15, 2032	7.23%	75,000	75,000
First Mortgage Bonds due 2039	November 1, 2039	6.13%	180,000	180,000
First Mortgage Bonds due 2044	October 20, 2044	4.43%	85,000	85,000
Total South Dakota Electric debt			342,855	342,855
Less unamortized debt discount			(82)	(86)
Total South Dakota Electric debt, net			342,773	342,769
Wyoming Electric				
Industrial development revenue bonds due 2021[(a)]	September 1, 2021	1.68%	7,000	7,000
Industrial development revenue bonds due 2027[(a)]	March 1, 2027	1.68%	10,000	10,000
First Mortgage Bonds due 2037	November 20, 2037	6.67%	110,000	110,000
First Mortgage Bonds due 2044	October 20, 2044	4.53%	75,000	75,000
Total Wyoming Electric debt			202,000	202,000
Less unamortized debt discount			—	—
Total Wyoming Electric debt, net			202,000	202,000
Total long-term debt			3,170,489	2,977,568
Less current maturities			5,743	5,743
Less unamortized deferred financing costs [(b)]			24,650	20,990
Long-term debt, net of current maturities and deferred financing costs			$ 3,140,096	$ 2,950,835

(a) Variable interest rate.

(b) Includes deferred financing costs associated with our Revolving Credit Facility of $1.7 million and $2.3 million as of December 31, 2019 and December 31, 2018, respectively.

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

2020	$	5,743
2021	$	8,435
2022	$	—
2023	$	525,000
2024	$	2,855
Thereafter	$	2,635,000

Our debt securities contain certain restrictive financial covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2019.

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

Debt Transactions

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

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

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

On December 12, 2018, we paid off the $250 million, 2.5% senior unsecured notes due January 11, 2019. Proceeds from the November 1, 2018 Equity Unit conversion were used to pay off this debt.

On August 17, 2018, we issued $400 million principal amount, 4.350% senior unsecured notes due May 1, 2033. A portion of these notes were issued in a private exchange that resulted in the retirement of all $299 million principal amount of our RSNs due 2028. The remainder of the notes were sold for cash in a public offering, with the net proceeds being used to pay down short-term debt.

The issuance of the $400 million senior notes was the culmination of a series of transactions that also included the contractually required remarketing of such RSNs on behalf of the holders of our Equity Units, with the proceeds being deposited as collateral to secure the obligations of those holders under the purchase contracts included in the Equity Units (see Note 12). As a result of the remarketing, the annual interest rate on such RSNs was automatically reset to 4.579% (however, because the RSNs were then immediately retired, no interest accrued at this reset rate).

On July 30, 2018, we amended and restated our unsecured term loan due August 2019. This amended and restated term loan, with $300 million outstanding at December 31, 2018, had a maturity date of July 30, 2020 and had substantially similar terms and covenants as the amended and restated Revolving Credit Facility. This term loan was later amended on June 17, 2019 and then repaid using proceeds from the October 3, 2019 public debt offering.

Amortization Expense

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

Deferred Financing Costs Remaining at December 31, 2019	Amortization Expense for the years ended December 31, 2019	2018	2017
$ 24,650	$ 3,242	$ 2,829	$ 3,349

Dividend Restrictions

Our credit facility and other debt obligations contain restrictions on the payment of cash dividends when a default or event of default occurs. As of December 31, 2019, we were in compliance with these covenants.

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our shareholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries. The following restrictions on distributions from our subsidiaries existed at December 31, 2019:

- Our utilities are generally limited to the amount of dividends allowed to be paid to our utility holding company under the Federal Power Act and settlement agreements with state regulatory jurisdictions. As of December 31, 2019, the restricted net assets at our Electric and Gas Utilities were approximately $156 million.

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

(7) NOTES PAYABLE

We had the following short-term debt outstanding at the Consolidated Balance Sheets date (in thousands):

	December 31, 2019		December 31, 2018	
	Balance Outstanding	Letters of Credit [(a)]	Balance Outstanding	Letters of Credit [(a)]
Revolving Credit Facility	$ —	$ 30,274	$ —	$ 22,311
CP Program	349,500	—	185,620	—
Total	$ 349,500	$ 30,274	$ 185,620	$ 22,311

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

Revolving Credit Facility and CP Program

On July 30, 2018, we amended and restated our corporate Revolving Credit Facility, maintaining total commitments of $750 million and extending the term through July 30, 2023 with two one year extension options (subject to consent from lenders). This facility is similar to the former revolving credit facility, which includes an accordion feature that allows us, with the consent of the administrative agent, the issuing agents and each bank increasing or providing a new commitment, to increase total commitments up to $1.0 billion. Borrowings continue to be available under a base rate or various Eurodollar rate options. The interest costs associated with the letters of credit or borrowings and the commitment fee under the Revolving Credit Facility are determined based upon our Corporate credit rating from S&P, Fitch, and Moody's for our senior unsecured long-term debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings, and letters of credit were 0.125%, 1.125%, and 1.125%, respectively, at December 31, 2019. Based on our credit ratings, a 0.175% commitment fee was charged on the unused amount at December 31, 2019.

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

Our net short-term borrowings (payments) during 2019 were $164 million. As of December 31, 2019, the weighted average interest rate on short-term borrowings was 2.03%.

Total accumulated deferred financing costs on the Revolving Credit Facility of $6.7 million are being amortized over its estimated useful life and were included in Interest expense on the accompanying Consolidated Statements of Income. See Note 6 above for additional details.

Debt Covenants

Under our Revolving Credit Facility and term loan agreements we are required to maintain a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.65 to 1.00. Our Consolidated Indebtedness to Capitalization Ratio is calculated by dividing (i) Consolidated Indebtedness, which includes letters of credit and certain guarantees issued by (ii) Capital, which includes Consolidated Indebtedness plus Net Worth, which excludes noncontrolling interest in subsidiaries. Subject to applicable cure periods, a violation of any of these covenants would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding. As of December 31, 2019, we were in compliance with these covenants.

(8) ASSET RETIREMENT OBLIGATIONS

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

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

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

	December 31, 2017	Liabilities Incurred	Liabilities Settled	Accretion	Revisions to Prior Estimates [b]	December 31, 2018
Electric Utilities	$ 6,287	$ —	$ —	$ 269	$ 2	$ 6,558
Gas Utilities	33,238	152	—	1,237	—	34,627
Mining	12,499	—	(4)	649	2,471	15,615
Total	$ 52,024	$ 152	$ (4)	$ 2,155	$ 2,473	$ 56,800

(a) The increase in Electric Utilities Revisions to Prior Estimates was primarily driven by an increase to the estimated cost to decommission certain regulated wind farm assets.
(b) The changes in the Mining Revision to Prior Estimates were primarily driven by changes in estimated costs associated with back-filling the pit with overburden removed during the mining process.
(c) We reclassified $0.3 million of ARO as of December 31, 2018 related to Busch Ranch I from Electric Utilities to the Power Generation segment as a result of Black Hills Electric Generation's purchase of its 50% ownership interest in Busch Ranch I. Additional liabilities were incurred in 2019 from new wind assets.

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

(9) RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operations of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures. Valuation methodologies for our derivatives are detailed within Note 1.

Market Risk

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

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

- Interest rate risk associated with our variable debt as described in Notes 6 and 7.

Credit Risk

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

For production and generation activities, 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, prepayments, 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 and any specific customer collection issue that is identified.

Our credit exposure at December 31, 2019 was concentrated primarily among retail utility customers, investment grade companies, cooperative utilities and federal agencies. Our derivative and hedging activities included in the accompanying Consolidated Balance Sheets, Consolidated Statements of Income and Consolidated Statements of Comprehensive Income (Loss) are detailed below and within Note 10.

Utilities

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 volatility in natural gas prices. Therefore, as allowed or required by state utility commissions, we have entered into commission-approved hedging programs utilizing natural gas futures, options, over-the-counter swaps and basis swaps to reduce our customers' underlying exposure to these fluctuations. These transactions are considered derivatives, and in accordance with accounting standards for derivatives and hedging, mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets, net of balance sheet offsetting as permitted by GAAP.

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

We buy, sell and deliver natural gas at competitive prices by managing commodity price risk. As a result of these activities, this area of our business is exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks using over-the-counter and exchange traded options and swaps with counterparties in anticipation of forecasted purchases and/or sales during time frames ranging from January 2020 through December 2021. A portion of our over-the-counter swaps have been designated as cash flow hedges to mitigate the commodity price risk associated with deliveries under fixed price forward contracts to deliver gas to our Choice Gas Program customers. The effective portion of the gain or loss on these designated derivatives is reported in AOCI in the accompanying Consolidated Balance Sheets and the ineffective portion, if any, is reported in Fuel, purchased power and cost of natural gas sold. Effectiveness of our hedging position is evaluated at least quarterly.

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

	December 31, 2019		December 31, 2018	
	Notional (MMBtus)	Maximum Term (months) [a]	Notional (MMBtus)	Maximum Term (months) [a]
Natural gas futures purchased	1,450,000	12	4,000,000	24
Natural gas options purchased, net	3,240,000	3	4,320,000	13
Natural gas basis swaps purchased	1,290,000	12	3,960,000	24
Natural gas over-the-counter swaps, net [b]	4,600,000	24	3,660,000	24
Natural gas physical commitments, net [c]	13,548,235	12	18,325,852	30

(a) Term reflects the maximum forward period hedged.
(b) As of December 31, 2019, 1,415,000 MMBtus of natural gas over-the-counter swaps purchased were designated as cash flow hedges.
(c) Volumes exclude contracts that qualify for normal purchase, normal sales exception.

Based on December 31, 2019 prices, a $0.5 million gain would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. As market prices fluctuate, estimated and actual realized gains or losses will change during future periods.

Cash Flow Hedges

The impact of cash flow hedges on our Consolidated Statements of Income is presented below for the years ended December 31, 2019, 2018 and 2017 (in thousands). Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

	December 31, 2019	
Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income
Interest rate swaps	Interest expense	$ (2,851)
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	417
Total impact from cash flow hedges		$ (2,434)

	December 31, 2018	
Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income
Interest rate swaps	Interest expense	$ (2,851)
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(130)
Total impact from cash flow hedges		$ (2,981)

	December 31, 2017	
Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income
Interest rate swaps	Interest expense	$ (2,941)
Commodity derivatives	Net (loss) from discontinued operations	913
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(243)
Total impact from cash flow hedges		$ (2,271)

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss) for the years ended December 31, 2019, 2018 and 2017 (in thousands).

	December 31, 2019	December 31, 2018	December 31, 2017
Increase (decrease) in fair value:			
Forward commodity contracts	$ (548)	$ 983	$ 366
Recognition of (gains) losses in earnings due to settlements:			
Interest rate swaps	2,851	2,851	2,941
Forward commodity contracts	(417)	130	(670)
Total other comprehensive income (loss) from hedging	$ 1,886	$ 3,964	$ 2,637

Derivatives Not Designated as Hedge Instruments

The following table summarizes the impacts of derivative instruments not designated as hedge instruments on our Consolidated Statements of Income for the years ended December 31, 2019, 2018 and 2017 (in thousands). Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

		December 31, 2019	December 31, 2018	December 31, 2017
Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	$ (1,100)	$ 1,101	$ (2,207)
		$ (1,100)	$ 1,101	$ (2,207)

As discussed above, financial instruments used in our regulated utilities are not designated as cash flow hedges. However, there is no earnings impact because the unrealized gains and losses arising from the use of these financial instruments are recorded as Regulatory assets or Regulatory liabilities. The net unrealized losses included in our Regulatory assets or Regulatory liability accounts related to the hedges in our Utilities were $3.3 million and $6.2 million at December 31, 2019 and 2018, respectively.

(10) FAIR VALUE MEASUREMENTS

Nonrecurring Fair Value Measurement

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

Recurring Fair Value Measurements

Amounts included in cash collateral and counterparty netting in the following tables represent the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions, netting of asset and liability positions permitted in accordance with accounting standards for offsetting as well as cash collateral posted with the same counterparties.

A discussion of fair value of financial instruments is included in Note 11. The following tables set forth, by level within the fair value hierarchy, our gross assets and gross liabilities and related offsetting as permitted by GAAP that were accounted for at fair value on a recurring basis for derivative instruments (in thousands):

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

	As of December 31, 2018				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
Assets:					
Commodity derivatives - Utilities	$ —	2,927	$ —	$ (1,408)	$ 1,519
Total	$ —	$ 2,927	$ —	$ (1,408)	$ 1,519
Liabilities:					
Commodity derivatives - Utilities	$ —	$ 6,801	$ —	$ (5,794)	$ 1,007
Total	$ —	$ 6,801	$ —	$ (5,794)	$ 1,007

Fair Value Measures by Balance Sheet Classification

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

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

	Balance Sheet Location	December 31, 2019	December 31, 2018
Derivatives designated as hedges:			
Asset derivative instruments:			
Current commodity derivatives	Derivative assets - current	$ 1	$ 415
Noncurrent commodity derivatives	Other assets, non-current	3	18
Liability derivative instruments:			
Current commodity derivatives	Derivative liabilities - current	(490)	(114)
Noncurrent commodity derivatives	Other deferred credits and other liabilities	(29)	(4)
Total derivatives designated as hedges		$ (515)	$ 315
Not designated as hedges:			
Asset derivative instruments:			
Current commodity derivatives	Derivative assets - current	$ 341	$ 1,085
Noncurrent commodity derivatives	Other assets, non-current	2	1
Liability derivative instruments:			
Current commodity derivatives	Derivative liabilities - current	(1,764)	(833)
Noncurrent commodity derivatives	Other deferred credits and other liabilities	(63)	(56)
Total derivatives not designated as hedges		$ (1,484)	$ 197

Derivatives Offsetting

It is our policy to offset, in our Consolidated Balance Sheets, contracts which provide for legally enforceable netting of our accounts receivable and payable and derivative activities.

As required by accounting standards for derivatives and hedges, fair values within the following tables reconcile the gross amounts to the net amounts. Amounts included in Gross Amounts Offset on Consolidated Balance Sheets in the following tables include the netting of asset and liability positions permitted in accordance with accounting standards for offsetting as well as the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions as well as cash collateral posted with the same counterparties. Additionally, the amounts reflect cash collateral on deposit in margin accounts at December 31, 2019 and 2018, to collateralize certain financial instruments, which are included in Derivative assets and/or Derivative liabilities. Therefore, the gross amounts are not indicative of either our actual credit exposure or net economic exposure.

Offsetting of derivative assets and derivative liabilities on our Consolidated Balance Sheets at December 31, 2019 was as follows (in thousands):

Derivative Assets	Gross Amounts of Derivative Assets	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Assets on Consolidated Balance Sheets
Commodity derivative assets subject to a master netting agreement or similar arrangement	$ 1,085	$ (1,085)	$ —
Commodity derivative assets not subject to a master netting agreement or similar arrangement	348	—	348
Total derivative assets	$ 1,433	$ (1,085)	$ 348

Derivative Liabilities	Gross Amounts of Derivative Liabilities	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Liabilities on Consolidated Balance Sheets
Commodity derivative liabilities subject to a master netting agreement or similar arrangement	$ 2,908	$ (2,908)	$ —
Commodity derivative liabilities not subject to a master netting agreement or similar arrangement	2,345	—	2,345
Total derivative liabilities	$ 5,253	$ (2,908)	$ 2,345

Offsetting of derivative assets and derivative liabilities on our Consolidated Balance Sheets as of December 31, 2018 were as follows (in thousands):

Derivative Assets	Gross Amounts of Derivative Assets	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Assets on Consolidated Balance Sheets
Commodity derivative assets subject to a master netting agreement or similar arrangement	$ 1,408	$ (1,408)	$ —
Commodity derivative assets not subject to a master netting agreement or similar arrangement	1,519	—	1,519
Total derivative assets	$ 2,927	$ (1,408)	$ 1,519

Derivative Liabilities	Gross Amounts of Derivative Liabilities	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Liabilities on Consolidated Balance Sheets
Commodity derivative liabilities subject to a master netting agreement or similar arrangement	$ 5,794	$ (5,794)	$ —
Commodity derivative liabilities not subject to a master netting agreement or similar arrangement	1,007	—	1,007
Total derivative liabilities	$ 6,801	$ (5,794)	$ 1,007

(11) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments, excluding derivatives which are presented in Note 10, were as follows at December 31 (in thousands):

	2019		2018	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [a]	$ 9,777	$ 9,777	$ 20,776	$ 20,776
Restricted cash and equivalents [a]	$ 3,881	$ 3,881	$ 3,369	$ 3,369
Notes payable [b]	$ 349,500	$ 349,500	$ 185,620	$ 185,620
Long-term debt, including current maturities [c]	$ 3,145,839	$ 3,479,367	$ 2,956,578	$ 3,039,108

(a) Carrying value approximates fair value. Cash, cash equivalents, and restricted cash are classified in Level 1 in the fair value hierarchy.
(b) Notes payable consist of commercial paper borrowings. Carrying value approximates fair value due to the short-term length of maturity; since these borrowings are not traded on an exchange, they are classified in Level 2 in the fair value hierarchy.
(c) Long-term debt is valued based on observable inputs available either directly or indirectly for similar liabilities in active markets and therefore is classified in Level 2 in the fair value hierarchy. Carrying amount of long-term debt is net of deferred financing costs.

Cash and Cash Equivalents

Included in cash and cash equivalents is cash, money market mutual funds, and term deposits. As part of our cash management process, excess operating cash is invested in money market mutual funds with our bank. Money market mutual funds are not deposits and are not insured by the U.S. Government, the FDIC, or any other government agency and involve investment risk including possible loss of principal. We believe, however, that the market risk arising from holding these financial instruments is minimal.

Restricted Cash and Equivalents

Restricted cash and cash equivalents represent restricted cash and uninsured term deposits.

Notes Payable and Long-Term Debt

For additional information on our notes payable and long-term debt, see Note 6 and Note 7.

(12) EQUITY

At-the-Market Equity Offering Program

Our ATM equity offering program allows us to sell shares of our common stock with an aggregate value of up to $300 million. The shares may be offered from time to time pursuant to a sales agreement dated August 4, 2017. Shares of common stock are offered pursuant to our shelf registration statement filed with the SEC. During the twelve months ended December 31, 2019, we issued a total of 1,328,332 shares of common stock under the ATM equity offering program for $99 million, net of $1.2 million in issuance costs. As of December 31, 2019, all shares were settled. We did not issue any common shares under the ATM equity offering program during the twelve months ended December 31, 2018 and 2017.

Equity Units

On November 23, 2015, we issued 5.98 million Equity Units for total gross proceeds of $299 million. Each Equity Unit had a stated amount of $50.00 and consisted of (i) a forward purchase contract to purchase the Company’s common stock and (ii) a 1/20, or 5%, undivided beneficial ownership interest in $1,000 principal amount of RSNs due 2028.

On October 29, 2018, we announced the settlement rate for the stock purchase contracts that are components of the Equity Units issued on November 23, 2015. The settlement rate was based upon the minimum settlement rate, as adjusted to account for past dividends, because the average of the closing price per share of BHC common stock on the New York Stock Exchange for the 20 consecutive trading days ending on October 29, 2018 exceeded the threshold appreciation price. Each holder of the Equity Units on that date, following payment of $50.00 for each unit which it holds, received 1.0655 shares of BHC common stock for each such unit. The holders' obligations to make such payments were satisfied with proceeds generated by the successful remarketing on August 17, 2018, of the RSNs that formerly constituted a component of the Equity Units. See Note 6 for additional information.

Upon settlement of all outstanding stock purchase obligations, the Company received gross proceeds of approximately $299 million in exchange for approximately 6.372 million shares of common stock. Proceeds were used to pay down the $250 million senior unsecured notes due January 11, 2019, with the balance used to pay down short-term debt.

Equity Compensation Plans`

Our 2015 Omnibus Incentive Plan allows for the granting of stock, restricted stock, restricted stock units, stock options and performance shares. We had 672,049 shares available to grant at December 31, 2019.

Compensation expense is determined using the grant date fair value estimated in accordance with the provisions of accounting standards for stock compensation and is recognized over the vesting periods of the individual awards. As of December 31, 2019, total unrecognized compensation expense related to non-vested stock awards was approximately $12 million and is expected to be recognized over a weighted-average period of 2 years. Stock-based compensation expense included in Operations and maintenance on the accompanying Consolidated Statements of Income was as follows for the years ended December 31 (in thousands):

	2019	2018	2017
Stock-based compensation expense	$ 12,095	$ 12,390	$ 7,626

Stock Options

The Company has not issued any stock options since 2014 and has 14,000 stock options outstanding at December 31, 2019. The amount of stock options granted during the last three years, and related exercise activity are not material to the Company's consolidated financial statements.

Restricted Stock

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

The shares carry a restriction on the ability to sell the shares until the shares vest. The shares substantially vest over 3 years, contingent on continued employment. Compensation expense related to the awards is recognized over the vesting period.

A summary of the status of the restricted stock and restricted stock units at December 31, 2019, was as follows:

	Restricted Stock	Weighted-Average Grant Date Fair Value
	(in thousands)	
Balance at beginning of period	236	$ 57.50
Granted	92	73.66
Vested	(120)	56.33
Forfeited	(16)	62.02
Balance at end of period	192	$ 65.66

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

	Weighted-Average Grant Date Fair Value	Total Fair Value of Shares Vested
		(in thousands)
2019	$ 73.66	$ 8,438
2018	$ 57.31	$ 6,776
2017	$ 60.63	$ 7,909

As of December 31, 2019, there was $9.0 million of unrecognized compensation expense related to non-vested restricted stock that is expected to be recognized over a weighted-average period of 2.1 years.

Performance Share Plan

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

The performance awards are paid 50% in cash and 50% in common stock. The cash portion accrued is classified as a liability and the stock portion is classified as equity. In the event of a change-in-control, performance awards are paid 100% in cash. If it is determined that a change-in-control is probable, the equity portion of $2.9 million at December 31, 2019 would be reclassified as a liability.

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

			Possible Payout Range of Target	
Grant Date	Performance Period	Target Grant of Shares	Minimum	Maximum
January 1, 2017	January 1, 2017 - December 31, 2019	46	0%	200%
January 1, 2018	January 1, 2018 - December 31, 2020	50	0%	200%
January 1, 2019	January 1, 2019 - December 31, 2021	37	0%	200%

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

	Equity Portion		Liability Portion	
	Shares	Weighted-Average Grant Date Fair Value [(a)]	Shares	Weighted-Average Fair Value at December 31, 2019
	(in thousands)		(in thousands)	
Performance Shares balance at beginning of period	77	$ 57.66	77	
Granted	20	68.72	20	
Forfeited	(4)	64.60	(4)	
Vested	(26)	47.76	(26)	
Performance Shares balance at end of period	67	$ 64.32	67	$ 89.63

(a) The grant date fair values for the performance shares granted in 2019, 2018 and 2017 were determined by Monte Carlo simulation using a blended volatility of 21%, 21% and 23%, respectively, comprised of 50% historical volatility and 50% implied volatility and the average risk-free interest rate of the three-year United States Treasury security rate in effect as of the grant date.

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

	Weighted Average Grant Date Fair Value
December 31, 2019	$ 68.72
December 31, 2018	$ 61.82
December 31, 2017	$ 63.52

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

Performance Period	Year Paid	Stock Issued	Cash Paid	Total Intrinsic Value
January 1, 2016 to December 31, 2018	2019	44	$ 2,860	$ 5,720
January 1, 2015 to December 31, 2017		—	—	—
January 1, 2014 to December 31, 2016		—	—	—

On January 28, 2020, the Compensation Committee of our Board of Directors determined that the Company's total shareholder return for the January 1, 2017 through December 31, 2019 performance period was at the 36.3 percentile of its peer group and confirmed a payout equal to 58.86% of target shares, valued at $2.2 million. The payout was fully accrued at December 31, 2019.

As of December 31, 2019, there was $3.4 million of unrecognized compensation expense related to outstanding performance share plans that is expected to be recognized over a weighted-average period of 1.6 years.

Shareholder Dividend Reinvestment and Stock Purchase Plan

We have a DRSPP under which shareholders may purchase additional shares of common stock through dividend reinvestment and/or optional cash payments at 100% of the recent average market price. We have the option of issuing new shares or purchasing the shares on the open market. We issued new shares until March 1, 2018, after which we began purchasing shares on the open market. At December 31, 2019, there were 214,967 shares of unissued stock available for future offering under the plan.

Preferred Stock

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

Noncontrolling Interest in Subsidiary

Black Hills Colorado IPP owns and operates a 200 MW, combined-cycle natural gas generating facility located in Pueblo, Colorado. In April 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for $216 million to a third-party buyer. Black Hills Electric Generation is the operator of the facility, which is contracted to provide capacity and energy through 2031 to Colorado Electric.

The accounting for a partial sale of a subsidiary in which control is maintained and the subsidiary continues to be consolidated, is specified under ASC 810. The partial sale is required to be recorded as an equity transaction with no resulting gain or loss on the sale. GAAP requires that noncontrolling interests in subsidiaries and affiliates be reported in the equity section of a company's balance sheet. Distributions of net income attributable to noncontrolling interests are due within 30 days following the end of a quarter, but may be withheld as necessary by Black Hills Electric Generation.

Net income available for common stock for the years ended December 31, 2019, 2018 and 2017 was reduced by $14 million, $14 million, and $14 million, respectively, attributable to this noncontrolling interest. The net income allocable to the noncontrolling interest holders is based on ownership interests with the exception of certain agreed upon adjustments.

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

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

	2019	2018
Assets		
Current assets	$ 13,350	$ 13,620
Property, plant and equipment of variable interest entities, net	$ 193,046	$ 199,839
Liabilities		
Current liabilities	$ 6,013	$ 5,174

(13) REGULATORY MATTERS

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

	2019	2018
Regulatory assets		
Deferred energy and fuel cost adjustments [a]	$ 34,088	$ 29,661
Deferred gas cost adjustments [a]	1,540	3,362
Gas price derivatives [a]	3,328	6,201
Deferred taxes on AFUDC [b]	7,790	7,841
Employee benefit plans [c]	115,900	110,524
Environmental [a]	1,454	959
Loss on reacquired debt [a]	24,777	21,001
Renewable energy standard adjustment [a]	1,622	1,722
Deferred taxes on flow through accounting [c]	41,220	31,044
Decommissioning costs [a]	10,670	11,700
Gas supply contract termination [a]	8,485	14,310
Other regulatory assets [a]	20,470	45,910
Total regulatory assets	271,344	284,235
Less current regulatory assets	(43,282)	(48,776)
Regulatory assets, non-current	$ 228,062	$ 235,459
Regulatory liabilities		
Deferred energy and gas costs [a]	$ 17,278	$ 6,991
Employee benefit plan costs and related deferred taxes [c]	43,349	42,533
Cost of removal [a]	166,727	150,123
Excess deferred income taxes [c]	285,438	310,562
TCJA revenue reserve	3,418	18,032
Other regulatory liabilities [c]	20,442	12,553
Total regulatory liabilities	536,652	540,794
Less current regulatory liabilities	(33,507)	(29,810)
Regulatory liabilities, non-current	$ 503,145	$ 510,984

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

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

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

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

Gas Price Derivatives - Our regulated utilities, as allowed or required by state utility commissions, have entered into certain exchange-traded natural gas futures and options to reduce our customers' underlying exposure to fluctuations in gas prices. Gas price derivatives represent our unrealized positions on our commodity contracts supporting our utilities. Gas price derivatives at December 31, 2019 are hedged over a maximum forward term of two years.

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

Employee Benefit Plans - Employee benefit plans include the unrecognized prior service costs and net actuarial loss associated with our defined benefit pension plan and post-retirement benefit plans in regulatory assets rather than in AOCI.

Environmental - Environmental expenditures are costs associated with manufactured gas plant sites. The amortization of this asset is first offset by recognition of insurance proceeds and settlements with other third parties. Any remaining recovery will be requested in future rate filings. Recovery has not yet been approved by the applicable commission or board and therefore, the recovery period is unknown.

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

Renewable Energy Standard Adjustment - The renewable energy standard adjustment is associated with incentives for our Colorado Electric customers to install renewable energy equipment at their location. These incentives are recovered over time with an additional rider charged on customers' bills.

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

Decommissioning Costs - South Dakota Electric and Colorado Electric received approval in 2014 for recovery of the remaining net book values and decommissioning costs of their decommissioned coal plants. In 2018, Arkansas Gas received approval to record Liquefied Natural Gas Plant decommissioning costs in a regulatory asset, with recovery to be determined in a future regulatory filing.

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

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

Deferred Energy and Gas Costs **-** Deferred energy costs and gas costs related to over-recovery of purchased power, transmission and natural gas costs.

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

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

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

TCJA Revenue Reserve - Revenue to be returned to customers as a result of the TCJA. See Note 15 for additional information.

Regulatory Matters

Electric Utilities Regulatory Activity

South Dakota Electric

Settlement

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

FERC Formula Rate

The annual rate determination process is governed by the FERC formula rate protocols established in the filed FERC joint-access transmission tariff. Effective January 1, 2019 the annual revenue requirement increased by $1.9 million and included estimated weighted average capital additions of $31 million for 2018 and 2019 combined. The annual transmission revenue requirement has a true up mechanism that is posted in June of each year.

South Dakota Electric and Wyoming Electric

Renewable Ready

In July 2019, South Dakota Electric and Wyoming Electric received approvals for the Renewable Ready program and related jointly-filed CPCN to construct Corriedale. The wind project will be jointly owned by the two electric utilities to deliver renewable energy for large commercial, industrial and governmental agency customers. In November 2019, South Dakota Electric received approval from the SDPUC to increase the offering under the program by 12.5 MW. The two electric utilities also received a determination from the WPSC to increase the project to 52.5 MW. The $79 million project is expected to be in service by year-end 2020.

Black Hills Wyoming and Wyoming Electric

Wygen 1 FERC Filing

On August 2, 2019, Black Hills Wyoming and Wyoming Electric jointly filed a request with FERC for approval of a new 60 MW PPA. The agreement would fulfill the capacity need for Wyoming Electric at the expiration of the current agreement on December 31, 2022. If approved, Black Hills Wyoming will continue to deliver 60 MW of energy to Wyoming Electric from its Wygen I power plant starting January 1, 2023, and continuing for an additional 20 years to December 31, 2042. On December 23, 2019, the Company filed a response to questions from the FERC and awaits a decision from FERC.

Wyoming Electric

Blockchain Tariff

On April 30, 2019, the WPSC approved Wyoming Electric's application for a new Blockchain Interruptible Service Tariff. The utility has partnered with the economic development organization for City of Cheyenne and Laramie County to actively recruit blockchain customers to the state. This tariff is complementary to recently enacted Wyoming legislation supporting the development of blockchain within the state.

PCA Settlement

On October 31, 2018, Wyoming Electric received approval from the WPSC for a comprehensive, multi-year settlement regarding its PCA Application filed earlier in 2018. Wyoming Electric's PCA permits the recovery of costs associated with fuel, purchased electricity and other specified costs, including the portion of the company's energy that is delivered from the Wygen I PPA with Black Hills Wyoming. Wyoming Electric was to provide a total of $7.0 million in customer credits through the PCA mechanism in 2018, 2019 and 2020 to resolve all outstanding issues relating to its current and prior PCA filings. The settlement also stipulated the adjustment for the variable cost segment of the Wygen I PPA with Wyoming Electric will escalate by 3.0% annually through 2022, providing price certainty for Wyoming Electric and its customers.

Gas Utilities Regulatory Activity

Arkansas Gas

Rate Review

On October 5, 2018, Arkansas Gas received approval from the APSC for a general rate increase. The new rates were to generate approximately $12 million of new annual revenue. The APSC's approval also allowed Arkansas Gas to include $11 million of revenue that was being collected through certain rider mechanisms in the new base rates. The new revenue increase was based on a return on equity of 9.61% and a capital structure of 49.1% equity and 50.9% debt. New rates, inclusive of customer benefits related to the TCJA, were effective October 15, 2018.

Colorado Gas

Jurisdictional Consolidation and Rate Review

On February 1, 2019, Colorado Gas filed a rate review with the CPUC requesting approval to consolidate rates, tariffs, and services of its two existing gas distribution territories. The rate review requested $2.5 million in new revenue to recover investments in safety, reliability and system integrity. Colorado Gas also requested a new rider mechanism to recover future safety and integrity investments in its system. On December 27, 2019, the ALJ issued a recommended decision denying the company's plan to consolidate rate territories and recommending a rate decrease. Colorado Gas has filed exceptions to the ALJ's recommended decision. A decision by the CPUC is expected by the end of March 2020. Legal consolidation was previously approved by the CPUC in late 2018 and completed in early 2019.

Nebraska Gas

Jurisdictional Consolidation and Rate Review

On October 29, 2019, Nebraska Gas received approval from the NPSC to merge its two gas distribution companies. Legal consolidation was effective January 1, 2020, and a rate review is expected to be filed by mid-year 2020 to consolidate the rates, tariffs and services.

SSIR

On June 1, 2018, Nebraska Gas Distribution filed an application with the NPSC requesting a continuation of the SSIR beyond the expiration date of October 31, 2019. On September 5, 2018, the NPSC approved continuation of the SSIR tariff to December 31, 2020. The SSIR provides approximately $6.0 million of revenue annually on investments made prior to January 1, 2018, with investments after that date to be recovered through other methods. If a base rate review is filed prior to expiration of the rider, that rate request will include the remaining investment to be recovered.

On October 2, 2017, Nebraska Gas Distribution filed with the NPSC requesting recovery of $6.8 million, which includes $0.3 million of increased annual revenue related to system safety and integrity expenditures on projects for the period of 2012 through 2017. This SSIR tariff was approved by the NPSC in January 2018, and went into effect on February 1, 2018.

Wyoming Gas

Jurisdictional Consolidation and Rate Review

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

(14) LEASES

Lessee

We lease from third parties certain office and operation center facilities, communication tower sites, equipment, and materials storage. Our leases have remaining terms ranging from less than 1 year to 36 years, including options to extend that are reasonably certain to be exercised.

The components of lease expense for the year ended December 31 were as follows (in thousands) :

	Income Statement Location		2019
Operating lease cost	Operations and maintenance	$	1,456
Finance lease cost:			
Amortization of right-of-use asset	Depreciation, depletion and amortization		100
Interest on lease liabilities	Interest expense incurred net of amounts capitalized (including amortization of debt issuance costs, premiums and discounts)		19
Total lease cost		$	1,575

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

	Balance Sheet Location		2019
Assets:			
Operating lease assets	Other assets, non-current	$	4,629
Finance lease assets	Other assets, non-current		465
Total lease assets		$	5,094
Liabilities:			
Current:			
Operating leases	Accrued liabilities	$	1,179
Finance lease	Accrued liabilities		109
Noncurrent:			
Operating leases	Other deferred credits and other liabilities		3,821
Finance lease	Other deferred credits and other liabilities		364
Total lease liabilities		$	5,473

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

		2019
Cash paid included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$	1,263
Operating cash flows from finance lease	$	19
Financing cash flows from finance lease	$	93
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases	$	2,801
Finance lease	$	67

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

	2019
Weighted average remaining lease term (years):	
Operating leases	8 years
Finance lease	4 years
Weighted average discount rate:	
Operating leases	4.27%
Finance lease	4.19%

As of December 31, 2019, scheduled maturities of lease liabilities for future years were as follows (in thousands):

	Operating Leases	Finance Lease	Total
2020	1,018	126	1,144
2021	865	126	991
2022	743	126	869
2023	718	126	844
2024	714	10	724
Thereafter	2,009	—	2,009
Total lease payments [(a)]	$ 6,067	$ 514	$ 6,581
Less imputed interest	1,067	41	1,108
Present value of lease liabilities	$ 5,000	$ 473	$ 5,473

(a) Lease payments exclude payments to landlords for common area maintenance, real estate taxes, and insurance.

As previously disclosed in Note 14 of the Notes to the Consolidated Financial Statements in our 2018 Annual Report on Form 10-K, prior to the adoption of ASU 2016-02, *Leases (Topic 842),* the future minimum payments required under operating lease agreements as of December 31, 2018 were as follows (in thousands):

	Operating Leases
2019	$ 1,052
2020	464
2021	344
2022	224
2023	216
Thereafter	1,776
Total lease payments	$ 4,076

Lessor

We lease to third parties certain generating station ground leases, communication tower sites, and a natural gas pipeline. These leases have remaining terms ranging from less than one year to 35 years.

The components of lease revenue for the year ended December 31 were as follows (in thousands):

	Income Statement Location	2019
Operating lease income	Revenue	$ 2,306

As of December 31, 2019, scheduled maturities of operating lease payments to be received in future years were as follows (in thousands):

		Operating Leases
2020		2,227
2021		1,857
2022		1,793
2023		1,799
2024		1,743
Thereafter		53,739
Total lease receivables	$	63,158

(15) INCOME TAXES

TCJA

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the TCJA. The TCJA reduced the U.S. federal corporate tax rate from 35% to 21%. As such, the Company remeasured the deferred income taxes at the 21% federal tax rate as of December 31, 2017. The entities subject to regulatory construct have made their best estimate regarding the probability of settlements of net regulatory liabilities established pursuant to the TCJA. The amount of the settlements may change based on decisions and actions by the federal and state utility commissions, which could have a material impact on the Company's future results of operations, cash flows or financial position. As a result of the revaluation at December 31, 2017, deferred tax assets and liabilities were reduced by approximately $309 million. Of the $309 million, approximately $301 million is related to our regulated utilities and is reclassified to a regulatory liability. During the year ended December 31, 2018 we recorded approximately $11 million of additional regulatory liability associated with TCJA related items primarily related to property, completing the revaluation of deferred taxes pursuant to the TCJA. A majority of the excess deferred taxes are subject to the average rate assumption method, as prescribed by the IRS, and will generally be amortized as a reduction of customer rates over the remaining lives of the related assets. As of December 31, 2019, the Company has amortized $6.5 million of the regulatory liability. The portion that was eligible for amortization under the average rate assumption method in 2019, 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.

Tax benefit related to legal entity restructuring

As part of the Company's ongoing efforts to continue to integrate the legal entities that the Company has acquired in recent years, certain legal entity restructuring transactions occurred on March 31, 2018 and December 31, 2018. As a result of these transactions, additional deferred income tax assets of $73 million, related to goodwill that is amortizable for tax purposes, were recorded and deferred tax benefits of $73 million were recorded to income tax benefit (expense) on the Consolidated Statements of Income. Due to this being a common control transaction, it had no effect on the other assets and liabilities of these entities.

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

	2019	2018	2017
Current:			
Federal	$ (8,578)	$ 325	$ (6,193)
State	138	247	(1,432)
	(8,440)	572	(7,625)
Deferred:			
Federal	34,551	(25,022)	76,522
State	3,469	783	4,470
	38,020	(24,239)	80,992
	$ 29,580	$ (23,667)	$ 73,367

Included in discontinued operations is a tax benefit of $2.6 million and $8.4 million for 2018 and 2017, respectively.

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

	2019	2018
Deferred tax assets:		
Regulatory liabilities	$ 89,754	$ 92,966
State tax credits	23,261	20,466
Federal net operating loss	120,624	139,371
State net operating loss	13,537	16,647
Partnership	14,030	16,032
Credit Carryovers	27,139	23,124
Other deferred tax assets[a]	33,395	39,349
Less: Valuation allowance	(12,063)	(11,809)
Total deferred tax assets	309,677	336,146
Deferred tax liabilities:		
Accelerated depreciation, amortization and other property-related differences	(533,292)	(529,338)
Regulatory assets	(23,586)	(32,324)
Goodwill [b]	(15,875)	(602)
State deferred tax liability	(72,911)	(64,095)
Other deferred tax liabilities	(24,732)	(21,118)
Total deferred tax liabilities	(670,396)	(647,477)
Net deferred tax liability	$ (360,719)	$ (311,331)

(a) Other deferred tax assets consist primarily of alternative minimum tax credit and federal research and development credits. No single item exceeds 5% of the total net deferred tax liability.
(b) Legal entity restructuring - see above.

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

	2019	2018	2017
Federal statutory rate	21.0%	21.0 %	35.0%
State income tax (net of federal tax effect)	1.5	2.3	0.9
Non-controlling interest [(a)]	(1.2)	(1.3)	(1.8)
Tax credits	(3.9)	(2.0)	(1.7)
Flow-through adjustments [(b)]	(2.4)	(1.6)	(1.1)
Jurisdictional consolidation project [(d)]	—	(28.5)	—
Other tax differences	(1.6)	(0.1)	(2.6)
TCJA corporate rate reduction [(c)]	—	1.6	(2.7)
Amortization of excess deferred income tax expense [(e)]	(1.2)	(0.7)	—
	12.2%	(9.3)%	26.0%

(a) The effective tax rate reflects the income attributable to the noncontrolling interest in Black Hills Colorado IPP for which a tax provision was not recorded.
(b) Flow-through adjustments related primarily to accounting method changes for tax purposes that allow us to take a current tax deduction for repair costs and certain indirect costs. We recorded a deferred income tax liability in recognition of the temporary difference created between book and tax treatment and flowed the tax benefit through to tax expense. A regulatory asset was established to reflect the recovery of future increases in taxes payable from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record tax benefits consistent with the flow-through method.
(c) On December 22, 2017, the TCJA was signed into law reducing the federal corporate rate from 35% to 21% effective January 1, 2018. The 2017 effective tax rate reduction reflects the revaluation of deferred income taxes associated with non-regulated operations required by the change. During the year ended December 31, 2018, we recorded $4.0 million of additional tax expense associated with changes in the prior estimated impacts of TCJA related items. During the year ended December 31, 2017, we recorded $7.6 million of tax benefit resulting from revaluation of net deferred tax liabilities in accordance with ASC 740 and the enactment of the TCJA on December 22, 2017.
(d) Legal entity restructuring - see above.
(e) Primarily TCJA - see above.

At December 31, 2019, we have federal and state NOL carryforwards that will expire at various dates as follows (in thousands):

		Amounts	Expiration Dates		
Federal Net Operating Loss Carryforward	$	575,457	2022	to	2037
State Net Operating Loss Carryforward [(a)]	$	224,716	2020	to	2040

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

As of December 31, 2019, we had a $0.5 million valuation allowance against the state NOL carryforwards. Our 2019 analysis of the ability to utilize such NOLs resulted in no increase in the valuation allowance. If the valuation allowance is adjusted due to higher or lower than anticipated utilization of the NOLs, the offsetting amount will affect tax expense.

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

	Changes in Uncertain Tax Positions	
Beginning balance at January 1, 2017	$	3,592
Additions for prior year tax positions		358
Reductions for prior year tax positions		(5,713)
Additions for current year tax positions		5,026
Settlements		—
Ending balance at December 31, 2017		3,263
Additions for prior year tax positions		251
Reductions for prior year tax positions		(417)
Additions for current year tax positions		486
Settlements		—
Ending balance at December 31, 2018		3,583
Additions for prior year tax positions		446
Reductions for prior year tax positions		(862)
Additions for current year tax positions		998
Settlements		—
Ending balance at December 31, 2019	$	4,165

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $0.3 million.

We recognized no interest expense associated with income taxes for the years ended December 31, 2019, December 31, 2018 and December 31, 2017. We had no accrued interest (before tax effect) associated with income taxes at December 31, 2019 and December 31, 2018.

The Company is subject to federal income tax as well as income tax in various state and local jurisdictions. Black Hills Gas, Inc. and subsidiaries, which filed a separate consolidated tax return from BHC and subsidiaries through March 31, 2018, is under examination by the IRS for 2014. BHC is no longer subject to examination for tax years prior to 2016.

As of December 31, 2019, we do not have any tax positions for which it is reasonably possible that the total amount of unrecognized tax benefits will significantly increase or decrease on or before December 31, 2020.

State tax credits have been generated and are available to offset future state income taxes. At December 31, 2019, we had the following state tax credit carryforwards (in thousands):

State Tax Credit Carryforwards			Expiration Year		
ITC	$	23,060	2023	to	2041
Research and development	$	201		No expiration	

As of December 31, 2019, we had a $9 million valuation allowance against the state tax credit carryforwards. Ultimate usage of these credits depends upon our future tax filings. If the valuation allowance is adjusted due to higher or lower than anticipated utilization of the state tax credit carryforwards, the offsetting amount will affect tax expense.

(16) OTHER COMPREHENSIVE INCOME

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

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

	Location on the Consolidated Statements of Income	Amount Reclassified from AOCI December 31, 2019	Amount Reclassified from AOCI December 31, 2018
Gains and (losses) on cash flow hedges:			
Interest rate swaps	Interest expense	$ (2,851)	$ (2,851)
Commodity contracts	Fuel, purchased power and cost of natural gas sold	417	(130)
		(2,434)	(2,981)
Income tax	Income tax benefit (expense)	611	630
Total reclassification adjustments related to cash flow hedges, net of tax		$ (1,823)	$ (2,351)
Amortization of components of defined benefit plans:			
Prior service cost	Operations and maintenance	$ 77	$ 178
Actuarial gain (loss)	Operations and maintenance	(745)	(2,487)
		(668)	(2,309)
Income tax	Income tax benefit (expense)	(453)	543
Total reclassification adjustments related to defined benefit plans, net of tax		$ (1,121)	$ (1,766)
Total reclassifications		$ (2,944)	$ (4,117)

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

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

	Derivatives Designated as Cash Flow Hedges			
	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
As of December 31, 2017	$ (19,581)	$ (518)	$ (21,103)	$ (41,202)
Other comprehensive income (loss)				
before reclassifications	—	755	2,155	2,910
Amounts reclassified from AOCI	2,252	99	1,766	4,117
Reclassification to regulatory asset	—	—	6,519	6,519
Reclassification of certain tax effects from AOCI	22	(8)	726	740
As of December 31, 2018	$ (17,307)	$ 328	$ (9,937)	$ (26,916)

(17) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Years ended December 31,	2019	2018	2017
		(in thousands)	
Non-cash investing activities and financing from continuing operations -			
Accrued property, plant and equipment purchases at December 31	$ 91,491	$ 69,017	$ 28,191
Increase (decrease) in capitalized assets associated with asset retirement obligations	$ 5,044	$ 2,625	$ 3,198
Cash (paid) refunded during the period for continuing operations-			
Interest (net of amounts capitalized)	$ (131,774)	$ (137,965)	$ (132,428)
Income taxes (paid) refunded	$ 4,682	$ (14,730)	$ 1,775

(18) EMPLOYEE BENEFIT PLANS

Defined Contribution Plans

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

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

Defined Benefit Pension Plan

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

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

The expected rate of return on the Pension Plan assets is determined by reviewing the historical and expected returns of both equity and fixed income markets, taking into account asset allocation, the correlation between asset class returns, and the mix of active and passive investments. The Pension Plan utilizes a dynamic asset allocation where the target range to return-seeking and liability-hedging assets is determined based on the funded status of the Plan. As of December 31, 2019, the expected rate of return on pension plan assets was based on the targeted asset allocation range of 29% to 37% return-seeking assets and 63% to 71% liability-hedging assets.

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

Plan Assets

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

	2019	2018
Equity	20%	17%
Real estate	3	4
Fixed income	71	71
Cash	1	3
Hedge funds	5	5
Total	100%	100%

Supplemental Non-qualified Defined Benefit Plans

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

Non-pension Defined Benefit Postretirement Healthcare Plan

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

Plan Assets

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

Plan Contributions

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

	2019	2018
Defined Contribution Plan		
Company retirement contributions	$ 9,714	$ 8,766
Company matching contributions	$ 14,558	$ 13,559

	2019	2018
Defined Benefit Plans		
Defined Benefit Pension Plan	$ 12,700	$ 12,700
Non-Pension Defined Benefit Postretirement Healthcare Plan	$ 7,033	$ 5,298
Supplemental Non-Qualified Defined Benefit Plans	$ 2,344	$ 2,073

While we do not have required contributions, we expect to make approximately $13 million in contributions to our Pension Plan in 2020.

Fair Value Measurements

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect their placement within the fair value hierarchy levels.

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

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

Pension Plan	December 31, 2018					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV (a)	Total Investments
AXA Equitable General Fixed Income	$ —	$ 1,867	$ —	$ 1,867	$ —	$ 1,867
Common Collective Trust - Cash and Cash Equivalents	—	9,923	—	9,923	—	9,923
Common Collective Trust - Equity	—	67,457	—	67,457	—	67,457
Common Collective Trust - Fixed Income	—	279,148	—	279,148	—	279,148
Common Collective Trust - Real Estate	—	67	—	67	13,551	13,618
Hedge Funds	—	—	—	—	18,783	18,783
Total investments measured at fair value	$ —	$ 358,462	$ —	$ 358,462	$ 32,334	$ 390,796

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

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

Non-pension Defined Benefit Postretirement Healthcare Plan	December 31, 2018				
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	Total Investments
Cash and Cash Equivalents	$ 4,873	$ —	$ —	$ 4,873	$ 4,873
Equity Securities	1,005	—	—	1,005	1,005
Intermediate-term Bond	—	2,284	—	2,284	2,284
Total investments measured at fair value	$ 5,878	$ 2,284	$ —	$ 8,162	$ 8,162

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

AXA Equitable General Fixed Income Fund: This fund is a diversified portfolio, primarily composed of fixed income instruments. Assets are invested in long-term holdings, such as commercial, agricultural and residential mortgages, publicly traded and privately placed bonds and real estate as well as short-term bonds. Fair values of mortgage loans are measured by discounting future contractual cash flows to be received on the mortgage loans using interest rates of loans with similar characteristics. The discount rate is derived from taking the appropriate U.S. Treasury rate with a like term. The fair value of public fixed maturity securities are generally based on prices obtained from independent valuation service providers with reasonableness prices compared with directly observable market trades. The fair value of privately placed securities are determined using a discounted cash flow model. These models use observable inputs with a discount rate based upon the average of spread surveys collected from private market intermediaries and industry sector of the issuer. The Plan's investments in the AXA Equitable General Fixed Income Fund are categorized as Level 2.

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

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

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

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

Hedge Funds: These funds represent investments in other investment funds that seek a return utilizing a number of diverse investment strategies. The strategies, when combined, aim to reduce volatility and risk while attempting to deliver positive returns under all market conditions. Amounts are reported on a one-month lag. The fair value of hedge funds is determined using net asset value per share based on the fair value of the hedge fund's underlying investments. 20% of the shares may be redeemed at the end of each month with a 10-day notice and full redemptions are available at the end of each quarter with 30-day notice and is limited to a percentage of the total net assets value of the fund. The net asset values are based on the fair value of each fund's underlying investments. There are no unfunded commitments related to these hedge funds.

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

Equity Securities: These represent investments in a combination of equity positions for mainly large cap core allocation and Exchange Trade Funds (ETFs) for diversification into the other sectors of the economy. ETFs are a basket of securities traded like individual stocks on the exchange. Value of equity securities held at year end are based on published market quotations of active markets. The ETF funds can be redeemed on a daily basis at their market price and have no redemption restrictions. As shares held reflect quoted prices in an active market, they are categorized as Level 1.

Intermediate-term Bond: This is comprised of a diversified pool of high quality, individual municipal bonds. Pricing is evaluated using multi-dimensional relational models, as well as a series of matrices using Standard Inputs, including Municipal Securities Rule Making Board (MSRB) reported trades and material event notices, plus Municipal Market Data (MMD) benchmark yields and new issue data. As the models use observable inputs and standard data, the investments are categorized as Level 2.

Other Plan Information

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

Benefit Obligations

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plan	
As of December 31 (in thousands),	2019	2018	2019	2018	2019	2018
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 445,381	$ 474,725	$ 43,010	$ 45,112	$ 60,817	$ 69,339
Service cost	5,383	6,834	4,995	1,764	1,815	2,291
Interest cost	17,374	15,470	1,295	1,170	2,247	2,085
Actuarial (gain) loss	56,384	(31,340)	7,132	(2,963)	5,976	(9,045)
Benefits paid	(39,146)	(20,308)	(2,344)	(2,073)	(7,033)	(5,298)
Plan participants' contributions	—	—	—	—	1,455	1,445
Projected benefit obligation at end of year	$ 485,376	$ 445,381	$ 54,088	$ 43,010	$ 65,277	$ 60,817

Employee Benefit Plan Assets

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plan [(a)]	
As of December 31 (in thousands),	2019	2018	2019	2018	2019	2018
Change in fair value of plan assets:						
Beginning fair value of plan assets	$ 390,796	$ 416,343	$ —	$ —	$ 8,162	$ 8,621
Investment income (loss)	69,934	(17,939)	—	—	260	(149)
Employer contributions	12,700	12,700	2,344	2,073	5,461	3,543
Retiree contributions	—	—	—	—	1,455	1,445
Benefits paid	(39,146)	(20,308)	(2,344)	(2,073)	(7,033)	(5,298)
Ending fair value of plan assets	$ 434,284	$ 390,796	$ —	$ —	$ 8,305	$ 8,162

(a) Assets of VEBA trusts.

The funded status of the plans and the amounts recognized in the Consolidated Balance Sheets at December 31 consist of (in thousands):

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plan	
	2019	2018	2019	2018	2019	2018
Regulatory assets	$ 88,471	$ 82,919	$ —	$ —	$ 11,670	$ 6,655
Current liabilities	$ —	$ —	$ 1,420	$ 1,463	$ 4,802	$ 3,885
Non-current assets	$ —	$ —	$ —	$ —	$ —	$ 249
Non-current liabilities	$ 51,093	$ 54,585	$ 51,243	$ 41,547	$ 52,136	$ 49,015
Regulatory liabilities	$ 3,524	$ 4,620	$ —	$ —	$ 4,088	$ 5,207

Accumulated Benefit Obligation

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plan	
As of December 31 (in thousands)	2019	2018	2019	2018	2019	2018
Accumulated Benefit Obligation	$ 470,615	$ 428,851	$ 49,241	$ 40,530	$ 65,277	$ 60,817

Components of Net Periodic Expense

Net periodic expense consisted of the following for the year ended December 31 (in thousands):

	Defined Benefit Pension Plan			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plan		
	2019	2018	2017	2019	2018	2017	2019	2018	2017
Service cost	$ 5,383	$ 6,834	$ 7,034	$ 4,995	$ 1,764	$ 1,546	$ 1,815	$ 2,291	$ 2,300
Interest cost	17,374	15,470	15,520	1,295	1,170	1,276	2,247	2,085	2,141
Expected return on assets	(24,401)	(24,741)	(24,517)	—	—	—	(230)	(315)	(315)
Net amortization of prior service cost	26	58	58	2	2	2	(398)	(398)	(411)
Recognized net actuarial loss (gain)	3,763	8,632	4,007	535	1,000	1,001	—	216	499
Net periodic expense	$ 2,145	$ 6,253	$ 2,102	$ 6,827	$ 3,936	$ 3,825	$ 3,434	$ 3,879	$ 4,214

For the years ended December 31, 2019 and 2018, service costs were recorded in Operations and maintenance expense while non-service costs were recorded in Other expense on the Consolidated Statements of Income. For the year ended December 31, 2017, service costs and non-service costs were recorded in Operations and maintenance expense. Because non-service costs were not considered material for the year ended December 31, 2017, they were not reclassified on the Consolidated Statements of Income.

AOCI

For defined benefit plans, amounts included in AOCI, after-tax, that have not yet been recognized as components of net periodic benefit cost at December 31 were as follows (in thousands):

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plan	
	2019	2018	2019	2018	2019	2018
Net (gain) loss	$ 5,322	$ 11,967	$ 9,893	$ 4,668	$ 90	$ 860
Prior service cost (gain)	—	1	2	3	(230)	(317)
Reclassification of certain tax effects from AOCI	—	(594)	—	(87)	—	(45)
Reclassification to regulatory asset	—	(5,600)	—	—	—	(919)
Total AOCI	$ 5,322	$ 5,774	$ 9,895	$ 4,584	$ (140)	$ (421)

Assumptions

	Defined Benefit Pension Plan			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plan		
Weighted-average assumptions used to determine benefit obligations:	2019	2018	2017	2019	2018	2017	2019	2018	2017
Discount rate	3.27%	4.40%	3.71%	3.14%	4.34%	3.56%	3.15%	4.28%	3.60%
Rate of increase in compensation levels	3.49%	3.52%	3.43%	5.00%	5.00%	5.00%	N/A	N/A	N/A

	Defined Benefit Pension Plan			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plan		
Weighted-average assumptions used to determine net periodic benefit cost for plan year:	2019	2018	2017	2019	2018	2017	2019	2018	2017
Discount rate [(a)]	4.40%	3.71%	4.27%	4.34%	3.67%	4.02%	4.28%	3.60%	4.05%
Expected long-term rate of return on assets [(b)]	6.00%	6.25%	6.75%	N/A	N/A	N/A	3.00%	3.93%	3.88%
Rate of increase in compensation levels	3.52%	3.43%	3.47%	5.00%	5.00%	5.00%	N/A	N/A	N/A

(a) The estimated discount rate for the Defined Benefit Pension Plan is 3.27% for the calculation of the 2020 net periodic pension costs.
(b) The expected rate of return on plan assets is 5.25% for the calculation of the 2020 net periodic pension cost.

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

	2019	2018
Trend Rate - Medical		
Pre-65 for next year - All Plans	6.40%	6.70%
Pre-65 Ultimate trend rate - Black Hills Corp	4.50%	4.50%
Trend Year	2027	2027
Post-65 for next year - All Plans	4.92%	4.94%
Post-65 Ultimate trend rate - Black Hills Corp	4.50%	4.50%
Trend Year	2028	2026

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

	Defined Benefit Pension Plan	Supplemental Non-qualified Defined Benefit Plans	Non-pension Defined Benefit Postretirement Healthcare Plan
2020	$ 24,586	$ 1,420	$ 5,919
2021	$ 25,774	$ 1,786	$ 5,974
2022	$ 26,728	$ 2,167	$ 5,790
2023	$ 27,795	$ 2,223	$ 5,521
2024	$ 28,547	$ 2,412	$ 5,329
2025-2029	$ 145,426	$ 14,689	$ 23,030

(19) COMMITMENTS AND CONTINGENCIES

Power Purchase and Transmission Services Agreements

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

- Colorado Electric's PPA with PRPA to purchase up to 60 MW of wind energy upon construction of a new wind project, which is expected in mid-2020. This agreement will expire May 31, 2030.
- Colorado Electric's PPA with PRPA to purchase 25 MW of unit contingent energy. This agreement will expire June 30, 2024.
- South Dakota Electric's PPA with PacifiCorp, expiring December 31, 2023, for the purchase of 50 MW of electric capacity and energy from PacifiCorp's system. The price paid for the capacity and energy is based on the operating costs of one of PacifiCorp's coal-fired electric generating plants.
- South Dakota Electric's firm point-to-point transmission service agreement with PacifiCorp expiring December 31, 2023. The agreement provides 50 MW of capacity and energy to be transmitted annually by PacifiCorp.
- South Dakota Electric's PPA with PRPA to purchase up to 12 MW of wind energy through PRPA's agreement with Silver Sage. This agreement will expire September 30, 2029.
- Wyoming Electric's PPA with Happy Jack, expiring September 3, 2028, provides up to 30 MW of wind energy. Under a separate intercompany agreement, Wyoming Electric sells 50% of the facility output to South Dakota Electric.
- Wyoming Electric's PPA with Silver Sage, expiring September 30, 2029, provides up to 30 MW of wind energy. Under a separate intercompany agreement, Wyoming Electric sells 20 MW of energy from Silver Sage to South Dakota Electric.

- Black Hills Wyoming sold its CTII 40 MW natural gas-fired generating unit to the City of Gillette, Wyoming on September 3, 2014. Under the terms of the sale, Black Hills Wyoming entered into ancillary agreements to operate CTII, provide use of shared facilities including a ground lease and dispatch generation services. In addition, the agreement includes a 20-year economy energy PPA that contains a sharing arrangement in which the parties share the savings of wholesale power purchases made when market power prices are less than the cost of operating the generating unit.

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

	2019	2018	2017
Colorado Electric PPA with PRPA - Unit Contingent Energy	$ 1,802	$ —	$ —
Colorado Electric PPA Busch Ranch I [(a)]	$ —	$ —	$ 1,966
South Dakota Electric PPA with PacifiCorp	$ 7,477	$ 13,681	$ 13,218
South Dakota Electric Transmission services agreement with PacifiCorp	$ 1,741	$ 1,742	$ 1,671
South Dakota Electric PPA with PRPA	$ 688	$ 223	$ —
Wyoming Electric PPA with Happy Jack	$ 3,936	$ 3,884	$ 3,846
Wyoming Electric PPA with Silver Sage	$ 5,366	$ 5,376	$ 4,934

(a) On December 11, 2018, Black Hills Electric Generation purchased a 50% ownership interest of the Busch Ranch I. Black Hills Electric Generation and Colorado Electric now collectively own 100% of the wind farm.

Power Purchase Agreements - Related Party

On November 26, 2019, Black Hills Electric Generation completed and placed in service Busch Ranch II. Black Hills Electric Generation provides the wind energy generated from Busch Ranch II to Colorado Electric under a new PPA, which expires in November 2044.

On December 11, 2018, Black Hills Electric Generation purchased a 50% ownership interest in Busch Ranch I. Black Hills Electric Generation provides its 14.5 MW share of energy from the wind farm to Colorado Electric through a PPA, which expires in October 2037.

Colorado Electric's PPA with Black Hills Colorado IPP expiring on December 31, 2031, provides 200 MW of power to Colorado Electric from Black Hills Colorado IPP's combined-cycle turbines. Effective January 1, 2019, we changed how we account for this PPA at the segment level and now recognize on an accrual basis, rather than a finance lease. See Note 5 for additional information.

Other Gas Supply Agreements

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

Purchase Commitments

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

Our Gas Utilities segment has commitments to purchase physical quantities of natural gas under contracts indexed to various forward natural gas price curves. A portion of our gas purchases are purchased under evergreen contracts and are therefore, for purposes of this disclosure, carried out for 60 days. At December 31, 2019, the long-term commitments to purchase quantities of natural gas under contracts indexed to the following forward indices were as follows (in MMBtus):

	NNG-Ventura	NWPL-Wyoming
2020	3,660,000	1,520,000
2021	3,650,000	1,510,000
2022	1,810,000	1,510,000
2023	0	1,510,000
2024	0	910,000
Thereafter	0	0

Purchases under these contracts totaled $6.7 million, $27 million and $65 million for 2019, 2018 and 2017, respectively.

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

	Power purchase and transmission services agreements	Natural gas transportation and storage agreements
2020	$ 25,476	$ 156,297
2021	$ 11,678	$ 148,149
2022	$ 11,678	$ 122,340
2023	$ 11,678	$ 93,905
2024	$ 2,738	$ 51,360
Thereafter	$ —	$ 126,147

Future Purchase Agreement - Related Party

Wyoming Electric has a PPA with Black Hills Wyoming expiring on December 31, 2022, which provides 60 MW of unit-contingent capacity and energy from Black Hills Wyoming's Wygen I facility. On August 2, 2019, Black Hills Wyoming and Wyoming Electric jointly filed a request with FERC for approval of a new 60 MW PPA. The agreement would fulfill the capacity need for Wyoming Electric at the expiration of the current agreement on December 31, 2022. If approved, Black Hills Wyoming will continue to deliver 60 MW of energy to Wyoming Electric from its Wygen I power plant starting January 1, 2023, and continuing for an additional 20 years to December 31, 2042. On December 23, 2019, the Company filed a response to questions from the FERC and awaits a decision from FERC.

Power Sales Agreements

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

- During periods of reduced production at Wygen III in which MDU owns a portion of the capacity, or during periods when Wygen III is off-line, South Dakota Electric will provide MDU with 25 MW from our other generation facilities or from system purchases with reimbursement of costs by MDU. This agreement expires January 31, 2023.

- South Dakota Electric has an agreement to provide MDU capacity and energy up to a maximum of 50 MW in excess of Wygen III ownership. This agreement expires December 31, 2023.

- During periods of reduced production at Wygen III in which the City of Gillette owns a portion of the capacity, or during periods when Wygen III is off-line, South Dakota Electric will provide the City of Gillette with its first 23 MW from our other generating facilities or from system purchases with reimbursement of costs by the City of Gillette. Under this agreement which is renewed annually on September 3, South Dakota Electric will also provide the City of Gillette their operating component of spinning reserves.

- South Dakota Electric has an amended agreement, effective January 1, 2019, to supply up to 20 MW of energy and capacity to MEAN under a contract that expires May 31, 2028. The contract terms are from June 1 through May 31 for each interval listed below. This contract is unit-contingent based on the availability of our Neil Simpson II and Wygen III plants, with decreasing capacity purchased over the term of the agreement. The unit-contingent capacity amounts from Wygen III and Neil Simpson II are as follows:

Contract Years	Total Contract Capacity	Contingent Capacity Amounts on Wygen III	Contingent Capacity Amounts on Neil Simpson II
2019-2020	15 MW	10 MW	5 MW
2020-2022	15 MW	7 MW	8 MW
2022-2023	15 MW	8 MW	7 MW
2023-2028	10 MW	5 MW	5 MW

- South Dakota Electric has an agreement that expires December 31, 2021 to provide 50 MW of energy to Macquarie Energy, LLC during heavy and light load timing intervals.

Reimbursement Agreement

We have a reimbursement agreement in place with Wells Fargo on behalf of Wyoming Electric for the 2009A bonds of $10 million due in 2027 and the 2009B bonds of $7.0 million due in 2021. In the case of default, we hold the assumption of liability for drawings on Wyoming Electric's Letter of Credit attached to these bonds.

Environmental Matters

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

Reclamation Liability

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

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

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

See Note 8 for additional information.

Manufactured Gas Processing

In 2008, we acquired whole and partial liabilities for former manufactured gas processing sites in Nebraska and Iowa which were previously used to convert coal to natural gas. The acquisition provided for an insurance recovery, now valued at $1.1 million recorded in Other assets, non-current on our Consolidated Balance Sheets, which will be used to help offset remediation costs. We also have a $1.5 million regulatory asset for manufactured gas processing sites; see Note 13 for additional information.

As of December 31, 2019, our estimated liabilities for Iowa's manufactured gas processing site currently range from approximately $2.6 million to $10 million for which we had $2.6 million accrued for remediation of the site as of December 31, 2019 included in Other deferred credits and other liabilities on our Consolidated Balance Sheets. The remediation cost estimate could change materially due to results of further investigations, actions of environmental agencies or the financial viability of other responsible parties.

For additional information, see Environmental Matters in Item 1 of this Annual Report on Form 10-K.

Legal Proceedings

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

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

(20) GUARANTEES

We have entered into various agreements providing financial or performance assurance to third parties on behalf of certain of our subsidiaries. The agreements include indemnification for reclamation and surety bonds and a contract performance guarantee.

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

Nature of Guarantee	Maximum Exposure at December 31, 2019	Expiration
Indemnification for subsidiary reclamation/surety bonds [(a)]	$ 55,527	Ongoing
Contract performance guarantee [(b)]	46,831	May 2020
	$ 102,358	

(a) We have guarantees in place for reclamation and surety bonds for our subsidiaries. The guarantees were entered into in the normal course of business. To the extent liabilities are incurred as a result of activities covered by the surety bonds, such liabilities are included in our Consolidated Balance Sheets.

(b) BHC has guaranteed the full and complete payment and performance on behalf of Black Hills Electric Generation for construction of Busch Ranch II. The guarantee terminates when BHC or Black Hills Electric Generation has paid for and performed all guaranteed obligations.

(21) DISCONTINUED OPERATIONS

Results of operations for discontinued operations were classified as Net (loss) from discontinued operations in the accompanying Consolidated Statements of Income. Prior periods relating to our discontinued operations were reclassified to reflect consistency within our consolidated financial statements.

Oil and Gas Segment

On November 1, 2017, the BHC Board of Directors approved a complete divestiture of our Oil and Gas segment. We completed the divestiture in 2018.

In 2017, we performed a fair value assessment of the assets and liabilities classified as held for sale. We evaluated our disposal groups classified as held for sale based on the lower of carrying value or fair value less cost to sell. The market approach was based on our fourth quarter 2017 sale of our Powder River Basin assets and pending sale transactions of our other properties. We believe that the estimates used in calculating the fair value of our assets and liabilities held for sale were reasonable based on the information that was known when the estimates were made. At December 31, 2017, the fair value of our held for sale assets was less than our carrying value, which required a pre-tax write down of $20 million. There were no adjustments made to the fair value of our held for sale liabilities.

For the year ended December 31, 2018, we recorded $3.3 million of expenses comprised of royalty payments and reclamation costs related to final closing on the sale of oil and gas assets.

Operating results of the Oil and Gas segment included in Discontinued operations on the accompanying Consolidated Statements of Income were as follows (in thousands):

	For the Years Ended	
	December 31, 2018	December 31, 2017
Revenue	$ 5,897	$ 25,382
Operations and maintenance	11,014	22,872
Loss on sale of assets	3,259	—
Depreciation, depletion and amortization	1,300	7,521
Impairment of long-lived assets	—	20,385
Total operating expenses	15,573	50,778
Operating (loss)	(9,676)	(25,396)
Interest income (expense), net	(19)	181
Other income (expense), net	190	(297)
Income tax benefit	2,618	8,413
Net (loss) from discontinued operations	$ (6,887)	$ (17,099)

(22) QUARTERLY HISTORICAL DATA (Unaudited)

The Company operates on a calendar year basis. The following tables set forth select unaudited historical operating results and market data for each quarter of 2019 and 2018.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2019				
Revenue	$ 597,810	$ 333,888	$ 325,548	$ 477,654
Operating income	$ 160,131	$ 54,001	$ 70,551	$ 121,359
Income from continuing operations	$ 107,362	$ 17,693	$ 15,395	$ 72,872
(Loss) from discontinued operations	$ —	$ —	$ —	$ —
Net income attributable to noncontrolling interest	$ (3,554)	$ (3,110)	$ (3,655)	$ (3,693)
Net income available for common stock	$ 103,808	$ 14,583	$ 11,740	$ 69,179
Amounts attributable to common shareholders:				
Net income from continuing operations	$ 103,808	$ 14,583	$ 11,740	$ 69,179
Net (loss) from discontinued operations	—	—	—	—
Net income available for common stock	$ 103,808	$ 14,583	$ 11,740	$ 69,179
Income per share for continuing operations - Basic	$ 1.73	$ 0.24	$ 0.19	$ 1.13
(Loss) per share for discontinued operations - Basic	—	—	—	—
Earnings per share - Basic	$ 1.73	$ 0.24	$ 0.19	$ 1.13
Income per share for continuing operations - Diluted	$ 1.73	$ 0.24	$ 0.19	$ 1.13
(Loss) per share for discontinued operations - Diluted	—	—	—	—
Earnings per share - Diluted	$ 1.73	$ 0.24	$ 0.19	$ 1.13

Included within the Income (loss) from continuing operations in the third quarter of 2019 is $15 million non-cash after-tax impairment of our investment in equity securities of a privately held oil and gas company.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2018				
Revenue	$ 575,389	$ 355,704	$ 321,979	$ 501,196
Operating income	$ 148,274	$ 69,551	$ 65,085	$ 114,127
Income from continuing operations	$ 138,977	$ 27,167	$ 21,801	$ 91,604
(Loss) from discontinued operations	$ (2,343)	$ (2,427)	$ (857)	$ (1,260)
Net income attributable to noncontrolling interest	$ (3,630)	$ (2,823)	$ (3,994)	$ (3,773)
Net income available for common stock	$ 133,004	$ 21,917	$ 16,950	$ 86,571
Amounts attributable to common shareholders:				
Net income from continuing operations	$ 135,347	$ 24,344	$ 17,807	$ 87,831
Net (loss) from discontinued operations	(2,343)	(2,427)	(857)	(1,260)
Net income available for common stock	$ 133,004	$ 21,917	$ 16,950	$ 86,571
Income per share for continuing operations - Basic	$ 2.54	$ 0.46	$ 0.33	$ 1.52
(Loss) per share for discontinued operations - Basic	(0.05)	(0.05)	(0.02)	(0.02)
Earnings per share - Basic	$ 2.49	$ 0.41	$ 0.32	$ 1.50
Income per share for continuing operations - Diluted	$ 2.50	$ 0.45	$ 0.32	$ 1.51
(Loss) per share for discontinued operations - Diluted	(0.04)	(0.05)	(0.02)	(0.02)
Earnings per share - Diluted	$ 2.46	$ 0.40	$ 0.31	$ 1.49

Included within the Income (loss) from continuing operations in the first and fourth quarters of 2018 are tax benefits of $49 million and $23 million, respectively, related to goodwill that is amortizable for tax purposes which resulted from legal entity restructuring.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 (Exchange Act)) as of December 31, 2019. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective.

Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Security Exchange Act of 1934, as amended, is recorded, processed, summarized and reported, within the time periods specified in the Commission's rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the quarter ended December 31, 2019, there were no changes in the Company's internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting is presented on Page 73 of this Annual Report on Form 10-K.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information required under this item with respect to directors and information required by Items 401, 405, 406, 407(c)(3), 407 (d)(4) and 407(d)(5) of Regulation S-K, is set forth in the Proxy Statement for our 2020 Annual Meeting of Shareholders, which is incorporated herein by reference. Information about our Executive Officers is reported in Part 1 of this Annual Report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

Information required under this item is set forth in the Proxy Statement for our 2020 Annual Meeting of Shareholders, which is incorporated herein by reference.

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

Information regarding the security ownership of certain beneficial owners and management is set forth in the Proxy Statement for our 2020 Annual Meeting of Shareholders, which is incorporated herein by reference.

EQUITY COMPENSATION PLAN INFORMATION

The following table includes information as of December 31, 2019 with respect to our equity compensation plans. These plans include the 2005 Omnibus Incentive Plan and 2015 Omnibus Incentive Plan.

Equity Compensation Plan Information

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders	160,179 (1)	$ 39.99 (1)	672,049 (2)
Equity compensation plans not approved by security holders	—	$ —	—
Total	160,179	$ 39.99	672,049

(1) Includes 146,179 full value awards outstanding as of December 31, 2019, comprised of restricted stock units, performance shares, short-term incentive plan (STIP) units and Director common stock units. The weighted average exercise price does not include the restricted stock units, performance shares, STIP or common stock units. In addition, 192,120 shares of unvested restricted stock were outstanding as of December 31, 2019, which are not included in the above table because they have already been issued.

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

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information regarding certain relationships and related transactions and director independence is set forth in the Proxy Statement for our 2020 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information regarding principal accounting fees and services is set forth in the Proxy Statement for our 2020 Annual Meeting to Shareholders, which is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) 1. Consolidated Financial Statements

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

2. Schedules

Schedule II — Consolidated Valuation and Qualifying Accounts for the years ended December 31, 2019, 2018 and 2017

3. Exhibits

All other schedules have been omitted because of the absence of the conditions under which they are required or because the required information is included in our consolidated financial statements and notes thereto.

SCHEDULE II

Consolidated valuation and qualifying accounts are detailed within Note 1 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

3. Exhibits

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

	Fourth Supplemental Indenture dated as of November 19, 2013 (filed as Exhibit 4 to the Registrant's Form 8-K filed on November 18, 2013).
	Fifth Supplemental Indenture dated as of January 13, 2016 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on January 13, 2016).
	Sixth Supplemental Indenture dated as of August 19, 2016 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on August 19, 2016).
	Seventh Supplemental Indenture dated as of August 17, 2018 (filed as Exhibit 4.2 to the Registrant's Form 8-K filed on August 17, 2018).
	Eighth Supplemental Indenture dated as of October 3, 2019 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on October 4, 2019).
4.2*	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as Exhibit 4.19 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)).
	First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)).
	Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant's Post-Effective Amendment No. 2 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)).
	Third Supplemental Indenture, dated as of October 1, 2014, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on October 2, 2014).
4.3*	Restated Indenture of Mortgage, Deed of Trust, Security Agreement and Financing Statement, amended and restated as of November 20, 2007, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on October 2, 2014).
	First Supplemental Indenture, dated as of September 3, 2009, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on October 2, 2014).
	Second Supplemental Indenture, dated as of October 1, 2014, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.4 to the Registrant's Form 8-K filed on October 2, 2014).
4.4*	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000).
4.5	Description of Securities
10.1*†	Amended and Restated Pension Equalization Plan of Black Hills Corporation dated November 6, 2001 (filed as Exhibit 10.11 to the Registrant's Form 10-K/A for 2001).
	First Amendment to Pension Equalization Plan (filed as Exhibit 10.10 to the Registrant's Form 10-K for 2002).
	Grandfather Amendment to the Amended and Restated Pension Equalization Plan of Black Hills Corporation (filed as Exhibit 10.2 to the Registrant's Form 10-K for 2008).
10.2*†	2005 Pension Equalization Plan of Black Hills Corporation (filed as Exhibit 10.3 to the Registrant's Form 10-K for 2008).
10.3*†	Restoration Plan of Black Hills Corporation (filed as Exhibit 10.5 to the Registrant's Form 10-K for 2008).
	First Amendment to the Restoration Plan of Black Hills Corporation dated July 24, 2011 (filed as Exhibit 10.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2011).
10.4*†	Black Hills Corporation Non-qualified Deferred Compensation Plan as Amended and Restated effective January 1, 2011 (filed as Exhibit 10.4 to the Registrant's Form 10-K for 2010).
10.5*†	First Amendment to the Black Hills Corporation Nonqualified Deferred Compensation Plan as Amended and Restated effective January 1, 2011 (filed as Exhibit 10.5 to the Registrant's Form 10-K for 2018).
10.6*†	Black Hills Corporation Post-2018 Nonqualified Deferred Compensation Plan (filed as Exhibit 10.6 to the Registrant's Form 10-K for 2018).

10.7*†	Black Hills Corporation 2005 Omnibus Incentive Plan ("Omnibus Plan") (filed as Appendix A to the Registrant's Proxy Statement filed April 13, 2005). First Amendment to the Omnibus Plan (filed as Exhibit 10.11 to the Registrant's Form 10-K for 2008). Second Amendment to the Omnibus Plan (filed as Exhibit 10 to the Registrant's Form 8-K filed on May 26, 2010).
10.8*†	Black Hills Corporation 2015 Omnibus Incentive Plan (filed as Appendix B to the Registrant's Proxy Statement filed March 19, 2015).
10.9*†	Form of Stock Option Agreement for Omnibus Plan effective for awards granted on or after January 1, 2014 (filed as Exhibit 10.7 to the Registrant's Form 10-K for 2013). Form of Stock Option Agreement effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.8 to Registrant's Form 10-K for 2015).
10.10*†	Form of Restricted Stock Award Agreement effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.10 to Registrant's Form 10-K for 2015).
10.11*†	Form of Restricted Stock Unit Award Agreement for 2015 Omnibus Plan effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.12 to the Registrant's Form 10-K for 2015).
10.12†	Form of Performance Share Award Agreement effective for awards granted on or after January 1, 2016 (filed as Exhibit 10.6 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2016). Form of Performance Share Award Agreement effective for awards granted on or after January 1, 2017.
10.13*†	Form of Short-term Incentive effective for awards granted on or after January 1, 2016 (filed as Exhibit 10.7 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2016).
10.14*†	Form of Indemnification Agreement (filed as Exhibit 10.5 to the Registrant's Form 8-K filed on September 3, 2004).
10.15†	Change in Control Agreement dated November 15, 2019 between Black Hills Corporation and Linden R. Evans.
10.16†	Change in Control Agreements between Black Hills Corporation and its non-CEO Senior Executive Officers.
10.17*†	Outside Directors Stock Based Compensation Plan as Amended and Restated effective January 1, 2009 (filed as Exhibit 10.23 to the Registrant's Form 10-K for 2008). First Amendment to the Outside Directors Stock Based Compensation Plan effective January 1, 2011 (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2010). Second Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2013 (filed as Exhibit 10.15 to the Registrant's Form 10-K for 2012). Third Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2015 (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2014). Fourth Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2017 (filed as Exhibit 10.4 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2016). Fifth Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2018 (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2017).
10.18*†	Sixth Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2019 (filed as Exhibit 10.18 to the Registrant's Form 10-K for 2018).
10.19*†	Form of Non-Disclosure and Non-Solicitation Agreement for Certain Employees (filed as Exhibit 10.8 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2016).
10.20	Equity Distribution Sales Agreement dated August 4, 2017 among Black Hills Corporation and the several Agents named therein (filed as Exhibit 1.1 to the Registrant's Form 8-K filed on August 4, 2017). First Amendment to the Equity Distribution Sales Agreement.
10.21*	Third Amended and Restated Credit Agreement dated as of July 30, 2018 (relating to $750 million Revolving Credit Facility), among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and U.S. Bank, National Association, as Administrative Agent (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on July 31, 2018).

10.22*	Amended and Restated Credit Agreement dated as of July 30, 2018 (relating to $300 million, two-year term loan), among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on July 31, 2018). First Amendment dated as of June 17, 2019 to Amended and Restated Credit Agreement dated as of July 30, 2018, among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Registrant's Form 8–K filed on June 17, 2019).
10.23*	Coal Leases between WRDC and the Federal Government -Dated May 1, 1959 (filed as Exhibit 5(i) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(h) to the Registrant's Form 10-K for 1989) -Dated April 1, 1961 (filed as Exhibit 5(j) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(i) to Registrant's Form 10-K for 1989) -Dated October 1, 1965 (filed as Exhibit 5(k) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(j) to the Registrant's Form 10-K for 1989).
10.24*	Assignment of Mining Leases and Related Agreement effective May 27, 1997, between WRDC and Kerr-McGee Coal Corporation (filed as Exhibit 10(u) to the Registrant's Form 10-K for 1997).
21	List of Subsidiaries of Black Hills Corporation.
23.1	Consent of Independent Registered Public Accounting Firm.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95	Mine Safety and Health Administration Safety Data
101.INS	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
104	Cover Page Interactive Data File (formatted as inline XBRL and contained in Exhibit 101)

* Previously filed as part of the filing indicated and incorporated by reference herein.
† Indicates a board of director or management compensatory plan.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

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

BLACK HILLS CORPORATION

By: /S/ LINDEN R. EVANS
Linden R. Evans, President and Chief Executive Officer

Dated: February 14, 2020

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

/S/ LINDEN R. EVANS Linden R. Evans, President and Chief Executive Officer	Director and Principal Executive Officer	February 14, 2020
/S/ RICHARD W. KINZLEY Richard W. Kinzley, Senior Vice President and Chief Financial Officer	Principal Financial and Accounting Officer	February 14, 2020
/S/ DAVID R. EMERY David R. Emery, Executive Chairman	Director and Executive Chairman	February 14, 2020
/S/ TONY A. JENSEN Tony A. Jensen	Director	February 14, 2020
/S/ MICHAEL H. MADISON Michael H. Madison	Director	February 14, 2020
/S/ KATHLEEN S. MCALLISTER Kathleen S. McAllister	Director	February 14, 2020
/S/ STEVEN R. MILLS Steven R. Mills	Director	February 14, 2020
/S/ ROBERT P. OTTO Robert P. Otto	Director	February 14, 2020
/S/ REBECCA B. ROBERTS Rebecca B. Roberts	Director	February 14, 2020
/S/ MARK A. SCHOBER Mark A. Schober	Director	February 14, 2020
/S/ TERESA A. TAYLOR Teresa A. Taylor	Director	February 14, 2020
/S/ JOHN B. VERING John B. Vering	Director	February 14, 2020
/S/ THOMAS J. ZELLER Thomas J. Zeller	Director	February 14, 2020

Use of Non-GAAP Financial Measures

Earnings Per Share, as adjusted (Non-GAAP Measure)	Year Ended Dec. 31 2019	2018	2017	2016	2015	2014
Income from continuing operations available for common stock (GAAP)	**$ 3.28**	**$ 4.78**	**$ 3.52**	**$ 2.57**	**$ 3.12**	**$ 2.97**
Adjustments (loss) (*pre-tax*):						
Impairment of investment	0.32	-	-	-	-	-
Integration expenses	-	-	0.08	0.86	0.23	-
Tax reform and other tax items	-	0.07	(0.21)	-	-	-
Legal restructuring - income tax benefit	-	(1.31)	-	-	-	-
Total Adjustments	0.32	(1.24)	(0.13)	0.86	0.23	-
Taxes on Adjustments:						
Impairment of investment	(0.07)	-	-	-	-	-
Acquisition costs	-	-	(0.03)	(0.30)	(0.08)	-
Total tax on adjustments	(0.07)	-	(0.03)	(0.30)	(0.08)	-
Earnings Per Share from continuing operations available for common stock, as adjusted (Non-GAAP)	**$ 3.53**	**$ 3.54**	**$ 3.36**	**$ 3.13**	**$ 3.27**	**$ 2.97**

* 3.5 percent compound annual growth rate in earnings per share from continuing operations available for common stock, as adjusted, from 2014 to 2019

EBITDA, as adjusted (Non-GAAP Measure, in millions)	Year Ended Dec. 31 2019	2018	2017	2016	2015	2014
Income from continuing operations (GAAP)	**$ 213.3**	**$ 279.5**	**$ 208.4**	**$ 146.8**	**$ 141.5**	**$ 132.5**
Depreciation, depletion and amortization	209.1	196.3	188.2	175.5	126.5	121.0
Interest expense, net	137.7	140.0	137.1	134.7	83.0	69.9
Income tax expense	29.6	(23.7)	73.4	59.1	78.7	67.3
Rounding	-	0.1	(0.1)	-	0.1	(0.1)
EBITDA (Non-GAAP Measure)	**589.7**	**592.2**	**607.0**	**516.1**	**429.8**	**390.6**
Less: Adjustments for unique items						
Impairmet of investment	**19.7**	**-**	**-**	**-**	**-**	**-**
Acquisition costs	-	-	4.4	43.7	3.6	-
EBITDA, as adjusted (Non-GAAP Measure)	**$ 609.4**	**$ 592.2**	**$ 611.4**	**$ 559.8**	**$ 433.4**	**$ 390.6**

* 9.3 percent compound annual growth rate in EBITDA, as adjusted, from 2014 to 2019

NON-GAAP

Earnings per share, as adjusted

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

EBITDA and EBITDA, as adjusted

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

Limitations on the Use of Non-GAAP Measures

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

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

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BOARD OF DIRECTORS

Pictured in the back row (from left): David R. Emery, Kathleen S. McAllister, Thomas J. Zeller, Linden R. Evans, Steven R. Mills, John B. Vering, Mark A. Schober, Michael H. Madison. Seated (from left): Tony A. Jensen, Rebecca B. Roberts, Robert P. Otto, Teresa A. Taylor.

We welcomed Tony Jensen and Kathleen McAllister to our board in 2019 and will say goodbye to two long-time contributors — David Emery and Tom Zeller — who are retiring from the Black Hills Corp. board.

We wish to express our appreciation to Tom Zeller, who will retire from the board on April 28, 2020, after 23 years of service. With his extensive experience, Tom has provided leadership, wisdom and guidance to the board during a period of profound transformation for our company and our industry.

Our Executive Chairman of the Board, David Emery, will retire on May 1, 2020, after 30 years of service to Black Hills Corp., including 16 years on the board and 15 years as CEO. Through his leadership and vision, David has made a lasting contribution to our company, our employees, and to those we proudly serve.

Thank you, Tom and David, for your service and commitment to our company.

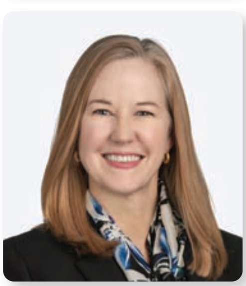
BOARD OF DIRECTORS

David R. Emery, age 57, was elected to the Board in 2004. He has been Executive Chairman since January 1, 2019, was our Chairman and CEO from 2016 through 2018, and Chairman, President and CEO from 2005 through 2015. Prior to that he held various positions with the Company, including President and CEO from 2004 to 2005, President and COO - Retail Business Segment from 2003 to 2004, and Vice President of Fuel Resources from 1997 to 2003.

Linden R. Evans, age 57, was elected to the Board in November 2018. He has been President and CEO since January 1, 2019, President and COO from 2016 through 2018, and President and COO — Utilities from 2004 through 2015. Prior to that he served as the Vice President and General Manager of our former communication subsidiary in 2003 and 2004, and Associate Counsel from 2001 to 2003.

Tony A. Jensen, age 58, was elected to the Board on November 1, 2019. He was President and CEO and Director of Royal Gold, Inc., a public precious metals company, from 2006 to 2019, and COO from 2003 to 2006.

Michael H. Madison, age 71, was elected to the Board in 2012 and chairs the Compensation Committee. He was President and CEO and Director of Cleco Corporation, a public utility holding company, from 2005 to 2011, President and COO of Cleco Power, LLC from 2003 to 2005, and State President, Louisiana-Arkansas with American Electric Power from 2000 to 2003.



Kathleen S. McAllister, age 55, was elected to the Board on November 1, 2019. She was President and CEO and Director of Transocean Partners LLC, a growth-oriented public company and subsidiary of Transocean Ltd., an international provider of offshore contract drilling services for oil and gas wells, from 2014 to 2016, and Chief Financial Officer in 2016. She also serves on the Boards of Hoegh LNG Partners LP and Maersk Drilling.

Steven R. Mills, age 64, was elected to the Board in 2011 and is our Lead Director. He is a Consultant and Advisor to Naxos Capital Partners, a European-based private equity company. He previously served as CFO of Amyris, Inc., a renewable products company, from 2012 to 2013. He also served as Senior Executive Vice President Performance and Growth and CFO at Archer Daniels Midland Co., one of the world's largest agricultural processors and food ingredient providers, from 2010 to 2012. He also serves on the Board of Amyris, Inc.

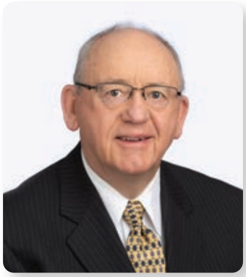
Robert P. Otto, age 60, was elected to the Board in 2017. He has been the owner of Bob Otto Consulting LLC, providing strategic planning and services in cyber security, intelligence and reconnaissance since 2017. He retired from the U.S. Air Force in 2016 as a lieutenant general. He served as a general officer since 2008, culminating as the Air Force Deputy Chief of Staff for Intelligence, Surveillance and Reconnaissance.

Rebecca B. Roberts, age 67, was elected to the Board in 2011 and chairs the Governance Committee. She was President of Chevron Pipe Line Company, a pipeline company transporting crude oil, refined petroleum products, liquefied petroleum gas, natural gas and chemicals within the U.S., from 2006 to 2011, and President of Chevron Global Power Generation from 2003 to 2006. She also serves on the Boards of AbbVie, Inc. and MSA Safety, Inc.

Mark A. Schober, age 64, was elected to the Board in 2015 and chairs the Audit Committee. He was Senior Vice President and CFO of ALLETE, Inc., a public utility company, from 2006 to 2014. He previously held several positions in accounting and finance.

Teresa A. Taylor, age 56, was elected to the Board in 2016. She has been CEO of Blue Valley Advisors, LLC since 2011. She previously served as COO of Qwest Communications, Inc., a telecommunications carrier, from 2009 to 2011. She also served in other leadership roles at Qwest and the former U.S. West beginning in 1987, including Executive Vice President and Chief Administrative Officer. She also serves on the Boards of T-Mobile USA, Inc. and First Interstate BancSystem, Inc.

John B. Vering, age 70, was elected to the Board in 2005. He was Managing Director of Lone Mountain Investments, Inc., an oil and gas investment firm, from 2002 to 2019. He previously held several executive positions in the oil and gas industry.



Thomas J. Zeller, age 72, was elected to the Board in 1997. He was CEO of RESPEC, a technical consulting and services firm with expertise in engineering, information technologies and water and natural resources, specializing in emerging environmental protection protocols, in 2011, and served as President from 1995 to 2011.

EXECUTIVE OFFICERS

David R. Emery, age 57, has been Executive Chairman since January 1, 2019, Chairman and Chief Executive Officer from 2016 through 2018, and Chairman, President and Chief Executive Officer from 2005 through 2015. Prior to that, he held various positions with the Company, including President and Chief Executive Officer and member of the Board of Directors from 2004 to 2005, President and Chief Operating Officer — Retail Business Segment from 2003 to 2004 and Vice President - Fuel Resources from 1997 to 2003. Mr. Emery has 30 years of experience with the Company.

Linden R. Evans, age 57, 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 18 years of experience with the Company.

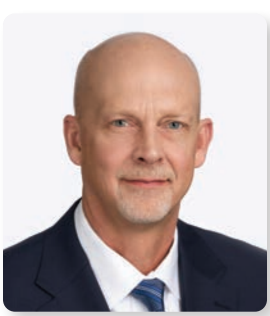
Karen Beachy, age 48, has been our Senior Vice President — Growth and Strategy since August 26, 2019. She served as Vice President — Growth and Strategy from 2018 to August 2019, Vice President — Supply Chain from 2016 to 2018, and Director of Supply Chain from 2014 to 2016. Ms. Beachy has five years of experience with the Company.

Scott A. Buchholz, age 58, has been our Senior Vice President — Chief Information Officer since the closing of the Aquila Transaction in 2008. Prior to joining the Company, he was Aquila's Vice President of Information Technology from 2005 until 2008, Six Sigma Deployment Leader/Black Belt from 2004 until 2005, and General Manager, Corporate Information Technology from 2002 until 2004. Mr. Buchholz has 39 years of experience with the Company, including 28 years with Aquila.

Brian G. Iverson, age 57, 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 16 years of experience with the Company.

Richard W. Kinzley, age 54, 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 20 years of experience with the Company.

Jennifer C. Landis, age 45, 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 18 years of experience with the Company.



Stuart Wevik, age 58, has been our Senior Vice President — Utility Operations since August 26, 2019. He served as Group Vice President — Electric Utilities from 2016 to August 2019, Vice President — Utility Operations from 2008 to 2016, Vice President — Operations from 2004 to 2008, and Vice President and General Manager from 2003 to 2004. Mr. Wevik has 34 years of experience with the Company.

EXECUTIVE OFFICERS

Pictured in the back row (from left): Jennifer Landis, Linn Evans, Stuart Wevik, Karen Beachy, Brian Iverson

Seated (from left): Scott Buchholz, Rich Kinzley

INVESTOR INFORMATION

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

Senior Unsecured Notes — Black Hills Corporation
Wells Fargo Bank, N.A.
Corporate Trust Services
MAC N9300-070
600 S. 4th Street, 6th Floor
Minneapolis, MN 55415

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

First Mortgage Bonds — Cheyenne Light, Fuel & Power
Wells Fargo Bank, N.A.
Corporate Trust Services
MAC N9300-070
600 S. 4th Street, 6th Floor
Minneapolis, MN 55415

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

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

Corporate Offices
Black Hills Corporation
P.O. Box 1400
7001 Mount Rushmore Road
Rapid City, SD 57702
605-721-1700
www.blackhillscorp.com

2020 Annual Meeting
The Annual Meeting of Shareholders will be held at Horizon Point, the Company's corporate headquarters at 7001 Mount Rushmore Road, Rapid City, South Dakota, at 9:30 a.m. local time on Tuesday, April 28, 2020. Prior to the meeting, formal notice, proxy statement and proxy will be mailed to shareholders.

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

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

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

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

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

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

We take a programmatic approach to maintaining, upgrading and replacing critical infrastructure to better serve our customers. On the cover, Jerome and Linda monitor the construction of the Natural Bridge pipeline project in Central Wyoming.

List of BH Nebraska Gas Witnesses and subjects on which they are to provide testimony

241 Neb. Admin. Code. Ch. 9., Rule 004.02G.

Black Hills Nebraska Gas presents eleven (11) witnesses in support of its Application.

WITNESS	PURPOSE OF TESTIMONY
Robert J. Amdor Director, Regulatory & Finance	Application Overview, Case Drivers, Witness Introduction, Company Policy, Prior Proceeding Commitments, Employee Compensation, Cost of Capital. Interim Rates. and Covid-19 Pandemic
Jason L. Bennett Manager, Regulatory & Finance	Filing Requirements, Accounting. & Capital Spend, Contributions, Dues, and Lobbying, Farm Tap Replacement Program, SSIR Modifications, 2021 SSIR, ALLO Surcharge, Consolidation synergies, and Rate Review Expenses
Michael C. Clevinger Senior Manager, Regulatory & Finance	Revenue Requirement Study, CAMS, and Adjustments
Tyler E. Frost Manager, Regulatory & Finance	High Efficiency Appliance Tool, Low Income Customer Support, Changes in Fees, and Tariff Sheets
Douglas N. Hyatt Principal Analyst, Regulatory & Finance	Rate Design & Billing Determinants
Kevin M. Jarosz Vice President Nebraska Operations	Operations, Customer Service, Capital Spend, and Capital Infrastructure Investment Projects
Justin W. Klapperich Finance Director III, Tax	ADIT and Taxes
Mark I. Lewis Director, Gas Pipeline and System Integrity	Safety Investment & Risk Ranking
Adrien M. McKenzie FinCap	Return on Equity and Capital Structure
Dr. David Rosenbaum Rosenbaum Consulting	Customer Growth & HEAT Program
Thomas J. Sullivan Navillus Consulting	Class Cost of Service and Rate Design

1. **<u>Mr. Robert Amdor, Director of Regulatory and Finance</u>**

Mr. Amdor presents an overview of the rate review application. His testimony discusses and provides (a) the primary drivers for this rate review application, (b) a summary of other Company witnesses, (c) a discussion of commitments made by the Company in prior Commission proceedings leading up to this rate review, (d) a description of and support for various company and corporate policies involved in this rate review, (e) support of employee and executive compensation, (f) support for the Company's proposed pro forma capital structure of 50% debt and 50% equity and return on equity of 9.9%, (g) clarification that BH Nebraska Gas will implement interim rates, subject to refund, commencing on August 1, 2020, and (h) support for a number of different items included within this rate review.

2. **<u>Mr. Jason L. Bennett, Manager - Regulatory and Finance</u>**

Mr. Bennett addresses Rate Review Application filing requirements, Company accounting methods, contributions, dues, lobbying, Capital Infrastructure Project Investment, Capital Additions, the Farm Tap Replacement Program, System Safety and Integrity Rider (SSIR) modifications, ALLO Regulatory Accounting Order Surcharge mechanism, Consolidation Synergies, Rate Review Expenses, and Gas Storage Inventory.

3. **<u>Mr. Michael C. Clevinger, Sr. Manager – Regulatory and Finance</u>**

Mr. Clevinger sponsors the Revenue Requirement Study and explains the requested revenue increase by describing the Test Year, rate base, revenues, and operating expenses, with known and measurable and certain other adjustments, to reflect the revenue needed to recover the costs to provide service to the BH Nebraska Gas customers and for the Company to have the opportunity to earn a fair return. He presents the results of a depreciation study used in the Revenue Requirement Study and sponsors the Cash Working Capital calculation and Lead-Lag Study. Mr. Clevinger discusses changes to the Cost Allocation Manual resulting from the consolidation of BH Gas Utility and BH Gas Distribution, and corporate changes, including the allocation impacts related to consolidation of support services now provided by BHSC. Mr. Clevinger supports adjustments related to facilities, merit increases, IT Cyber Security Improvements, employee additions, and others. Finally, Mr. Clevinger addresses Affiliate Transactions.

4. **<u>Mr. Tyler E. Frost, Manager - Regulatory and Finance</u>**

Mr. Frost supports the proposed tariff changes, explains the HEAT program proposal and competitive threats. Mr. Frost also offers the customer bill comparisons between customers' existing rates as of the day of filing this Rate Review and customers' bills on March 1, 2021, when new rates resulting from this proceeding are anticipated to become effective.

5. **<u>Mr. Douglas N. Hyatt, Principal Regulatory Analyst – Regulatory & Finance</u>**

Mr. Hyatt discusses the billing determinants used in the Class Cost of Service Study, presents adjustments to the billing determinants, discusses the weather normalization adjustment, and provides Test Year billing determinants sponsors the customer class load factor analysis, and sponsors the revenue proofs.

6. **Mr. Kevin M. Jarosz, Vice President - Operations**

Mr. Jarosz provides a general overview of the Company's Nebraska gas system and service territory, staffing, customer service, community involvement and performance. He also discusses the Company's existing practices to maintain the safety and integrity of the Nebraska pipeline system and describes the specific projects BH Nebraska Gas is proposing to include in the SSIR mechanism. He also supports the proposed SSIR as the appropriate recovery mechanism for the significant investment programs. Mr. Jarosz also discusses the capital additions between January 1, 2020 and December 31, 2020.

7. **Mr. Justin W. Klapperich, Director - Tax**

Mr. Klapperich supports the calculation of income tax expense and related Accumulated Deferred Income Taxes ("ADIT") in the Revenue Requirement Study. He also discusses the tax impacts of the Tax Cuts and Jobs Act of 2017 on the requested revenue requirement, including the accounting for excess deferred income taxes ("EDIT") in compliance with Application No. NG-0095-PI-213, NG-0095.2, NG-0095.3. Mr. Klapperich supports a Transition Report (a/k/a "Synergy Savings Report") required under Commission Application No. NG–0084 (SourceGas Acquisition).

8. **Mr. Marc I. Lewis, Director - Gas Pipeline and System Integrity**

Mr. Lewis describes the programmatic capital investment and risk ranking of Capital Infrastructure Projects developed for BH Nebraska Gas. Mr. Lewis describes the federal and state regulations governing pipeline safety and the Company's specific system safety and integrity projects. Mr. Lewis discusses the Company's approach to assessing and prioritizing efforts to improve the overall safety of the gas distribution system. Mr. Lewis supports the Data Integrity Improvement Program and explains how investing in data systems will benefit customers in the future.

9. **Mr. Adrien M. McKenzie, President - Financial Concepts and Applications**

Mr. McKenzie supports the proposed cost of common equity used in the capital structure to determine the weighted average cost of capital incorporated in the Revenue Requirement Study. Mr. McKenzie discusses current capital markets and provides an expert assessment of the range of reasonable rates of return on equity for BH Nebraska Gas of 9.4% to 10.7%. Mr. McKenzie's testimony supports a 10% return on equity requested by BH Nebraska Gas.

10. **Dr. David Rosenbaum - Rosenbaum Economic Consulting**

Dr. Rosenbaum presents analyses performed to verify the cost effectiveness of the Company's High Efficiency Appliance Tool ("HEAT") program rebates to address the challenges related to rural decline and competition from publicly owned electric utilities.

Dr. Rosenbaum provides research confirming that most new appliance installations within the BH Nebraska Service Rate Areas are electric, and except for the most recent years, Rate Areas

Three (former BH Gas Utility) and Five (former BH Gas Distribution) experienced a decline in population and customer count.

This research proves the necessity of continuing the existing appliance incentive program, but also supports expanding the HEAT Program throughout all BH Nebraska Rate Areas.

11. **Mr. Thomas J. Sullivan, President - Navillus Utility Consulting LLC**

Mr. Sullivan sponsors the Class Cost of Service Study and Rate Design model, provides a historical review of rural decline and competitive threats, and discusses the perspective development of the proposed customer classes, the combination of the classes resulting from the consolidation of the two gas utilities, the Company's approach to mitigating the rate impacts of consolidating customer classes, and the development of the proposed customer rates for all customer classes. He also provides historical perspective of the competitive threats to the system and recommends several tools to offset these challenges. Mr. Sullivan provides an alternative Straight-Fixed Variable rate design in the event the Commission does not prefer the block rate designed recommended by BH Nebraska Gas.