THIS FILING IS

Item 1: [X] An Initial (Original) Submission OR [ ] Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2022)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2022)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Black Hills Power, Inc.	End of 2020/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: https://forms.ferc.gov/. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ___________ , we have also reviewed schedules ___________________of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/overview.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/media/form-1 and https://www.ferc.gov/media/form1-3q.

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18^{th} of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and” firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1/3-Q: REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Black Hills Power, Inc.	02 Year/Period of Report End of 2020/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 7001 Mount Rushmore Road, Rapid City, SD 57702	
05 Name of Contact Person Marne Jones	06 Title of Contact Person VP - Regulatory & Finance
07 Address of Contact Person *(Street, City, State, Zip Code)* 7001 Mount Rushmore Road, Rapid City, SD 57702	

08 Telephone of Contact Person, *Including Area Code* (605) 721-2348	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 04/16/2021

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Marne Jones 02 Title VP - Regulatory & Finance	03 Signature Marne Jones	04 Date Signed *(Mo, Da, Yr)* 04/16/2021

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	NA
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	NA
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	NA
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	NA
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	NA
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	NA
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	NA
65	Pumped Storage Generating Plant Statistics	408-409	NA
66	Generating Plant Statistics Pages	410-411	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [X] Two copies will be submitted [ ] No annual report to stockholders is prepared		

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Richard W. Kinzley
Sr. Vice President and Chief FInancial Officer
7001 Mt. Rushmore Rd
Rapid City, SD 57702

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

South Dakota - August 27, 1941

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

NA

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric Service - South Dakota, Wyoming and Montana

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

Black Hills Power, Inc. is a wholley-owned subsidiary of Black Hills Corporation and at December 31, 2020 Black Hills Corporation owned 100% of the common stock of Black Hills Power, Inc.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	None			
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	President & Chief Executive Officer	Linden R. Evans	790,000
2	Sr. Vice President and Chief Financial Officer	Richard W. Kinzley	454,000
3	Sr. Vice President and General Counsel	Brian G. Iverson	386,000
4	Sr. Vice President - Chief Human Resources Officer	Jennifer C. Landis	286,000
5	Sr. Vice President - Utility Operations	Stuart A. Wevik	407,000
6	Sr. Vice President - Growth and Strategy	Karen H. Beachy	301,000
7	Sr. Vice President - Chief Information Officer	Scott A. Buchholz	340,000
8	Sr. Vice President - Chief Information Officer	Erik D. Keller	127,000
9	Vice President - BHE South Dakota	Marc Eyre	170,000
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Name of Respondent Black Hills Power, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report 2020/Q4

FOOTNOTE DATA

Schedule Page: 104   Line No.: 6   Column: c

Salary shown is an annual amount and has not been prorated for the partial year each person was in their respective position.

01-01-2020 to 12-04-2020

Schedule Page: 104   Line No.: 7   Column: c

Salary shown is an annual amount and has not been prorated for the partial year each person was in their respective position.

01-01-2020 to 10-26-2020

Schedule Page: 104   Line No.: 8   Column: c

Salary shown is an annual amount and has not been prorated for the partial year each person was in their respective position.

Appointed 10-26-2020

Schedule Page: 104   Line No.: 9   Column: c

Salary shown is an annual amount and has not been prorated for the partial year each person was in their respective position.

Appointed 03-31-2020

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Linden R. Evans (President and CEO)	Black Hills Corporation
2		7001 Mt. Rushmore Rd.
3		Rapid City, SD 57702
4		
5	Richard W. Kinzley (Sr. Vice President and CFO)	Black Hills Corporation
6		7001 Mt. Rushmore Rd.
7		Rapid City, SD 57702
8		
9	Brian G. Iverson (Sr. Vice President and General Counsel)	Black Hills Corporation
10		7001 Mt. Rushmore Rd.
11		Rapid City, SD 57702
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?

[X] Yes
[ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	BHP JOATT, Attachment H	ER18-1583-000
2	BHP JOATT, Schedule 2	ER15-2366-000
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[ ] Yes
[X] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
1	207	Electric Plant in Service	g	99
2	219	Accumulated Provision for Depreciation	c	28
3	219	Accumulated Provision for Depreciation	c	25
4	219	Accumulated Provision for Depreciation	c	28
5	275	Accumulated Deferred Income Taxes	k	9
6	336	Depreciation and Amortization of Electric Plant	b	7
7	336	Depreciation and Amortization of Electric Plant	b	10
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) __ A Resubmission	04/16/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 1062 Line No.: 1 Column: d

The FF1 includes revenues for a corporate shared facility. The revenues associated with that facility are not reflected in the formula rate. Therefore, the Company removes the Gross Plant and Accumulated reserve associated with that facility from its formula rates.

Schedule Page: 1062 Line No.: 2 Column: d

Book Depreciation rates reported on the FF1 are those approved by the State Commission and Differ from Depreciation rates approved for the FERC Transmission Formula Rates. The FERC Formula Rates reflect the Accumulated Depreciation and Depreciation expense approved in the last FERC Formula rate review.

Schedule Page: 1062 Line No.: 3 Column: d

Book Depreciation rates reported on the FF1 are those approved by the State Commission and Differ from Depreciation rates approved for the FERC Transmission Formula Rates. The FERC Formula Rates reflect the Accumulated Depreciation and Depreciation expense approved in the last FERC Formula rate review.

Schedule Page: 1062 Line No.: 4 Column: d

The FF1 includes revenues for a corporate shared facility. The revenues associated with that facility are not reflected in the formula rate. Therefore, the Company removes the Gross Plant and Accumulated reserve associated with that facility from its formula rates.

Schedule Page: 1062 Line No.: 5 Column: d

The Company began allocation of ADIT from its service company to BHP in 2019. The ending balance on the FF1 now additionally contains allocated deferred income tax liabilities from Black Hills Service Company.

Schedule Page: 1062 Line No.: 6 Column: d

The Formula rate calculates the Depreciation expense in the formula rate by multiplying the Gross plant by the composite depreciation rates as approved by FERC.

Schedule Page: 1062 Line No.: 7 Column: d

The Formula rate calculates the Depreciation expense in the formula rate by multiplying the Gross plant by the composite depreciation rates as approved by FERC.

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) __ A Resubmission	04/16/2021	2020/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

1. None
2. None
3. None
4. None
5. None
6. None
7. None
8. The average BHP union increase for 2020 was 3%, the average non-union wage increase was 2.71%
9. None
10. None
11. None
12. None
13. The following Director and Officer changes occured during the year:

a. Marc Eyre was appointed Vice President - BHE South Dakota on March 31, 2020.

b. Mark L. Lux's title changed from Vice President - Electric Asset Optimization to Vice President -Asset Optimization effective September 21, 2020.

c. Wes Ashton was appointed Vice president - Customer Experience effective September 21, 2020.

d. Scott A. Buchholz's title changed from Senior Vice President - Chief Information Officer to Senior Vice President - Strategic Initiatives effective October 26, 2020.

e. Erik D. keller was appointed Senior Vice President - Chief Information Officer effective October 26, 2020.

f. Karen H. Beachy, Senior Vice President - Growth and Strategy, retired effective December 4, 2020.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	1,569,575,577	1,471,173,258
3	Construction Work in Progress (107)	200-201	35,881,998	44,767,879
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		1,605,457,575	1,515,941,137
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	452,451,971	464,170,180
6	Net Utility Plant (Enter Total of line 4 less 5)		1,153,005,604	1,051,770,957
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		1,153,005,604	1,051,770,957
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		0	0
19	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		681,808	514,516
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		4,657,249	4,564,854
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		5,339,057	5,079,370
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		0	1,000
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		4,966	4,966
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		14,636,630	14,675,892
41	Other Accounts Receivable (143)		1,758,734	167,870
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		255,787	159,646
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		19,150,663	13,037,992
45	Fuel Stock (151)	227	1,041,059	2,150,484
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	27,059,500	23,867,961
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	2,237,242	1,778,004
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		3,140,099	3,160,241
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		11,337,700	10,913,572
62	Miscellaneous Current and Accrued Assets (174)		918,744	153,618
63	Derivative Instrument Assets (175)		1,064,770	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		82,094,320	69,751,954
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		2,383,184	2,597,173
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	71,898,812	74,609,205
73	Prelim. Survey and Investigation Charges (Electric) (183)		295,767	124,309
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		1,357,240	1,722,763
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	4,720,808	4,191,046
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		719,004	988,792
82	Accumulated Deferred Income Taxes (190)	234	37,982,694	34,673,387
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		119,357,509	118,906,675
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		1,359,796,490	1,245,508,956

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	23,416,396	23,416,396
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		42,076,811	42,076,811
7	Other Paid-In Capital (208-211)	253	0	0
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	2,501,882	2,501,882
11	Retained Earnings (215, 215.1, 216)	118-119	412,342,957	389,425,722
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-1,420,318	-1,380,245
16	Total Proprietary Capital (lines 2 through 15)		473,913,964	451,036,802
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	340,000,000	340,000,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	0	2,855,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		77,970	82,110
24	Total Long-Term Debt (lines 18 through 23)		339,922,030	342,772,890
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		13,802,349	14,105,034
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		414,905	492,392
29	Accumulated Provision for Pensions and Benefits (228.3)		12,615,935	14,635,914
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		143,949	3,162,087
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		759,964	0
35	Total Other Noncurrent Liabilities (lines 26 through 34)		27,737,102	32,395,427
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		20,576,090	19,817,584
39	Notes Payable to Associated Companies (233)		170,996,488	82,867,465
40	Accounts Payable to Associated Companies (234)		40,159,833	32,120,834
41	Customer Deposits (235)		2,161,550	2,254,967
42	Taxes Accrued (236)	262-263	7,551,189	9,088,574
43	Interest Accrued (237)		4,654,225	4,652,426
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		1,058,414	1,070,019
48	Miscellaneous Current and Accrued Liabilities (242)		5,707,046	5,454,854
49	Obligations Under Capital Leases-Current (243)		316,852	293,388
50	Derivative Instrument Liabilities (244)		920,680	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		254,102,367	157,620,111
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		6,883,941	1,413,735
57	Accumulated Deferred Investment Tax Credits (255)	266-267	0	0
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	2,007,099	2,621,658
60	Other Regulatory Liabilities (254)	278	102,204,237	107,207,731
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		135,042,654	134,703,790
64	Accum. Deferred Income Taxes-Other (283)		17,983,096	15,736,812
65	Total Deferred Credits (lines 56 through 64)		264,121,027	261,683,726
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		1,359,796,490	1,245,508,956

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	303,367,621	302,510,728		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	141,693,409	144,035,989		
5	Maintenance Expenses (402)	320-323	22,087,069	23,031,869		
6	Depreciation Expense (403)	336-337	42,573,528	39,299,264		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	2,167			
8	Amort. & Depl. of Utility Plant (404-405)	336-337	1,774,436	1,985,481		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	97,406	97,406		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)					
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	10,880,795	9,230,621		
15	Income Taxes - Federal (409.1)	262-263	7,309,643	13,776,092		
16	- Other (409.1)	262-263		200		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	15,737,124	8,025,019		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	17,747,661	12,306,045		
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		1,686			
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		224,409,602	227,175,896		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		78,958,019	75,334,832		

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
303,367,621	302,510,728					2
						3
141,693,409	144,035,989					4
22,087,069	23,031,869					5
42,573,528	39,299,264					6
2,167						7
1,774,436	1,985,481					8
97,406	97,406					9
						10
						11
						12
						13
10,880,795	9,230,621					14
7,309,643	13,776,092					15
	200					16
15,737,124	8,025,019					17
17,747,661	12,306,045					18
						19
						20
						21
						22
						23
1,686						24
224,409,602	227,175,896					25
78,958,019	75,334,832					26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		78,958,019	75,334,832		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		714,514	488,925		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		762,811	688,350		
33	Revenues From Nonutility Operations (417)		2,859	39,499		
34	(Less) Expenses of Nonutility Operations (417.1)		163,112	84,598		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		1,154,659	1,693,995		
38	Allowance for Other Funds Used During Construction (419.1)		-10,492	-1,457		
39	Miscellaneous Nonoperating Income (421)		318,265	373,746		
40	Gain on Disposition of Property (421.1)		233,547	143,034		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		1,487,429	1,964,794		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		712,609	1,079,493		
46	Life Insurance (426.2)					
47	Penalties (426.3)		19	67		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		59,449	105,390		
49	Other Deductions (426.5)		490,858	5,844,862		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		1,262,935	7,029,812		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	29,449	17,194		
53	Income Taxes-Federal (409.2)	262-263	42,586	6,066		
54	Income Taxes-Other (409.2)	262-263				
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277				
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277				
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		72,035	23,260		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		152,459	-5,088,278		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		20,222,493	20,259,806		
63	Amort. of Debt Disc. and Expense (428)		282,461	204,975		
64	Amortization of Loss on Reaquired Debt (428.1)		269,788	269,788		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		5,698,766	3,800,554		
68	Other Interest Expense (431)		1,403	-9,923		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		1,301,343	1,436,770		
70	Net Interest Charges (Total of lines 62 thru 69)		25,173,568	23,088,430		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		53,936,910	47,158,124		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		53,936,910	47,158,124		

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		389,425,722	342,002,405
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7	Cumulative effect of ASU 2018-02 Reclassification of Certain Tax Effects from			270,907
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			270,907
10	Cumulative effect of ASU 2018-19, CECL adoption		-19,675	
11	Implementation of ASU 2016-02 Leases			(5,714)
12	Non-cash dividend to parent company			
13	Dividend to Parent		-31,000,000	
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		-31,019,675	(5,714)
16	Balance Transferred from Income (Account 433 less Account 418.1)		53,936,910	47,158,124
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31				
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		412,342,957	389,425,722
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		412,342,957	389,425,722
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	53,936,910	47,158,124
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	42,577,381	39,299,264
5	Amortization of	1,774,436	1,985,481
6		97,406	97,406
7			
8	Deferred Income Taxes (Net)	-2,010,537	-4,281,026
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	-8,709,095	933,178
11	Net (Increase) Decrease in Inventory	-3,306,478	-3,346,452
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-3,419,090	-10,628,118
14	Net (Increase) Decrease in Other Regulatory Assets	-1,242,181	-3,290,198
15	Net Increase (Decrease) in Other Regulatory Liabilities		
16	(Less) Allowance for Other Funds Used During Construction	-10,492	-1,457
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	-306,582	9,808,806
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	79,402,662	77,737,922
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-132,294,280	-122,833,414
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	1,301,343	1,436,770
31	Other (provide details in footnote):	-70,901	1,492,524
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-133,666,524	-122,777,660
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		1,038,120
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-133,666,524	-121,739,540
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):	88,117,862	43,895,475
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	88,117,862	43,895,475
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-2,855,000	
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-31,000,000	
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock		
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	54,262,862	43,895,475
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-1,000	-106,143
87			
88	Cash and Cash Equivalents at Beginning of Period	5,966	112,109
89			
90	Cash and Cash Equivalents at End of period	4,966	5,966

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/16/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 120 Line No.: 18 Column: b

$ 691,929	Bad debt expense
$ 552,249	Deferred financing cost amortization
$ 1,297,615	Employee benefit plan expense
$-1,739,000	Contributions to defined benefit pension plan
$ -144,090	Mark-to-market gain on derivative asset
$ 3,158,629	Non-cash charges to income offset in regulatory assets and liabilities
$-3,254,965	Other changes in current and non-current assets
$ -868,949	Other changes in current and non-current liabilities
$ -306,582	

Schedule Page: 120 Line No.: 18 Column: c

$ 608,531	Bad debt expense
$ 474,763	Deferred financing costs
$ 778,298	Benefit plan expense
$-1,753,000	Benefit plan contribution
$ 2,821,970	Change in Regulatory Assets and Liabilities Non-current
$ 103,998	Other changes in current and non-current assets
$ 1,356,979	Other changes in current and non-current liabilities
$ 5,417,267	Preliminary survey expenses related to abandoned project
$ 9,808,806	

Schedule Page: 120 Line No.: 31 Column: b

$ 188,786	Plant removal costs net of salvage value
$-259,687	Other investments
$ -70,901	

Schedule Page: 120 Line No.: 31 Column: c

$1,683,357	Plant removal costs net of salvage value
$ -190,833	Other investments
$1,492,524	

Schedule Page: 120 Line No.: 67 Column: b

$55,000,000	Proceeds from Notes Payable to Parent
$33,117,862	Net borrowings from Money Pool
$88,117,862	

Schedule Page: 120 Line No.: 67 Column: c

$25,000,000	Proceeds from Notes Payable to Parent
$18,895,475	Net borrowings from Money Pool
$43,895,475	

Schedule Page: 120 Line No.: 76 Column: b

Dividend paid to Parent

Schedule Page: 120 Line No.: 88 Column: b

$1,000	Cash (131)
$4,966	Working Fund (135)
$5,966	

Schedule Page: 120 Line No.: 88 Column: c

$107,142	Cash (131)
$ 4,967	Working Fund (135)
$112,109	

Schedule Page: 120 Line No.: 90 Column: b

Working Fund (135)

Schedule Page: 120 Line No.: 90 Column: c

$1,000	Cash (131)
$4,966	Working Fund (135)
$5,966	

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

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SEE PAGE 123 FOR REQUIRED INFORMATION.

NOTES TO FINANCIAL STATEMENTS
December 31, 2020 and 2019

(1) BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Power, Inc., doing business as Black Hills Energy ("South Dakota Electric,", the "Company," "we," "us" or "our") is a regulated electric utility serving customers in Montana, South Dakota and Wyoming. We are a wholly-owned subsidiary of Black Hills Corporation ("BHC" or "Parent"), a public registrant listed on the New York Stock Exchange.

Basis of Presentation

The financial statements include the accounts of Black Hills Power, Inc. and also our ownership interests in the assets, liabilities and expenses of our jointly owned facilities (Note 4).

The financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (GAAP). Additionally, these requirements differ from GAAP related to the presentation of certain items discussed below.

<u>Financial Statement Presentation and Basis of Accounting</u>

The financial statements are presented on the basis of the accounting requirements of FERC as set forth in its applicable Uniform System of Accounts and this report differs from GAAP. The significant differences consist of the following:

- The accumulated reserve for estimated removal costs is included in the accumulated provision for depreciation for FERC reporting. For GAAP reporting it is reported as a regulatory liability.
- Deferred financing costs are presented in deferred debits on the balance sheet for FERC reporting. For GAAP reporting, these are presented net within long-term debt.
- Unbilled revenue is presented in Accrued Utility Revenues for FERC reporting and presented in Accounts Receivable for GAAP reporting.
- Accumulated deferred tax assets and liabilities are classified in the balance sheet as gross deferred debits and credits, respectively, while GAAP presentation reflects either a net deferred asset or liability.
- Uncertain tax positions related to temporary differences are classified in the Balance Sheets within the deferred tax accounts in accordance with regulatory treatment, as compared to other noncurrent liabilities for GAAP purposes. In addition, interest related to uncertain tax positions is recognized in interest expense in accordance with regulatory treatment, as compared to income tax expense for GAAP purposes.
- Regulatory assets and liabilities are classified as current and noncurrent for GAAP, while FERC classifies all regulatory assets and liabilities as noncurrent deferred debits and credits, respectively.
- Certain commodity trading purchases and sales transactions are presented gross as expense and revenues for the FERC presentation; however, the net margin is reported as net sales for the GAAP presentation.
- Various revenues and expenses are presented as other income and income deductions for the FERC presentation and reported as operating income and expense for the GAAP presentation.
- Only the service cost component of net periodic pension and post-retirement benefit costs can be capitalized for GAAP reporting. However, all cost components of net periodic pension and post-retirement benefit costs are eligible for capitalization under FERC regulations.

- Capital and operating leases are both classified as capital leases on the balance sheet for FERC reporting. For GAAP reporting, these are presented separately.

Use of Estimates

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

COVID-19 Pandemic

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

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

Cash and Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents. As of December 31, 2020 and 2019, we have no cash equivalents.

Accounts Receivable and Allowance for Credit Losses

Accounts receivable 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 amounts net of allowance for credit losses.

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

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

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

Description	Balance at	Additions charged to costs	Deductions charged to costs	Balance at end

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) __ A Resubmission	04/16/2021	2020/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

	beginning of year	and expenses	and expenses	of year
	(in thousands)			
Allowance for credit losses (Account 144):				
2020	$ 160	$ 2,345	$ (2,249)	$ 256
2019	$ 138	$ 899	$ (877)	$ 160

Materials, Supplies and Fuel

Materials, supplies and fuel used for construction, operation and maintenance purposes are recorded using the weighted-average cost method.

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. Deferred financing costs are presented on the balance sheet within Deferred Debits - Unamortized Debt Expenses (181). See additional information in Note 5.

Regulatory Accounting

Our regulated operations are subject to cost-of-service regulation and earnings oversight from federal and state regulatory commissions. We account for income and expense items in accordance with accounting standards for regulated operations:

- Certain costs, which would otherwise be charged to expense or OCI, are deferred as regulatory assets based on the expected ability to recover the costs in future rates.

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

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

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

As of December 31, 2020 and 2019, we had total regulatory assets of $72 million and $75 million respectively, and total regulatory liabilities of $102 million and $107 million respectively. See Note 7 for further information.

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. 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 Utility plant on the accompanying Balance Sheets.

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. At the time of such retirement, the accumulated provision for depreciation is charged with the original cost of the property retired and also for the net cost of removal. The amounts capitalized are included in Property, plant and equipment on the accompanying Balance Sheets.

Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made. For investments in property, plant and equipment that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary. No impairment loss was recorded during the years ended December 31, 2020 and 2019.

Depreciation provisions for regulated electric property, plant and equipment are computed on a straight-line basis using an annual composite rate of 2.2% in 2020 and 2.2% in 2019.

Derivatives and Hedging Activities

Derivatives are measured at fair value and recognized as either assets or liabilities on the 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.

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

See Note 6 for additional information.

Fair Value Measurements

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

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

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

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

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels. We record transfers, if necessary, between levels at the end of the reporting period for all of our financial instruments.

Transfers into Level 3, if any, occur when significant inputs used to value the derivative instruments become less observable, such as a significant decrease in the frequency and volume in which the instrument is traded, negatively impacting the availability of observable pricing inputs. Transfers out of Level 3, if any, occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery date of a transaction becomes shorter, positively impacting the availability of observable pricing inputs. We currently do not have any Level 3 investments.

Valuation Methodologies for Derivatives

Our wholesale electric energy commodity contracts are valued using the market approach and include wholesale power contracts that do not meet the normal purchases and normal sales exception. For these derivative instruments, the fair value is obtained by utilizing a nationally recognized service that obtains observable inputs to compute the fair value.

Additional fair value information is included in Notes 6 and 11.

Income Taxes

We file a federal income tax return with other members of the Parent's consolidated group. For financial statement purposes, federal income taxes are allocated to the individual companies based on amounts calculated on a separate return basis.

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.

We use the deferral method of accounting for investment tax credits as allowed by our rate-regulated jurisdictions. Such a method results in the investment tax credit 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 Other interest expense on the 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 within deferred tax accounts in accordance with regulatory treatment on the accompanying Balance Sheets. See Note 9 for additional information.

Change in Accounting Principle - Pension Accounting Asset Method

Effective January 1, 2020, we changed our method of accounting for net periodic benefit cost. Prior to the change, the Company used a calculated value for determining market-related value of plan assets which amortized the effects of gains and losses over a five-year period. Effective with the accounting change, the Company used a calculated value for the return-seeking assets (equities) in the portfolio and fair value for the liability-hedging assets (fixed income). See Note 11 for additional information.

Recently Issued Accounting Standards

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

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

Simplifying the Accounting for Income Taxes, ASU 2019-12

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

Recently Adopted Accounting Standards

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

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

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

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 requirements for recording implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. As a result, certain categories of implementation costs that previously would have been charged to expense as incurred are now capitalized as prepayments and amortized over the term of the arrangement. We adopted this standard prospectively on January 1, 2020. Adoption of this guidance did not have a material impact on our financial position, results of operations or cash flows.

(2) 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 electric utility services tariffs - Our regulated operations, as defined by ASC 980, 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 commodity electricity and 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 regulated utility sales are subject to regulatory-approved tariffs.

- Power sales agreements - We have long-term wholesale power sales agreements with other load serving entities for the sale of excess power from owned generating units. In addition to these long-term contracts, the Company also sells 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.

The following table depicts the disaggregation of revenue, including intercompany revenue, from contracts with customers by customer type and timing of revenue recognition. Sales tax and other similar taxes are excluded from revenues.

	Year ended December 31,	
	2020	2019
	(in thousands)	
Customer types:		
Retail	$ 203,452	202,569
Wholesale	31,814	30,899
Market - off-system sales	15,655	16,475
Transmission/Other	53,103	50,329
Revenue from contracts with customers	304,024	300,272
Other revenues	204	2,767
Total revenues	$ 304,228	303,039
Timing of revenue recognition:		
Services transferred over time	$ 304,024	300,272
Revenue from contracts with customers	$ 304,024	300,272

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 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 revenue accounted for under separate accounting guidance, including alternative revenue programs revenue under ASC 980.

Significant Judgments and Estimates

Unbilled Revenue

To the extent that deliveries have occurred but a bill has not been issued, the Company accrues an estimate of the revenue since the latest billing. This estimate is calculated based on 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 Accrued Utility Revenues on the accompanying 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 and is further discussed in Note 1.

(3) PROPERTY PLANT AND EQUIPMENT

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

	2020	2020 Weighted Average Useful Life (in years)	2019	2019 Weighted Average Useful Life (in years
Electric plant:				
Production	664,374	43	617,250	46
Transmission	241,401	50	235,390	51
Distribution	473,031	45	431,783	46
Plant acquisition adjustment (a)	4,870	32	4,870	32
General	169,324	28	165,341	29
Operating lease assets	16,576		16,539	
Total plant-in-service	1,569,576		1,471,173	
Construction work in progress	35,882		44,768	
Total electric plant	1,605,458		1,515,941	
Less accumulated depreciation and amortization	(452,452)		(464,309)	

Electric plant net of accumulated depreciation and amortization	1,153,006		1,051,632	

(a) The plant acquisition adjustment is included in rate base and is being recovered with 11 years remaining.

(4) JOINTLY OWNED FACILITIES

Our 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 Statements of Income. Each owner of the facility is responsible for financing its investment in the jointly-owned facilities.

Wyodak Plant

We own a 20% interest in the Wyodak Plant (the "Plant"), a coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp owns the remaining ownership percentage and operates the Wyodak Plant. We receive our proportionate share of the Wyodak Plant's capacity and are committed to pay our proportionate share of it's additions, replacements and operating and maintenance expenses.

Transmission Tie

We own a 35% share of a Direct Current transmission tie that interconnects the Western and Eastern transmission grids, which are independently-operated transmission grids serving the western and eastern United States, respectively. Basin Electric Power Cooperative owns the remaining ownership percentage. This transmission tie allows us to buy and sell energy in the Eastern grid without having to isolate and physically reconnect load or generation between the two transmission grids, thus enhancing the reliability of our system. It accommodates scheduling transactions in both directions simultaneously, provides additional opportunities to sell excess generation or to make economic purchases to serve our native load and contract obligations, and enables us to take advantage of power price differentials between the two grids. The total transfer capacity of the tie is 400 MW, including 200 MW from West to East and 200 MW from East to West. We are committed to pay our proportionate share of the additions and replacements and operating and maintenance expenses of the transmission tie.

Wygen III

We own a 52% interest in 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. We retain responsibility for plant operations.

Cheyenne Prairie

We own 55 MW of Cheyenne Prairie, a 95 MW gas-fired power generation facility which includes one combined-cycle combustion turbine located in Cheyenne, Wyoming. Wyoming Electric, our related party operating in the Cheyenne, Wyoming area, owns the remaining 40 MW. BHSC is responsible for plant operations. We are committed to pay our proportionate share of the additions, replacements and operating and maintenance expenses.

Corriedale

Corriedale, a 52.5 MW wind farm near Cheyenne, Wyoming, was placed into commercial operation on November 30, 2020. This wind farm serves as the dedicated wind energy supply for Renewable Ready customers in South Dakota and Wyoming. We own 32.5 MW and Wyoming Electric owns 20 MW of this wind farm. We are committed to pay our proportionate share of the additions, replacements and operating and maintenance expenses.

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

Interest in jointly-owned facilities	Plant in Service	Construction Work in Progress	Accumulated Depreciation
Wyodak Plant	$ 116,074	$ 2,249	$ (67,762)
Transmission Tie	$ 26,179	$ 509	$ (7,103)
Wygen III	$ 142,739	$ 582	$ (24,783)
Cheyenne Prairie	$ 93,972	$ 1,065	$ (17,001)
Corriedale	$ 50,918	$ —	$ (272)

(5) LONG-TERM DEBT

Long-term debt outstanding at December 31 was as follows (in thousands):

		Interest Rate at	Balance Outstanding	
	Due Date	December 31, 2020	December 31, 2020	December 31, 2019
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
Less unamortized debt discount			(78)	(82)
Series 94A Debt (a)	June 1, 2024	N/A	—	2,855
Total Long-term Debt			$ 339,922	$ 342,773

(a) Variable interest rate at December 31, 2019.

Amortization of Deferred Financing Costs

Net deferred financing costs of approximately $2.4 million and $2.6 million were recorded on the accompanying Balance Sheets in Deferred Debits - Unamortized Debt Expenses (181) at December 31, 2020 and 2019, respectively, and are being amortized over the term of the debt. Amortization of deferred financing costs of approximately $0.2 million for the year ended December 31, 2020 and $0.1 million for the year ended December 31, 2019 are included in Interest Charges - Amort. of Debt Disc. And Expense (428) on the accompanying Statements of Income.

Debt Covenants

Substantially all of our property is subject to the lien of the indenture securing our first mortgage bonds. First mortgage bonds may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures. We were in compliance with our debt covenants at December 31, 2020.

Debt Transactions

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

Long-term Debt Maturities

Scheduled maturities of our outstanding long-term debt (excluding unamortized discounts and unamortized deferred financing costs) are as follows (in thousands):

2021	$ —
2022	$ —
2023	$ —
2024	$ —
2025	$ —
Thereafter	$ 340,000

(6) DERIVATIVES AND FAIR VALUE MEASUREMENTS

Market and Credit Risk Disclosures

Our activities in the regulated energy sector 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.

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 wholesale electric power marketing activities and our fuel procurement for our gas-fired generation assets which include market fluctuations due to unpredictable factors such as the COVID-19 pandemic, weather, market speculation, transmission constraints, and other factors that may impact electric supply and demand; and

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

Credit Risk

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

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

We perform ongoing credit evaluations of our customers and adjust credit limits based on payment history and the customers' current creditworthiness, as determined by review of their current credit information. We maintain a provision for estimated credit losses based upon historical experience, changes in current market conditions, expected losses and any specific customer collection issue that is identified.

We continue to monitor COVID-19 impacts and changes to customer load, consistency in customer payments, requests for deferred or discounted payments, and requests for changes to credit limits to quantify estimated future financial impacts to the allowance for credit losses. During the year ended December 31, 2020, the potential economic impact of the COVID-19 pandemic was considered in forward looking projections related to write-off and recovery rates, and did not have a material impact to the allowance for credit losses and bad debt expense.

Derivatives

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

The contract or notional amounts and terms of the derivative commodity instruments held at our utility are composed of both long and short positions. We were in a net long position as of:

	December 31, 2020		December 31, 2019	
	MWh	Maximum Term (months)	MWh	Maximum Term (months)
Wholesale power contracts (a)	219,000	12	—	0

(a) Volumes exclude contracts that qualify for the normal purchases and normal sales exception.

From time to time we utilize risk management contracts including interest rate swaps to fix the interest on variable rate debt or to lock in the Treasury yield component associated with anticipated issuance of senior notes. In August 2002, we entered into a treasury lock, which are interest rate swaps, to hedge $50 million of our First Mortgage Bonds due on August 15, 2032. The treasury lock cash settled on August 8, 2002, the bond pricing date, and resulted in a $1.8 million loss. The treasury lock is designated as a cash flow hedge and the resulting loss is carried in Accumulated other comprehensive loss and is being amortized over the life of the First Mortgage Bonds.

As of December 31, 2020, we had no outstanding interest rate swap agreements.

Derivatives by Balance Sheet Classification

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

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

	Balance Sheet Location	December 31, 2020	December 31, 2019
Derivatives not designated as hedges:			
Asset derivative instruments:			
Current commodity derivatives	Derivative Instruments Assets (175)	$ 1,065	$ —
Liability derivative instruments:			
Current commodity derivatives	Derivative Instruments Liabilities (244)	$ (921)	$ —
Total derivatives not designated as hedges		$ 144	$ —

Derivatives Designated as Hedges

The impacts of cash flow hedges on our Statements of Income are presented below for the year ended December 31, 2020 and 2019.

		Twelve Months Ended December 31,	
		2020	2019
Derivatives in Cash Flow Hedging Relationships	Income Statement Location	Amount of Gain/(Loss) Reclassified from AOCI into Income	
		(in thousands)	
Interest rate swaps	Interest and Dividend Income (419)	$ (64)	$ (64)
Total		$ (64)	$ (64)

As of December 31, 2020, $0.1 million of net losses related to our interest rate swaps are expected to be reclassified from AOCI into earnings within the next 12 months.

Derivatives Not Designated as Hedges

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

		2020	2019
Derivatives Not Designated as Hedging	Income Statement Location	Amount of Gain/(Loss) on Derivatives	

Instruments		Recognized in Income	
		(in thousands)	
Commodity derivatives	Misc Non Operating Income (421)	$ 144	$ —
		$ 144	$ —

The unrealized gains and losses arising from these derivatives are recognized in the Statements of Income.

Fair Value Measurements

Recurring Fair Value Measurements

Derivatives

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

	As of December 31, 2020				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives	$ —	$ 1,065	$ —	$ —	1,065
Liabilities:					
Commodity derivatives	$ —	$ (921)	$ —	$ —	(921)

	As of December 31, 2019				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives	$ —	$ —	$ —	$ —	—
Liabilities:					
Commodity derivatives	$ —	$ —	$ —	$ —	—

Pension and Postretirement Plan Assets

A discussion of the fair value of our Pension and Postretirement Plan assets is included in Note 11.

Other fair value measures

The carrying amount of cash and cash equivalents, restricted cash and equivalents, Money pool notes payable and Notes payable to Parent approximate fair value due to their liquid or short-term nature. Cash, cash equivalents, and restricted cash are classified in Level 1 in the fair value hierarchy. Money pool notes payable and Notes payable to Parent are not traded on an exchange and are classified in Level 2 in the fair value hierarchy.

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

	2020		2019	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt [(a)]	$ 339,922	$ 504,374	$ 342,773	$ 412,894

(a) Long-term debt is valued based on observable inputs available either directly or indirectly for similar liabilities in active markets and therefore is classified in Level 2 in the fair value hierarchy.

(7) REGULATORY MATTERS

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

	2020	2019
Regulatory assets		
Deferred taxes on AFUDC [(b)]	4,650	4,928
Employee benefit plans [(c)]	19,244	20,562
Deferred energy and fuel cost adjustments [(a)]	24,519	23,202
Deferred taxes on flow through accounting [(a)]	11,943	9,801
Decommissioning costs [(b)]	4,436	6,211
Vegetation management [(a)]	5,759	8,062
Other regulatory assets [(a)]	1,348	1,843
Total Other Regulatory Assets (182.3)	71,899	74,609
Regulatory liabilities		
Employee benefit plans and related deferred taxes [(c)]	6,220	7,022
Excess deferred income taxes [(c)]	95,109	99,745
Other regulatory liabilities [(c)]	875	441

Total Other Regulatory Liabilities (254)	102,204	107,208

(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 increases in rates.

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 other post-retirement benefit plans in regulatory assets rather than in accumulated other comprehensive income. In addition, this regulatory asset includes the income tax effect of the adjustment required under accounting for compensation-defined benefit plans to record the full pension and post-retirement benefit obligations.

Deferred Energy and Fuel Cost Adjustments - Deferred energy and fuel cost adjustments represent the cost of electricity delivered to our 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. We file periodic quarterly, semi-annual and/or annual filings to recover these costs based on the respective cost mechanisms approved by the applicable state utility commissions.

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 - We received approval in 2014 for regulatory treatment on the remaining net book values and decommissioning costs of our decommissioned coal plants.

Vegetation Management Costs - We received approval in 2013 for regulatory treatment on vegetation management maintenance costs for our distribution system rights-of-way.

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

Employee Benefit Plans **-** Employee benefit plans represent the cumulative excess of pension and other postretirement benefit 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.

Excess Deferred Income Taxes - The revaluation of our deferred tax assets and liabilities due to the passage of the TCJA is recorded as an excess deferred income tax to be refunded to customers primarily using the normalization principles as prescribed in the TCJA. See Note 9 for additional information.

Regulatory Activity

TCJA

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

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

Settlement

On January 7, 2020, South Dakota Electric received approval from the South Dakota Public Utilities Commission 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 in Other deductions (Account 426.1) $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 Transmission Facility Adjustment and Environmental Improvement Adjustment.

FERC Formula Rate

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

(8) LEASES

We have a ground lease for the Wygen III generating facility with an affiliate and communication tower site and operation center facility leases with third parties. Our leases have remaining terms ranging from one year to 29 years, including options to extend that are reasonably certain to be exercised.

Most of our leases do not contain a readily determinable discount rate. Therefore, the present value of future lease payments is generally calculated using our applicable incremental borrowing rate (weighted-average of 4.35% as of December 31, 2020).

The components of lease expense were as follows (in thousands):

	Income Statement Location	2020	2019
Operating lease cost	Operating Expenses (401)	$ 929	$ 908
Variable lease cost	Operating Expenses (401)	173	137

Total lease cost		$ 1,102	$ 1,045

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

	Balance Sheet Location	As of December 31, 2020	As of December 31, 2019
Assets:			
Operating leases	Utility Plant (101-106, 114)	$ 16,576	$ 16,538
Operating leases	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	(2,472)	(2,164)
Total lease assets		$ 14,104	$ 14,374
Liabilities:			
Operating leases	Obligations Under Capital Leases - Noncurrent (227)	$ 13,802	$ 14,105
Operating leases	Obligations Under Capital Leases - Current (243)	317	293
Total lease liabilities		$ 14,119	$ 14,398

Supplemental cash flow information related to leases was as follows (in thousands):

	2020	2019
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 922	$ 912
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases	$ 23	$ —

	As of December 31, 2020	As of December 31, 2019
Weighted average remaining lease term (years):		
Operating leases	29 years	30 years
Weighted average discount rate:		
Operating leases	4.4 %	4.3 %

Scheduled maturities of operating lease liabilities for future years were as follows (in thousands):

	Total
2021	$ 924

2022	912
2023	909
2024	907
2025	852
Thereafter	20,295
Total lease payments	$ 24,799
Less imputed interest	10,680
Present value of lease liabilities	$ 14,119

(9) INCOME TAXES

Income Tax Expense

Income tax expense for the years ended December 31 was as follows (in thousands):

	2020	2019
Current income tax expense (Accounts 409.1 and 409.2)	$ 7,352	$ 13,782
Deferred income tax (benefit) (Accounts 410.1 and 411.1)	(2,010)	(4,281)
Total income tax expense (benefit)	$ 5,342	$ 9,501

Effective Tax Rates

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

	2020	2019
Federal statutory rate	21.0 %	21.0 %
Amortization of excess deferred and investment tax credits (a)	(6.3)%	(3.0)%
Flow through adjustments (b)	(2.4)%	(1.5)%
Tax credits (c) (d)	(4.4)%	— %
Uncertain tax benefits	1.3 %	— %
Other	(0.1)%	0.3 %
Effective tax rate	9.0 %	16.8 %

(a) Primarily TCJA — see Tax Reform section below for further details.

(b) Flow-through adjustments related primarily to an accounting method change for tax purposes that allows us to take a current tax deduction for repair costs. We recorded a deferred income tax liability in recognition of the temporary difference created between book and tax treatment and we flowed the tax benefit through to tax expense.
(c) In November 2020, the Corriedale qualifying wind facility was placed in service and was eligible for production tax credits.
(d) In 2020, we completed a research and development study which encompassed tax years from 2013 to 2019.

Deferred Tax Assets and Liabilities

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

	2020	2019
Deferred tax assets:		
Regulatory liabilities	24,920	25,623
Other	13,063	9,050
Total deferred tax assets — (Account 190)	37,983	34,673
Deferred tax liabilities:		
Accelerated depreciation and other plant related differences	(129,644)	(128,708)
Regulatory assets	(7,313)	(7,193)
Deferred costs	(7,923)	(8,264)
Other	(8,146)	(6,276)
Total deferred tax liabilities (Accounts 282 and 283)	(153,026)	(150,441)
Net deferred tax assets (liabilities)	$ (115,043)	$ (115,768)

Unrecognized Tax Benefits

The following table reconciles the total amounts of unrecognized tax benefits, without interest, included in deferred tax accounts in accordance with regulatory treatment on the accompanying Balance Sheet (in thousands):

	2020	2019
Unrecognized tax benefits at January 1	$ 216	$ 249
Additions for prior year tax positions	181	—
Additions for current year tax positions	616	—
Reductions for prior year tax positions	(97)	(33)
Unrecognized tax benefits at December 31	$ 916	$ 216

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is not material to the financial results of the Company.

It is the Company's continuing practice to recognize interest and/or penalties related to income tax matters in Other interest expense. During the years ended December 31, 2020 and 2019, the interest expense recognized was not material to the financial results of the Company.

We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of any audits or the expiration of statutes of limitations on or before December 31, 2021.

We file income tax returns in the United States federal jurisdictions as a member of the BHC consolidated group.

Tax Reform

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 has remeasured the deferred income taxes at the 21% federal tax rate as of December 31, 2017.

The regulatory liability for excess deferred income taxes that is considered protected and unprotected as of December 31 is reflected below (in millions):

Jurisdiction	2020	2019
Protected		
FERC	$ 13.3	$ 13.9
State	67.9	71.0
Total protected	$ 81.2	$ 84.9
Unprotected		
FERC	$ 2.3	$ 2.4
State	11.6	12.4
Total unprotected	$ 13.9	$ 14.8
Total excess deferred income tax liabilities (account 254)	$ 95.1	$ 99.7

In 2018, we received an order from the South Dakota Public Utilities Commission approving a settlement stipulation regarding how customer rates should be reduced for excess deferred income taxes. The settlement stipulation required (i) a refund of protected and non-protected plant asset related excess deferred income taxes pursuant to the average rate assumption method (“ARAM”) and (ii) a refund in 2019 of all non-protected excess deferred income taxes not related to plant assets.
The adjustments to the regulatory liability (account 254) for the year ended December 31, 2020, the estimated amortization period based on regulatory orders, and the accounts where the adjustments and amortization were reported are reflected below (in millions):

Jurisdiction	December 31, 2019	Accounts							December 31, 2020	Amortization Period
		190	236	254	282	283	411	409-411		

				Other			Amort.			
Protected										
FERC	$ 13.9	$ (0.1)	$ —	$ —	$ —	$ —	$ (0.5)	$ —	$ 13.3	(a)
State	71.0	(0.7)	—	—	—	—	(2.4)	—	67.9	(a)
Total protected	$ 84.9	$ (0.8)	$ —	$ —	$ —	$ —	$ (2.9)	$ —	$ 81.2	
Unprotected										
FERC	2.4	$ —	$ —	$ —	$ —	$ —	$ (0.1)	$ —	$ 2.3	(b)
State	12.4	(0.2)	—	—	—	—	(0.6)	—	11.6	(b)
Total unprotected	$ 14.8	$ (0.2)	$ —	$ —	$ —	$ —	$ (0.7)	$ —	$ 13.9	
Total excess deferred income tax liabilities (account 254)	$ 99.7	$ (1.0)	$ —	$ —	$ —	$ —	$ (3.6)	$ —	$ 95.1	

(a) The weighted average amortization period was estimated at 60-80 years under ARAM.
(b) The weighted average amortization period was estimated at 60-80 years under ARAM for plant-related unprotected and 1 year for non-plant unprotected.

The FERC has not yet issued an order regarding how customer rates should be reduced for excess deferred income taxes.

(10) OTHER COMPREHENSIVE INCOME

We record deferred gains (losses) in AOCI related to interest rate swaps designated as cash flow hedges and the amortization of components of our defined benefit plans. 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 Statements of Income for the period, net of tax (in thousands):

	Location on the Statement of Income	Amounts Reclassified from AOCI	
		2020	2019
Gains and Losses on cash flow hedges:			
Interest rate swaps gain (loss)	Misc Non Operating Income (421)	(64)	(64)
Income tax	Income Taxes Federal (409)	13	132
Total reclassification adjustments related to cash flow hedges, net of tax		(51)	68

Amortization of defined benefit plans:			
Actuarial gain (loss)	Misc Non Operating Income (421)	(125)	(65)
Income tax	Income Taxes Federal (409)	26	166
Total reclassification adjustments related to defined benefit plans, net of tax		(99)	101

Balances by classification included within Accumulated other comprehensive loss on the accompanying Balance Sheets were as follows (in thousands):

	Interest Rate Swaps	Employee Benefit Plans	Total
As of December 31, 2019	$ (568)	$ (812)	$ (1,380)
Other comprehensive income (loss) before reclassifications	—	(190)	(190)
Amounts reclassified from AOCI	51	99	150
As of December 31, 2020	$ (517)	$ (903)	$ (1,420)

	Interest Rate Swaps	Employee Benefit Plans	Total
As of December 31, 2018	$ (500)	$ (391)	$ (891)
Other comprehensive income (loss) before reclassifications	—	(320)	(320)
Amounts reclassified from AOCI	(68)	(101)	(169)
As of December 31, 2019	$ (568)	$ (812)	$ (1,380)

(11) EMPLOYEE BENEFIT PLANS

Defined Contribution Plans

BHC sponsors 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 to 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 (Pension Plan)

We have a defined benefit pension plan (“Pension Plan”) covering certain eligible employees. 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. BHC's 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 allocation range to return-seeking and liability-hedging assets is determined based on the funded status of the Plan. As of December 31, 2020, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 28% to 36% return-seeking assets and 64% to 72% liability-hedging assets.

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

Pension Plan Assets

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

	2020	2019
Equity securities	21 %	20 %
Real estate	3 %	3 %
Fixed income funds	69 %	71 %
Cash and cash equivalents	3 %	2 %
Hedge funds	4 %	4 %
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. Pre-65 retirees receive their retiree medical benefits through the Black Hills self-insured retiree medical plans. Healthcare coverage for Medicare-eligible BHP retirees is provided through an individual market healthcare exchange. The Healthcare Plan has no assets. We fund on a cash basis as benefits are paid.

Plan Contributions

Contributions to the Pension Plan are cash contributions made directly to the Master Trust. Healthcare benefits include company and participant paid premiums.

Contributions for the years ended December 31 were as follows (in thousands):

	2020	2019
Defined Contribution Plans		
Company Retirement Contribution	$ 960	$ 888
Matching Contributions	$ 1,328	$ 1,275
Defined Benefit Plans		
Defined Benefit Pension Plan	$ 1,739	$ 1,753
Non-Pension Defined Benefit Postretirement Healthcare Plan	$ 620	$ 739
Supplemental Non-qualified Defined Benefit Plan	$ 321	$ 266

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

Fair Value Measurements

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

Pension Plan	**December 31, 2020**					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV (a)	Total
Common Collective Trust - Cash and Cash Equivalents	$ —	$ 2,278	$ —	$ 2,278	$ —	$ 2,278
Common Collective Trust - Equity	—	13,590	—	13,590	—	13,590
Common Collective Trust - Fixed Income	—	44,010	—	44,010	—	44,010
Common Collective Trust - Real Estate	—	—	—	—	1,937	1,937
Hedge Funds	—	—	—	—	2,365	2,365
Total investments measured at fair value	$ —	$ 59,878	$ —	$ 59,878	$ 4,302	$ 64,180

Pension Plan	**December 31, 2019**					
				Total Investments		Total Fair

	Level 1	Level 2	Level 3	Measured at Fair Value	NAV (a)	Value
AXA Equitable General Fixed Income	$ —	$ 8	$ —	$ 8	$ —	$ 8
Common Collective Trust - Cash and Cash Equivalent	—	978	—	978	—	978
Common Collective Trust - Equity	—	12,072	—	12,072	—	12,072
Common Collective Trust - Fixed Income	—	42,449	—	42,449	—	42,449
Common Collective Trust - Real Estate	—	—	—	—	1,974	1,974
Hedge Funds	—	—	—	—	2,709	2,709
Total investments measured at fair value	$ —	$ 55,507	$ —	$ 55,507	$ 4,683	$ 60,190

(a) Certain investments that are measured at fair value using Net Asset Value “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.

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

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. 10% of the shares may be redeemed at the end of each month with a 15-day notice and full redemptions are available at the end of each quarter with 60-day notice and is limited to a percentage of the total net assets value of the fund. The net asset values are based on the fair value of each fund’s underlying investments. There are no unfunded commitments related to these hedge funds.

Other Plan Information

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

Benefit Obligations

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
As of December 31,	2020	2019	2020	2019	2020	2019
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 67,061	$ 61,919	$ 3,246	$ 2,992	$ 5,176	$ 5,055
Service cost	368	365	—	—	157	148
Interest cost	1,852	2,410	84	115	129	186
Actuarial (gain) loss	5,983	7,482	240	405	150	507
Benefits paid	(5,814)	(5,234)	(321)	(266)	(619)	(739)
Plan participants transfer to affiliate	(54)	119	—	—	—	(77)
Plan participants' contributions	—	—	—	—	107	96
Projected benefit obligation at end of year	$ 69,396	$ 67,061	$ 3,249	$ 3,246	$ 5,100	$ 5,176

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) __ A Resubmission	04/16/2021	2020/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Fair Value of Employee Benefit Plan Assets

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
As of December 31,	2020	2019	2020	2019	2020	2019
Beginning fair value of plan assets	$ 60,190	$ 54,664	$ —	$ —	$ —	$ —
Investment income (loss)	8,100	8,902	—	—	—	—
Benefits paid	1,739	1,753	(321)	266	513	643
Participant contributions	—	—	—	—	107	96
Employer contributions	(5,814)	(5,234)	321	(266)	(620)	(739)
Plan participants transfer to affiliate	(35)	105	—	—	—	
Ending fair value of plan assets	$ 64,180	$ 60,190	$ —	$ —	$ —	$ —

Amounts Recognized in the Balance Sheets

As of December 31,	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2020	2019	2020	2019	2020	2019
Other Regulatory Assets (182.3)	$ 18,928	$ 20,117	$ —	$ —	$ —	$ —
Miscellaneous Current and Accrued Liabilities (242)	$ —	$ —	$ 320	$ 321	$ 629	$ 586
Accumulated Provision for Pensions and Benefits (228.3)	$ 5,216	$ 7,121	$ 2,929	$ 2,925	$ 4,471	$ 4,590
Other Regulatory Liabilities (254)	$ —	$ —	$ —	$ —	$ 1,189	$ 1,675

Accumulated Benefit Obligation

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
As of December 31,	2020	2019	2020	2019	2020	2019
Accumulated benefit obligation	$ 67,579	$ 65,225	$ 3,249	$ 3,246	$ 5,100	$ 5,176

Components of Net Periodic Expense

For the years ended December 31,	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2020	2019	2020	2019	2020	2019
Service Cost	$ 367	$ 365	$ —	$ —	$ 157	$ 148

Interest Cost	1,852	2,410	84	114	129	186
Expected return on assets	(3,125)	(3,405)	—	—	—	—
Amortization of prior service cost (credits)	—	10	—	—	(335)	(336)
Recognized net actuarial loss (gain)	2,043	1,221	125	65	—	—
Net periodic expense	$ 1,137	$ 601	$ 209	$ 179	$ (49)	$ (2)

Change in Accounting Principle - Pension Accounting Asset Method

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

We evaluated the effect of this change in accounting method and deemed it immaterial to the historical and current financial statements and therefore did not account for the change retrospectively. Accordingly, the Company calculated the cumulative difference using a calculated value versus fair value to determine market-related value for liability-hedging assets of the portfolio. The cumulative effect of this change, as of January 1, 2020, resulted in an immaterial change to prior service costs.

AOCI Amounts (After-Tax)

As of December 31,	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2020	2019	2020	2019	2020	2019
Net (gain) loss	$ —	$ —	$ 903	$ 812	$ —	$ —
Total amounts included in AOCI, after-tax not yet recognized as components of net periodic expense	$ —	$ —	$ 903	$ 812	$ —	$ —

Assumptions

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2020	2019	2020	2019	2020	2019
Weighted-average assumptions used to determine benefit obligations:						
Discount rate	2.56 %	3.27 %	2.32 %	3.10 %	2.41 %	3.15 %
Rate of increase in compensation levels	3.34 %	3.49 %	N/A	N/A	N/A	N/A

Weighted-average assumptions used to determine net periodic benefit cost for plan year:						
Discount rate (a)	3.27 %	4.40 %	3.10 %	4.30 %	3.15 %	4.28 %
Expected long-term rate of return on assets (b)	5.25 %	6.00 %	N/A	N/A	2.35 %	3.00 %
Rate of increase in compensation levels	3.49 %	3.52 %	N/A	N/A	N/A	N/A

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

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

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

Estimated Future Benefit Payments

The following benefit payments, 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 Plans
2021	$ 3,686	$ 320	$ 629
2022	$ 3,763	$ 317	$ 606
2023	$ 3,884	$ 314	$ 533
2024	$ 3,985	$ 310	$ 493
2025	$ 3,974	$ 272	$ 442
2026-2030	$ 19,559	$ 1,074	$ 1,727

(12) COMMITMENTS AND CONTINGENCIES

We have the following power purchase and transmission services agreements, not including related party agreements, as of December 31, 2020 (see Note 14 for information on related party agreements):

Contract Type	Counterparty	Fuel Type	Quantity (MW)	Expiration Date
PPA	PacifiCorp	Coal	50	December 31, 2023
TSA (a)	PacifiCorp	N/A	50	December 31, 2023
PPA	Platte River Power Authority	Wind	12	September 30, 2029
PPA	Fall River Solar, LLC	Solar	80	Pending Completion (b)

(a) This is a firm point-to-point transmission service agreement that provides 50 MW of capacity and energy to be transmitted annually.

(b) This agreement related to a new solar facility currently being constructed and will expire 20 years after construction completion, which is expected by the end of 2022.

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

Contract Type	Counterparty	Fuel Type	2020	2019
PPA	PacifiCorp	Coal	$ 5,897	$ 7,477
TSA	PacifiCorp	N/A	$ 1,776	$ 1,741
Gas transport capacity	Thunder Creek (a)	N/A	$ —	$ 422
PPA	Platte River Power Authority	Wind	$ 715	$ 688

(a) Agreement with Thunder Creek for gas transport capacity, expired in October 2019.

Future Contractual Obligations

The following is a schedule of future minimum payments required under power purchase, transmission services and gas supply agreements (in thousands):

2021	$ 6,463
2022	$ 6,203
2023	$ 6,203
2024	$ —
2025	$ —
Thereafter	$ —

Power Sales Agreements

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, MDU will be provided with 25 MW from our other generation facilities or from system purchases with reimbursement of costs by MDU. This agreement expires January 31, 2023.

- An agreement to serve MDU capacity and energy up to a maximum of 50 MW in excess of Wygen III ownership. This agreement expires December 31, 2023. Additionally, we have 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.

- 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, we 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.

- We have 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 terms of the contract run from June 1 through May 31 for each interval listed below. This contract is unit-contingent based on the availability of our Wygen III and Neil Simpson II plants, with decreasing capacity purchased over the term of the agreement. The unit-contingent capacity amounts from Wygen III and Neil Simpson II are as follows:

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

- An agreement through December 31, 2021 to provide 50 MW of energy to Macquarie Energy, LLC during heavy and light load timing intervals.

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. They can result in increased capital expenditures, operating and other costs as a result of compliance, remediation and monitoring obligations. 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.

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 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 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.

(13) RELATED-PARTY TRANSACTIONS

Dividends to Parent

In 2020, we paid dividends of $31 million to our Parent. We did not pay any dividends in 2019.

Receivables and Payables

We have accounts receivable and accounts payable balances related to transactions with other BHC subsidiaries. These balances as of December 31 were as follows (in thousands):

	2020	2019
Accounts Receivable from Associated Companies (146)	$ 19,151	$ 13,038
Accounts Payable to Associated Companies (234)	$ 40,160	$ 32,121

Money Pool Notes Receivable and Notes Payable

We participate in the Utility Money Pool Agreement (the Agreement). Under the Agreement, we may borrow from the pool; however the Agreement restricts the pool from loaning funds to BHC or to any of BHC’s non-utility subsidiaries. The Agreement does not restrict us from paying dividends to BHC. Borrowings under the Agreement bear interest at the weighted average daily cost of BHC’s external borrowings as defined under the Agreement, or if there are no external funds outstanding on that date, then the rate will be the daily one-month LIBOR plus 1.0%. The cost of borrowing under the Utility Money Pool was 0.44% at December 31, 2020

We had the following balances with the Utility Money Pool as of December 31 (in thousands):

	2020	2019
Money pool notes payable -- Notes Payable to Associated Companies (233)	$ 90,703	$ 57,585
Money pool interest payable -- Notes Payable to Associated Companies (233)	$ 32	$ 103

Interest expense relating to the Utility Money Pool for the years ended December 31, was as follows (in thousands):

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) __ A Resubmission	04/16/2021	2020/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

	2020	2019
Money pool interest expense -- Interest on Debt to Assoc. Companies (430)	$ 645	$ 775

Notes payable to Parent

	2020	2019
Notes payable to Parent -- Notes Payable to Associated Companies (233)	$ 80,000	$ 25,000

Interest expense relating to our Notes Payable to Parent for the year ended December 31, was as follows (in thousands):

	2020	2019
Notes payable to Parent interest expense -- Interest on Debt to Assoc. Companies (430)	$ 2,171	$ 654

Interest expense allocation from Parent

BHC provides daily liquidity and cash management on behalf of all its subsidiaries. For the years ended December 31, 2020, and 2019, we were allocated $0.4 million and $0.6 million, respectively, of interest expense from BHC.

Other Agreements

We have the following agreements with affiliated entities:

- A Generation Dispatch Agreement with Wyoming Electric which requires us to purchase all of Wyoming Electric's excess energy. Under this same agreement, Wyoming Electric can also purchase off-system energy from us for the purpose of displacing some, or all, of the available energy from a higher-cost resource.

- A shared facilities agreement with Wyoming Electric and Black Hills Wyoming whereby each entity is charged for the use of assets located at the Gillette, Wyoming energy complex by the affiliate entity.

- 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.

- All-in requirements agreements with Wyodak Resources Development Corporation (WRDC), a related party, for the purchase of coal for use at Neil Simpson II, Wyodak Plant, and Wygen III.

- An intercompany agreement with Wyoming Electric to purchase 50% of the output they receive under a separate PPA with Happy Jack Wind Farm, LLC. Their agreement expires September 3, 2028 and provides up to 30 MW of wind energy from the wind farm located near Cheyenne, Wyoming.

- An intercompany agreement with Wyoming Electric to purchase 67% of the output they receive under a separate PPA with Silver Sage Wind Farm, LLC. Their agreement expires September 30, 2029 and provides up to 30 MW of wind energy from the wind farm located near Cheyenne, Wyoming.

- A Generation Dispatch Agreement with Wyoming Electric which requires us to purchase all of their excess energy. Under this same agreement, Wyoming Electric can also purchase off-system energy from us for the purpose of displacing some, or all, of the available energy from a higher-cost resource.

- On October 1, 2014, we entered into a gas transportation service agreement with Wyoming Electric in connection with gas supply for Cheyenne Prairie. The agreement is for a term of 40 years, in which we pay a monthly service and facility fee for firm and interruptible gas transportation.
- A Wygen III Ground Lease with WDRC expiring in 2050 with three automatic renewal terms of 20 years each.
- South Dakota Electric and Wyoming Electric receive certain staffing and management services from BHSC for Cheyenne Prairie.

Related-party Revenue and Purchases

We had the following related-party transactions for the years ended December 31 included in the corresponding captions in the accompanying Statements of Income:

	2020	2019
	(in thousands)	
Operating Revenues:		
Energy sold to Wyoming Electric	$ 762	$ 1,333
Rent from electric properties	$ 3,957	$ 3,583
Horizon Point shared facility revenue	$ 11,360	$ 12,026
Operating Expenses:		
Purchases from WRDC mine	$ 16,863	$ 17,041
Purchase of excess energy from Wyoming Electric	$ 1,633	$ 856
Purchase of renewable wind energy from Wyoming Electric - Happy Jack	$ 2,266	$ 1,968
Purchase of renewable wind energy from Wyoming Electric - Silver Sage	$ 4,136	$ 3,579
Gas transportation service agreement with Wyoming Electric for firm and interruptible gas transportation	$ 311	$ 309
Wygen III ground lease with WRDC mine	$ 1,004	$ 987

Related-party Corporate Support

We had the following corporate support for the years ended December 31:

	2020	2019
	(in thousands)	
Corporate support services and fees from Parent and Black Hills Service Company	$ 45,299	$ 39,667

(14) SUPPLEMENTAL CASH FLOW INFORMATION

Years ended December 31,	2020	2019
	(in thousands)	
Cash (paid) refunded during the period for:		
Interest (net of amounts capitalized)	$ (24,493)	$ (21,909)
Income taxes	$ (21,813)	$ (24,372)
Non-cash investing and financing activities:		
Accrued property, plant and equipment purchases at December 31	$ 12,202	$ 12,305

(15) SUBSEQUENT EVENT

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

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

As a result of this historic event, our natural gas purchases increased by approximately $24 million compared to forecasted base load for the month of February. To fund February natural gas purchases and pipeline transportation charges and provide additional liquidity, BHC entered into a nine-month Credit Agreement on February 24, 2021, that provides for an $800 million unsecured term loan facility. The term loan, which matures on November 23, 2021, has an interest rate based on LIBOR plus 75 basis points, carries no prepayment penalty and is subject to the same covenant requirements as our Revolving Credit Facility. BHC expects to repay a portion of this term loan prior to maturity and refinance the remaining portion in longer-term debt. We utilized the Utility Money Pool to fund our February purchases from this weather event.

Except as described above, there have been no events subsequent to December 31, 2020 which would require recognition in the financial statements or disclosure.

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year		(391,508)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income		(101,166)		
3	Preceding Quarter/Year to Date Changes in Fair Value		(320,057)		
4	Total (lines 2 and 3)		(421,223)		
5	Balance of Account 219 at End of Preceding Quarter/Year		(812,731)		
6	Balance of Account 219 at Beginning of Current Year		(812,731)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income		98,923		
8	Current Quarter/Year to Date Changes in Fair Value		(189,818)		
9	Total (lines 7 and 8)		(90,895)		
10	Balance of Account 219 at End of Current Quarter/Year		(903,626)		

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	(499,752)		(891,260)	[redacted]	[redacted]
2	(67,762)		(168,928)	[redacted]	[redacted]
3			(320,057)	[redacted]	[redacted]
4	(67,762)		(488,985)	47,158,124	46,669,139
5	(567,514)		(1,380,245)	[redacted]	[redacted]
6	(567,514)		(1,380,245)	[redacted]	[redacted]
7	50,822		149,745	[redacted]	[redacted]
8			(189,818)	[redacted]	[redacted]
9	50,822		(40,073)	53,936,910	53,896,837
10	(516,692)		(1,420,318)	[redacted]	[redacted]

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	1,364,803,181	1,338,776,659
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	198,635,636	198,635,636
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	1,563,438,817	1,537,412,295
9	Leased to Others		
10	Held for Future Use	1,266,452	1,266,452
11	Construction Work in Progress	35,881,998	35,881,998
12	Acquisition Adjustments	4,870,308	4,870,308
13	Total Utility Plant (8 thru 12)	1,605,457,575	1,579,431,053
14	Accum Prov for Depr, Amort, & Depl	452,451,971	450,479,191
15	Net Utility Plant (13 less 14)	1,153,005,604	1,128,951,862
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	448,540,793	446,568,013
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant		
22	Total In Service (18 thru 21)	448,540,793	446,568,013
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	3,911,178	3,911,178
33	Total Accum Prov (equals 14) (22,26,30,31,32)	452,451,971	450,479,191

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) BHSC (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
	26,026,522				3
					4
					5
					6
					7
	26,026,522				8
					9
					10
					11
					12
	26,026,522				13
	1,972,780				14
	24,053,742				15
					16
					17
	1,972,780				18
					19
					20
					21
	1,972,780				22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
	1,972,780				33

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) __ A Resubmission	04/16/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 200 Line No.: 3 Column: c

Includes 16,576,394 of Right-of-Use Operating Lease

Schedule Page: 200 Line No.: 18 Column: c

Includes 2,471,920 of Right-of-Use Operating Lease.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)		
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)		
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
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			18
			19
			20
			21
			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents		
4	(303) Miscellaneous Intangible Plant		
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)		
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	233,606	
9	(311) Structures and Improvements	38,595,287	9,159,689
10	(312) Boiler Plant Equipment	241,335,812	-229,004
11	(313) Engines and Engine-Driven Generators	345,156	
12	(314) Turbogenerator Units	122,203,437	209,105
13	(315) Accessory Electric Equipment	22,530,409	-103,094
14	(316) Misc. Power Plant Equipment	3,088,962	105,641
15	(317) Asset Retirement Costs for Steam Production		
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	428,332,669	9,142,337
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights	2,365,975	
38	(341) Structures and Improvements	6,082,790	647,914
39	(342) Fuel Holders, Products, and Accessories	6,534,503	179,578
40	(343) Prime Movers	196,341	-156,910
41	(344) Generators	152,617,511	51,578,117
42	(345) Accessory Electric Equipment	19,803,769	377,009
43	(346) Misc. Power Plant Equipment	303,751	611
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	187,904,640	52,626,319
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	616,237,309	61,768,656

Name of Respondent Black Hills Power, Inc	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report End of 2020/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	10,142,370	3,755
49	(352) Structures and Improvements	1,891,306	24,281
50	(353) Station Equipment	56,657,438	12,570,361
51	(354) Towers and Fixtures	864,826	90,842
52	(355) Poles and Fixtures	98,308,320	-7,168,742
53	(356) Overhead Conductors and Devices	67,264,647	9,226,348
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	6,920	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	235,135,827	14,746,845
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	2,513,440	511,618
61	(361) Structures and Improvements	1,731,626	263,814
62	(362) Station Equipment	99,464,935	11,206,739
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	99,982,605	14,418,498
65	(365) Overhead Conductors and Devices	63,504,369	5,648,785
66	(366) Underground Conduit	10,818,142	2,397,062
67	(367) Underground Conductors and Devices	49,819,325	10,482,153
68	(368) Line Transformers	49,400,971	3,226,467
69	(369) Services	39,155,266	397,319
70	(370) Meters	10,563,256	270,070
71	(371) Installations on Customer Premises	2,634,079	105,200
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	2,195,044	50,397
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	431,783,058	48,978,122
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	6,083,452	
87	(390) Structures and Improvements	80,227,220	2,713,894
88	(391) Office Furniture and Equipment	14,388,097	3,993,086
89	(392) Transportation Equipment	16,075,824	3,212,659
90	(393) Stores Equipment	101,989	336,820
91	(394) Tools, Shop and Garage Equipment	3,987,855	407,263
92	(395) Laboratory Equipment	771,815	45,263
93	(396) Power Operated Equipment	3,156,771	1,116,748
94	(397) Communication Equipment	7,769,752	-355,965
95	(398) Miscellaneous Equipment	945,664	290,558
96	SUBTOTAL (Enter Total of lines 86 thru 95)	133,508,439	11,760,326
97	(399) Other Tangible Property	16,538,594	37,800
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	150,047,033	11,798,126
100	TOTAL (Accounts 101 and 106)	1,433,203,227	137,291,749
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	1,433,203,227	137,291,749

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
					3
					4
					5
					6
					7
			233,606		8
250,704		-233,395	47,270,877		9
2,703,859		-207,720	238,195,229		10
			345,156		11
1,559,697		-707,211	120,145,634		12
596,783	-2,091,127		19,739,405		13
		-44,917	3,149,686		14
					15
5,111,043	-2,091,127	-1,193,243	429,079,593		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
			2,365,975		37
			6,730,704		38
683,710			6,030,371		39
			39,431		40
2,868,605		-1,901,531	199,425,492		41
107,270		-13,669	20,059,839		42
	-674,814		-370,452		43
					44
3,659,585	-674,814	-1,915,200	234,281,360		45
8,770,628	-2,765,941	-3,108,443	663,360,953		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
			10,146,125		48
			1,915,587		49
395,347	2,765,941	-526,962	71,071,431		50
			955,668		51
5,023,337		-8,629	86,107,612		52
5,545,534		-1,968	70,943,493		53
					54
					55
			6,920		56
					57
10,964,218	2,765,941	-537,559	241,146,836		58
					59
			3,025,058		60
4,866		-725	1,989,849		61
524,019		-1,323,413	108,824,242		62
					63
25,594	-10,303	-692,493	113,672,713		64
4,313	-115,111	-643,428	68,390,302		65
16,876		-148,614	13,049,714		66
23,364	-28,746	-608,660	59,640,708		67
232,645	-11,577	-2,544,329	49,838,887		68
2,287	-14,053	-11,827	39,524,418		69
645,988	-39,355		10,147,983		70
812		-2,652	2,735,815		71
					72
2,588		-51,365	2,191,488		73
					74
1,483,352	-219,145	-6,027,506	473,031,177		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			6,083,452		86
735,462			82,205,652		87
555,376	-38,800		17,787,007		88
401,429	826,540		19,713,594		89
1,598			437,211		90
63,069	-842,390		3,489,659		91
24,516			792,562		92
			4,273,519		93
131,800	-3,930		7,278,057		94
			1,236,222		95
1,913,250	-58,580		143,296,935		96
			16,576,394		97
					98
1,913,250	-58,580		159,873,329		99
23,131,448	-277,725	-9,673,508	1,537,412,295		100
					101
					102
					103
23,131,448	-277,725	-9,673,508	1,537,412,295		104

Name of Respondent Black Hills Power, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report 2020/Q4

FOOTNOTE DATA

Schedule Page: 204 Line No.: 97 Column: g

This amount is related to our operating lease right-of-use assets as of December 31, 2020. Adoption of the new lease standard, ASU 2016-02, Leases (Topic 842), resulted in the recording of a operating lease right-of-use asset (account 101.1), corresponding amortization (account 108.2), and an off-setting operating lease obligation liability (accounts 227 and 243) effective January 1, 2019. The cumulative effect of the adoption did not materially impact results of operations. Adoption of the new standard had no impact on cash flows, rate base or cost of service rates.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
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32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Ben French Station - Land	Oct 2014	None Est	45,126
3	Neil Simpson Station I - Land	Oct 2014	None Est	1,000
4	Osage Plant - Land	Oct 2014	None Est	149,038
5	St Onge Plant - Land	Jul 2017	Jul 2022	254,255
6				
7	Other Property			
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Osage Plant - Water/Well Assets	Oct 2014	None Est	817,033
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			1,266,452

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Install 2nd Run of Mountain View	1,114,627
2	23565 Highway 385 Hwy, Rapid City	1,461,784
3	Whitewood to Nisland Convert Feeder	2,106,194
4	DISTRIBUTION PLANT LESS THAN $1,000,000 EACH	3,051,425
5		
6		
7	GENERAL PLANT-ELECTRIC LESS THAN $1,000,000 EACH	1,206,543
8		
9		
10	OTHER GENERATION -PLANT LESS THAN $1,000,000 EACH	1,217,986
11		
12		
13	NSC Security Improvements	1,150,946
14	Steam Plants DCS Loop Separation	1,170,567
15	BHP Share of Wyodak I Capital Costs	2,249,451
16	NS2 ACC Bundle Replacement	6,747,845
17	STEAM GENERATION LESS THAN $1,000,000 EACH	4,459,013
18		
19		
20	230kC Lange to West Rapid Rebuild	1,224,896
21	230kV Rebuilt Lange-Lookout	3,497,778
22	230kV Lange to South Rapid Rebuild	3,939,906
23	TRANSMISSION LESS THAN $1,000,000 EACH	1,283,037
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	35,881,998

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	443,772,946	443,772,946		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	39,159,974	39,159,974		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	611,207	611,207		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	2,471,920	2,471,920		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	42,243,101	42,243,101		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	24,016,284	24,016,284		
13	Cost of Removal	5,087,931	5,087,931		
14	Salvage (Credit)	58,169	58,169		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	29,046,046	29,046,046		
16	Other Debit or Cr. Items (Describe, details in footnote):	-10,401,988	-10,401,988		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	446,568,013	446,568,013		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	158,179,214	158,179,214		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	60,385,197	60,385,197		
25	Transmission	42,664,391	42,664,391		
26	Distribution	154,217,886	154,217,886		
27	Regional Transmission and Market Operation				
28	General	31,121,325	31,121,325		
29	TOTAL (Enter Total of lines 20 thru 28)	446,568,013	446,568,013		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) __ A Resubmission	04/16/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 219   Line No.: 16   Column: c

This amount is transfers during the year

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
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22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
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				40
				41
				42

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	2,150,484	1,041,059	Production
2	Fuel Stock Expenses Undistributed (Account 152)			Production
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	5,361,285	6,109,676	Trans & Dist
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	18,305,577	20,560,017	Production
8	Transmission Plant (Estimated)	27,318	20,816	Transmission
9	Distribution Plant (Estimated)	155,751	302,101	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	18,030	66,890	General
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	23,867,961	27,059,500	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	1,778,004	2,237,242	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	27,796,449	30,337,801	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) __ A Resubmission	04/16/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 227 Line No.: 11 Column: b

Operations and Maintenance expenses assigned to general.

Schedule Page: 227 Line No.: 11 Column: c

Operations and Maintenance expenses assigned to general.

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2021 No. (d)	2021 Amt. (e)
1	Balance-Beginning of Year	6,954.00		5,142.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	1,411.00		1,411.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	BH Gen Account to BHP	2,662.00			
10	BHP to BHC General Accout	-4,796.00		-322.00	
11					
12					
13					
14					
15	Total	-2,134.00		-322.00	
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20	Allowances Used	1,089.00		1,089.00	
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	5,142.00		5,142.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2022		2023		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
5,142.00		5,142.00		5,142.00		27,522.00		1
								2
								3
1,411.00		1,411.00		38,097.00		43,741.00		4
								5
								6
								7
								8
						2,662.00		9
-322.00		-322.00				-5,762.00		10
								11
								12
								13
								14
-322.00		-322.00				-3,100.00		15
								16
								17
								18
								19
1,089.00		1,089.00				4,356.00		20
								21
								22
								23
								24
								25
								26
								27
								28
5,142.00		5,142.00		43,239.00		63,807.00		29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent Black Hills Power, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report End of 2020/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2021 No. (d)	2021 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2022		2023		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
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20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
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49	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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21	**Generation Studies**				
22	Orion Renewable 3	68	561700		
23	Energy of Utah 80M	(376)	561700	75,612	561700
24	SD Sun Phase III			1,000	561700
25					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Deferred Taxes on AFUDC	4,927,401		283	277,699	4,649,702
2	Deferred Transmission Cost	5,008,929	21,561,763	Various	21,650,469	4,920,223
3	SD System Inspection	329,688		928	94,197	235,491
4	SD Storm Atlas	1,005,771		588	287,363	718,408
5	Rate Case Expenses	136,867		928	39,105	97,762
6	Power Plant Decommissioning Costs	6,210,526		405	1,774,436	4,436,090
7	Pension	20,116,920	114,405	228	1,303,533	18,927,792
8	Deferred Taxes on Flow Through Accounting	9,800,767	2,142,029			11,942,796
9	Defererred Power Cost Adjustment	11,709,438	61,362,315	Various	60,062,800	13,008,953
10	Retiree Healthcare Plan	445,212		Various	129,159	316,053
11	Energy Cost Adjustment	6,484,017	26,042,448	Various	25,936,951	6,589,514
12	Vegetation Management	8,062,306		Various	2,303,516	5,758,790
13	Energy Efficiency	371,363	1,177,355	Various	1,251,480	297,238
14						
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44	TOTAL	74,609,205	112,400,315		115,110,708	71,898,812

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) __ A Resubmission	04/16/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 232 Line No.: 3 Column: a

SD System Inspection will complete amortization in June 2023.

Approved by the South Dakota Public Utilities Commission in Docket EL14-026.

Schedule Page: 232 Line No.: 4 Column: a

SD Storm Atlas will complete amortization in June 2023.

Approved by the South Dakota Public Utilities Commission in Docket EL14-026.

Schedule Page: 232 Line No.: 5 Column: a

Rate Case Expenses will complete amortization in June 2023.

Approved by the South Dakota Public Utilities Commission in Docket EL14-026.

Schedule Page: 232 Line No.: 6 Column: a

Power Plant Decommissioning will complete amortization in June 2023.

Approved by the South Dakota Public Utilities Commission in Docket EL14-026.

Schedule Page: 232 Line No.: 12 Column: a

Approved by the South Dakota Public Utilities Commission in Docket EL14-026.

Vegetation Management will complete amortization in June 2023.

Name of Respondent Black Hills Power, Inc	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report End of 2020/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Deferred Assets Other	4,175,066	418,164	548	1,957	4,591,273
2	Deferred Rent	15,980	182	454	2,891	13,271
3	Misc Deferred Debits		738,116	921	621,852	116,264
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47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	4,191,046				4,720,808

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) __ A Resubmission	04/16/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 233 Line No.: 1 Column: c

Tax-Increment Financing for Horizon Point	216,561
Spare parts for Corriedale wind farm	201,603
Total	418,164

Schedule Page: 233 Line No.: 3 Column: f

116,264 ending balance related to IRP consulting fees.

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Deferred Compensation	141,599	139,245
3	Retiree Healthcare Plan	1,438,740	1,413,726
4	Regulatory Liabilities	20,627,867	20,012,149
5	Pension	5,347,536	5,031,438
6	Bad Debt Reserve	700,221	927,942
7	Other	6,417,424	10,458,194
8	TOTAL Electric (Enter Total of lines 2 thru 7)	34,673,387	37,982,694
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	34,673,387	37,982,694

Notes

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) __ A Resubmission	04/16/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 234 Line No.: 7 Column: b

Non-qualified Pension	306,292
PEP AOCI	167,097
Line Extension Deposits	(77,029)
Abandonment Loss	1,137,626
Other	1,587,481
Bonus Comp	272,288
Operating Lease	3,023,669
Total	6,417,424

Schedule Page: 234 Line No.: 7 Column: c

Non-qualified Pension Plan	281,952
PEP AOCI	180,237
Line Extension Deposits	1,613,683
Abandonment Loss	1,451,151
Other	3,076,838
Operating Lease	2,965,032
Production Tax Credit	583,418
Bonus Comp	305,883
Total	10,458,194

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock	50,000,000	1.00	
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CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
23,416,396	23,416,396					1
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OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
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40	TOTAL	

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock $1.00 Par Value	2,501,882
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22	TOTAL	2,501,882

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221		
2	Series:		
3	2014 AG 4.43%	85,000,000	716,799
4	2002 AE 7.23%	75,000,000	882,164
5	2009 AF 6.125%	180,000,000	2,277,473
6	SUBTOTAL	340,000,000	3,876,436
7			
8	ACCOUNT 224		
9	1994 A Environmental Improvement Bond (Variable)		69,943
10	Total	340,000,000	3,946,379
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33	TOTAL	340,000,000	3,946,379

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
10/01/2014	10/20/2044	10/01/2014	9/30/2044	85,000,000	3,765,500	3
8/13/2002	8/15/2032	8/13/2002	8/15/2032	75,000,000	5,422,500	4
10/27/2009	11/1/2039	10/27/2009	11/1/2039	180,000,000	11,025,000	5
				340,000,000	20,213,000	6
						7
						8
6/1/1994	6/1/2024	6/1/2024	6/1/2024		9,493	9
				340,000,000	20,222,493	10
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				340,000,000	20,222,493	33

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) __ A Resubmission	04/16/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 256 Line No.: 9 Column: a

1994 A Gillette Enviornmental Improvement Bond was paid off March, 24 2020. Therefore, unamortized DFC expense was fully expensed in 2020.

	Unamortized Loss on Reacquired Debt Acct# 189000
2004 Campbell County Pollution Control Bonds	139,700
Series 1984 Bond	28,466
1994 Gillette Bonds Bond	87,121
AB Bond	428,371
Z Bond	35,345
Total	719,003

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	53,936,910
2		
3		
4	Taxable Income Not Reported on Books	
5	Amortization of loss from interest rate swap	64,332
6	Prior Year Net Income already captured	256,513
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Nondeductible Federal Income Taxes	5,341,692
11	Deferred Revenue	3,140,172
12	Book Depreciation in Excess of Tax Depreciation	-3,633,233
13	Other	2,477,662
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	Operating Lease	-8,539
21	Rate Refund	-3,018,138
22	Derivative	-254,090
23	Employee Benefits	-846,407
24		
25		
26		
27	Federal Tax Net Income	57,456,875
28	Show Computation of Tax:	12,065,944
29		
30	Tax Return True Up Adjustment	72,117
31	FAS 109	-4,755,845
32		
33	Total	7,382,216
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) __ A Resubmission	04/16/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 261 Line No.: 13 Column: b

Meals and Entertainment	153,070
Club Dues	41,268
Lobbying	12,073
Captive Insurance	389,717
Reg Power Plant Maint	434,448
Fines and Penalties	805
Bad Debt Reserve	1,059,477
Required Bind Loss	269,788
Misc	11
Prepaid Expenses	61,170
PUC Fees	55,835
Total	2,477,662

Schedule Page: 261 Line No.: 22 Column: b

Insurance Reserve	(110,000)
Mark-to-market gain on derivative asset	(144,090)
Total	(254,090)

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal					
2						
3	Unemployment	168		19,723	9,875	
4	FICA	178,274		1,765,204	1,743,234	
5	Income	1,946,231		7,352,228	9,298,459	
6	Subtotal	2,124,673		9,137,155	11,051,568	
7						
8	State					
9	MT State Income					
10	SD Unemployment					
11	WY Unemployment	120		21,048	17,313	
12	Subtotal	120		21,048	17,313	
13						
14	Property Taxes					
15	SD	5,391,975		5,403,890	5,147,955	
16	WY	1,065,606		2,695,501	2,588,323	
17	MT	194,776		538,034	507,759	
18	NE	32,965		200,415	55,453	
19	Subtotal	6,685,322		8,837,840	8,299,490	
20						
21	MT Reg Tax			76,672	76,672	
22	Accrued Utility SD					
23	Accrued Taxes Sales/Use-SD	240,974		415,926	557,878	
24	Accrued Taxes WY	37,485		81,785	104,890	
25	Accrued Franchise Tax			64,495	64,495	
26	Subtotal	278,459		638,878	803,935	
27						
28						
29						
30						
31						
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35						
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37						
38						
39						
40						
41	TOTAL	9,088,574		18,634,921	20,172,306	

Name of Respondent Black Hills Power, Inc	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report End of 2020/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
						2
10,016		31,979				3
200,244		1,841,620				4
		7,309,643			42,586	5
210,260		9,183,242			42,586	6
						7
						8
						9
						10
3,855		56,843				11
3,855		56,843				12
						13
						14
5,647,910		5,403,890				15
1,172,784		2,695,501				16
225,051		538,034				17
177,927		200,415				18
7,223,672		8,837,840				19
						20
		76,672				21
						22
99,022		-22,068			437,994	23
14,380		-6,586			88,371	24
		64,495				25
113,402		112,513			526,365	26
						27
						28
						29
						30
						31
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						40
7,551,189		18,190,438			568,951	41

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) __ A Resubmission	04/16/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 262 Line No.: 5 Column: l

Non-operating current federal expense

Schedule Page: 262 Line No.: 23 Column: l

Sales tax capitalized or expensed

Schedule Page: 262 Line No.: 24 Column: l

Sales tax capitalized or expensed

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6							
7							
8	TOTAL						
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
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48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
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			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Contractor Retainage	2,112,140	253	18,554,966	18,384,222	1,941,396
2	Deferred Revenue	442,946	Various	2,787,618	2,345,812	1,140
3	Other	66,572	242	164,456	162,447	64,563
4						
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46						
47	TOTAL	2,621,658		21,507,040	20,892,481	2,007,099

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
							4
							5
							6
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							10
							11
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							20
							21

NOTES (Continued)

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	134,703,790	13,099,394	12,541,148
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	134,703,790	13,099,394	12,541,148
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	134,703,790	13,099,394	12,541,148
10	Classification of TOTAL			
11	Federal Income Tax	134,703,790	13,099,394	12,541,148
12	State Income Tax			
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
		182.3	223,223	182.3	3,841	135,042,654	2
							3
							4
			223,223		3,841	135,042,654	5
							6
							7
							8
			223,223		3,841	135,042,654	9
							10
			223,223		3,841	135,042,654	11
							12
							13

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) __ A Resubmission	04/16/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 274 Line No.: 2 Column: h

AFUDC Equity

Schedule Page: 274 Line No.: 2 Column: j

AFUDC Equity

Name of Respondent Black Hills Power, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report End of 2020/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Pension/Benefit	2,729,138	305,476	158,544
4	Reacquired Bond Loss	207,648		56,655
5	Equity AFUDC	1,034,753		
6	Derivative		364,325	347,576
7	Deferred Costs	8,264,171	1,958,746	2,299,511
8	Other	3,501,102	122,298	109,414
9	TOTAL Electric (Total of lines 3 thru 8)	15,736,812	2,750,845	2,971,700
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18				
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	15,736,812	2,750,845	2,971,700
20	Classification of TOTAL			
21	Federal Income Tax	15,736,813	2,750,845	2,971,700
22	State Income Tax			
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						2,876,070	3
		282	59,338		2,509,009	2,600,664	4
				219	13,510	1,048,263	5
						16,749	6
						7,923,406	7
				190	3,958	3,517,944	8
			59,338		2,526,477	17,983,096	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
			59,338		2,526,477	17,983,096	19
							20
			59,338		2,526,476	17,983,096	21
							22
							23

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) _ A Resubmission	04/16/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 276 Line No.: 8 Column: b

Goodwill	262,782
Operating Lease Asset	3,021,934
Prepaid Expenses	220,344
State NOL	(3,958)
Total	3,501,102

Schedule Page: 276 Line No.: 8 Column: c

Partnerships	9,607
Prepaid Expenses	112,691
Total	122,298

Schedule Page: 276 Line No.: 8 Column: d

Goodwill	39,336
Operating Lease Asset	57,221
Prepaid Expenses	12,846
State Income Tax Deduction	11
Total	109,414

Schedule Page: 276 Line No.: 8 Column: j

State NOL

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Reg Liability - Power Plant Maintenance	440,324			434,448	874,772
2	Reg Liability - Flowback Excess Deferred Taxes	99,745,026	Various	11,427,126	6,791,164	95,109,064
3	Reg Liability - Pension	5,347,535	Various	316,097		5,031,438
4	Reg Liability - Retiree Healthcare Plan	1,674,846	228	485,883		1,188,963
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40						
41	TOTAL	107,207,731		12,229,106	7,225,612	102,204,237

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	74,423,927	72,949,946
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	89,660,514	92,457,061
5	Large (or Ind.) (See Instr. 4)	34,686,078	34,892,910
6	(444) Public Street and Highway Lighting	1,243,730	1,272,995
7	(445) Other Sales to Public Authorities	2,110,574	1,975,010
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	202,124,823	203,547,922
11	(447) Sales for Resale	47,490,484	47,391,335
12	TOTAL Sales of Electricity	249,615,307	250,939,257
13	(Less) (449.1) Provision for Rate Refunds	-868,652	1,494,146
14	TOTAL Revenues Net of Prov. for Refunds	250,483,959	249,445,111
15	Other Operating Revenues		
16	(450) Forfeited Discounts	204,208	268,143
17	(451) Miscellaneous Service Revenues	458,043	514,949
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	17,422,342	16,993,574
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	628,934	677,328
22	(456.1) Revenues from Transmission of Electricity of Others	34,170,135	34,611,623
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	52,883,662	53,065,617
27	TOTAL Electric Operating Revenues	303,367,621	302,510,728

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
557,471	555,520	59,535	59,166	2
				3
732,595	766,056	13,544	13,532	4
443,403	457,413	25	24	5
10,239	10,409	214	213	6
21,549	20,006	149	149	7
				8
				9
1,765,257	1,809,404	73,467	73,084	10
1,311,985	1,327,436	40	48	11
3,077,242	3,136,840	73,507	73,132	12
				13
3,077,242	3,136,840	73,507	73,132	14

Line 12, column (b) includes $ 231,810 of unbilled revenues.

Line 12, column (d) includes 1,373 MWH relating to unbilled revenues

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
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2					
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38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RESIDENTIAL					
2	Regular Service - SD710	357,677	46,206,653	45,121	7,927	0.1292
3	Regular Service - SD875	405	54,250	39	10,385	0.1340
4	Regular Service - WY910	13,920	1,795,250	1,532	9,086	0.1290
5	Regular Service - MT910	73	5,420	12	6,083	0.0742
6	All Electric - SD712	93,346	9,697,757	7,340	12,717	0.1039
7	All Electric - SD876	98	11,624	9	10,889	0.1186
8	All Electric - SD887	208	22,449	10	20,800	0.1079
9	All Electric - WY912	4,035	495,542	335	12,045	0.1228
10	All Electric - WY913	20	2,285	1	20,000	0.1143
11	All Electric - MT912	31	1,663	1	31,000	0.0536
12	Demand Service - SD714	16,824	1,700,978	874	19,249	0.1011
13	Demand Service - SD716	67,340	6,148,391	3,106	21,681	0.0913
14	Demand Service - WY914	207	26,591	11	18,818	0.1285
15	Demand Service - WY916	1,542	186,258	84	18,357	0.1208
16	Utility Controlled - SD717	126	8,180	3	42,000	0.0649
17	Rental - SD798					
18	Rental - SD799		1,901	32		
19	Rental - WY798		130	2		
20	Private Area Lighting - SDA24	781	118,856	954	819	0.1522
21	Private Area Lighting - SDB24	18	3,882	8	2,250	0.2157
22	Private Area Lighting - SDC24	1	95	2	500	0.0950
23	Private Area Lighting - WYA24	45	8,667	59	763	0.1926
24	Private Area Lighting - WYB24					
25	PGM		34,172			
26	Unbilled	774	108,768			0.1405
27	Fuel Clause Accrual		7,784,165			
28	Total Residential	557,471	74,423,927	59,535	9,364	0.1335
29						
30	COMMERCIAL					
31	General Service - SD718	611	66,859	45	13,578	0.1094
32	General Service - SD720	335,962	42,794,749	10,341	32,488	0.1274
33	General Service - SD770	1,380	222,599	118	11,695	0.1613
34	General Service - SD826	10,461	1,046,216	31	337,452	0.1000
35	General Service - SD878	567	77,064	12	47,250	0.1359
36	General Service - SD890	204	31,309	1	204,000	0.1535
37	General Service - WY918	31	4,047	3	10,333	0.1305
38	General Service - WY920	20,662	2,665,126	470	43,962	0.1290
39	General Service - MT920	142	17,849	22	6,455	0.1257
40	All Electric - SD723	33,627	3,734,611	801	41,981	0.1111
41	TOTAL Billed	1,763,884	201,893,013	73,467	24,009	0.1145
42	Total Unbilled Rev.(See Instr. 6)	1,373	231,810	0	0	0.1688
43	TOTAL	1,765,257	202,124,823	73,467	24,028	0.1145

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	All Electric - WY923	1,075	126,097	38	28,289	0.1173
2	All Electric - MT923	11	840	2	5,500	0.0764
3	General Service Large - SD721	82,652	8,039,795	88	939,227	0.0973
4	General Service Large - SD771	26,668	1,745,728	1	26,668,000	0.0655
5	General Service Large - SD731	34,239	2,581,217	5	6,847,800	0.0754
6	General Service Large - SD827	168,777	14,316,963	108	1,562,750	0.0848
7	General Service Large - WY921	2,867	324,051	4	716,750	0.1130
8	Large DMD Curtailable - SD722	630	47,728	1	630,000	0.0758
9	Energy Storage - SD755	7,745	579,137	24	322,708	0.0748
10	Irrigation Pumping - SD726	802	112,142	24	33,417	0.1398
11	Utility Controlled - SD727	1,969	134,288	13	151,462	0.0682
12	Utility Controlled - SD750	199	17,290	2	99,500	0.0869
13	Rental - SD798		2,653	5		
14	Rental - SD799		26,907	186		
15	Rental - WY798		989	12		
16	Private Area Lighting - SDA24	1,826	247,958	936	1,951	0.1358
17	Private Area Lighting - SDB24	625	120,686	174	3,592	0.1931
18	Private Area Lighting - SDC24	128	9,291	16	8,000	0.0726
19	Private Area Lighting - WYA24	67	13,439	48	1,396	0.2006
20	Private Area Lighting - WYB24	44	10,233	13	3,385	0.2326
21	PGM		208,780			
22	Unbilled	-1,376	-102,308			0.0744
23	Fuel Clause Accrual		10,160,190			
24	Renewable Ready		275,991			
25	Total Commercial	732,595	89,660,514	13,544	54,090	0.1224
26						
27	INDUSTRIAL					
28	General Service Large - SD720	213	23,267	1	213,000	0.1092
29	General Service Large - SD721					
30	General Service Large - WY921	6,422	802,409	1	6,422,000	0.1249
31	General Service Large - WY934	48,020	4,611,510	7	6,860,000	0.0960
32	General Service Large - MT920	9	1,005	3	3,000	0.1117
33	General Service Large - MT930	3,225	438,367	1	3,225,000	0.1359
34	General Service Large - MT931	10,527	992,133	2	5,263,500	0.0942
35	General Service Large - MT932	132,385	8,176,049	1	132,385,000	0.0618
36	Large DMD Curtailable - N/A					
37	Industrial Contract Tran - SD761	95,191	5,628,594	1	95,191,000	0.0591
38	Industrial Contract Serv - WY931	53,561	4,026,782	1	53,561,000	0.0752
39	Forest Products Primary - SD764	28,267	2,020,464	1	28,267,000	0.0715
40	Forest Products Primary - SD774	52,436	3,322,646	1	52,436,000	0.0634
41	TOTAL Billed	1,763,884	201,893,013	73,467	24,009	0.1145
42	Total Unbilled Rev.(See Instr. 6)	1,373	231,810	0	0	0.1688
43	TOTAL	1,765,257	202,124,823	73,467	24,028	0.1145

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Forest Products Secondary - SD765	10,889	880,333	1	10,889,000	0.0808
2	Rental - SD798					
3	Rental - SD799					
4	Rental - WY798		308	1		
5	Private Area Lighting - SDA24	3	378	1	3,000	0.1260
6	Private Area Lighting - SDB24	2	495	1	2,000	0.2475
7	Private Area Lighting - SDC24					
8	Private Area Lighting - WYA24					
9	Private Area Lighting - WYB24	11	2,729	1	11,000	0.2481
10	Unbilled	2,242	245,401			0.1095
11	Fuel Clause Accrual		3,244,001			
12	Renewable Ready		269,207			
13	Total Industrial	443,403	34,686,078	25	17,736,120	0.0782
14						
15	PUBLIC STREET LIGHTING					
16	Company Owned Service - SD840	2,860	605,182	32	89,375	0.2116
17	Company Owned Service - WY940	250	70,388	1	250,000	0.2816
18	Customer Owned Service - SD741	6,177	448,572	32	193,031	0.0726
19	Customer Owned Service - SD841	109	11,059	5	21,800	0.1015
20	Customer Owned Service - WY941	107	8,382	1	107,000	0.0783
21	Traffic Signals - SD742	713	80,010	125	5,704	0.1122
22	Traffic Signals - WY942	9	1,873	3	3,000	0.2081
23	Rental - SD798		240	1		
24	Rental - SD799		16,292	7		
25	Private Area Lighting - SDA24	5	778	4	1,250	0.1556
26	Private Area Lighting - SDB24	1	271	1	1,000	0.2710
27	Private Area Lighting - SDC24	8	683	2	4,000	0.0854
28	Total Public Street Lighting	10,239	1,243,730	214	47,846	0.1215
29						
30	OTHER SALES TO PUBLIC AUTH					
31	Municipal Pumping - SD720	751	109,533	44	17,068	0.1458
32	Municipal Pumping - SD723	21	2,472	2	10,500	0.1177
33	Municipal Pumping - SD743	20,332	1,736,921	93	218,624	0.0854
34	Municipal Pumping - SD726	26	4,131	1	26,000	0.1589
35	Municipal Pumping - WY943	686	74,571	9	76,222	0.1087
36	Unbilled	-267	-20,051			0.0751
37	Fuel Clause Accrual		199,250			
38	Renewable Ready		3,747			
39	Total Other Sales	21,549	2,110,574	149	144,624	0.0979
40						
41	TOTAL Billed	1,763,884	201,893,013	73,467	24,009	0.1145
42	Total Unbilled Rev.(See Instr. 6)	1,373	231,810	0	0	0.1688
43	TOTAL	1,765,257	202,124,823	73,467	24,028	0.1145

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	City of Gillette	RQ	34	23	23	23
2	Montana Dakota Utilities	RQ	3	47	47	47
3	Municipal Energy Agency of Nebraska	LU	3			
4	PaficiCorp	OS	3			
5	The Energy Authority (MEAN)	OS	3			
6	WAPA Loveland	OS	3			
7	WAPA Colorado River Storage	OS	3			
8	Avista	OS	3			
9	Arizona Electric Power Coop	OS	3			
10	Avangrid Renewables	OS	3			
11	Basin Electric Power	OS	3			
12	City of Burbank	OS	3			
13	Black Hills Wyoming	OS	3			
14	Cheyenne Light, Fuel & Power	OS	3			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Citigroup	OS	3			
2	Colorado Springs Utilities	OS	3			
3	Constellation Energy	OS	3			
4	Coral Power	OS	3			
5	Eagle Energy	OS	3			
6	Guzmon Electric	OS	3			
7	Guzmon Renewables	OS	3			
8	Macquarie Energy	OS	3			
9	Nevada Power	OS	3			
10	Northwestern Energy	OS	3			
11	Platte River	OS	3			
12	Portland General Electric	OS	3			
13	Public Service Company of Colorado	OS	3			
14	Public Service Company of New Mexico	OS	3			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
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LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Puget Sound Energy	OS	3			
2	Southwest Power Pool	OS	3			
3	The Energy Authority	OS	3			
4	Tenaska	OS	3			
5	TransAlta Energy	OS	3			
6	Tri State Generation	OS	3			
7	Tucson Electric	OS	3			
8	Unisource	OS	3			
9	Utah Assoc Muni Power	OS	3			
10	Utah Municipal Power	OS	3			
11	WACM	OS	3			
12	WACMM1	OS	3			
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
15,718		353,727		353,727	1
88,787	2,240,494	2,694,113	1,511,783	6,446,390	2
123,487		6,049,628		6,049,628	3
5,378		201,595		201,595	4
846	32,131			32,131	5
27,909		1,214,155		1,214,155	6
19,935		1,159,599		1,159,599	7
450		13,100		13,100	8
215		13,155		13,155	9
-25		-450		-450	10
5,846		213,129		213,129	11
95		1,410		1,410	12
101		3,057		3,057	13
166,426		4,127,910	21,574	4,149,484	14
104,505	2,240,494	3,047,840	1,511,783	6,800,117	
1,207,480	32,131	40,636,662	21,574	40,690,367	
1,311,985	**2,272,625**	**43,684,502**	**1,533,357**	**47,490,484**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
224,320		7,077,340		7,077,340	1
25		440		440	2
624		9,484		9,484	3
525		14,450		14,450	4
1,273		34,858		34,858	5
16,653		445,144		445,144	6
2,024		63,663		63,663	7
512,757		16,914,850		16,914,850	8
190		14,050		14,050	9
1,680		49,305		49,305	10
6,306		263,203		263,203	11
50		2,000		2,000	12
4,014		225,380		225,380	13
12,191		499,050		499,050	14
104,505	2,240,494	3,047,840	1,511,783	6,800,117	
1,207,480	32,131	40,636,662	21,574	40,690,367	
1,311,985	**2,272,625**	**43,684,502**	**1,533,357**	**47,490,484**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
1,400		57,775		57,775	1
4,249		74,084		74,084	2
369		13,707		13,707	3
80		3,390		3,390	4
1,553		65,051		65,051	5
593		15,825		15,825	6
44,283		1,014,900		1,014,900	7
175		5,425		5,425	8
6,000		206,800		206,800	9
13,743		491,685		491,685	10
223		11,035		11,035	11
1,517		67,480		67,480	12
					13
					14
104,505	2,240,494	3,047,840	1,511,783	6,800,117	
1,207,480	32,131	40,636,662	21,574	40,690,367	
1,311,985	**2,272,625**	**43,684,502**	**1,533,357**	**47,490,484**	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) _ A Resubmission	04/16/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 310 Line No.: 2 Column: j

Other Charges - Expense Reimbursements

Schedule Page: 310 Line No.: 13 Column: a

Affiliate of Black Hills Power

Schedule Page: 310 Line No.: 14 Column: a

Affiliate of Black Hills Power

Schedule Page: 310 Line No.: 14 Column: j

Other Charges - Expenses Reimbursements

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,124,715	1,280,854
5	(501) Fuel	19,711,385	19,819,274
6	(502) Steam Expenses	1,589,496	1,627,234
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	589,210	664,609
10	(506) Miscellaneous Steam Power Expenses	1,406,798	1,666,930
11	(507) Rents	2,660,405	2,525,546
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	27,082,009	27,584,447
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	813,890	1,518,199
16	(511) Maintenance of Structures	558,126	842,968
17	(512) Maintenance of Boiler Plant	4,980,274	4,407,018
18	(513) Maintenance of Electric Plant	974,944	911,548
19	(514) Maintenance of Miscellaneous Steam Plant	54,929	56,417
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	7,382,163	7,736,150
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	34,464,172	35,320,597
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	951,066	1,044,045
63	(547) Fuel	6,589,513	6,430,427
64	(548) Generation Expenses	90,369	114,334
65	(549) Miscellaneous Other Power Generation Expenses	444,345	361,117
66	(550) Rents	295,426	269,310
67	TOTAL Operation (Enter Total of lines 62 thru 66)	8,370,719	8,219,233
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	2,899	22,481
70	(552) Maintenance of Structures	6,941	25,917
71	(553) Maintenance of Generating and Electric Plant	2,159,703	2,394,349
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	57,174	37,972
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	2,226,717	2,480,719
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	10,597,436	10,699,952
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	36,404,022	37,066,951
77	(556) System Control and Load Dispatching	1,148,415	1,497,882
78	(557) Other Expenses	255	
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	37,552,692	38,564,833
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	82,614,300	84,585,382
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,029,086	993,575
84			
85	(561.1) Load Dispatch-Reliability	162,681	75,329
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	663,072	801,658
87	(561.3) Load Dispatch-Transmission Service and Scheduling	236,767	218,417
88	(561.4) Scheduling, System Control and Dispatch Services	287,696	316,188
89	(561.5) Reliability, Planning and Standards Development	742,738	965,028
90	(561.6) Transmission Service Studies	78,512	1,492
91	(561.7) Generation Interconnection Studies	-76,296	54,824
92	(561.8) Reliability, Planning and Standards Development Services	84,140	295,871
93	(562) Station Expenses	403,419	424,269
94	(563) Overhead Lines Expenses	65,866	319,911
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	22,919,417	23,638,278
97	(566) Miscellaneous Transmission Expenses	513,363	274,258
98	(567) Rents	40,786	23,307
99	TOTAL Operation (Enter Total of lines 83 thru 98)	27,151,247	28,402,405
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	3,217	
102	(569) Maintenance of Structures	30,037	4,730
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	159,723	212,826
108	(571) Maintenance of Overhead Lines	588,760	669,414
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	79	16,561
111	TOTAL Maintenance (Total of lines 101 thru 110)	781,816	903,531
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	27,933,063	29,305,936

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,426,449	1,733,121
135	(581) Load Dispatching	482,034	423,876
136	(582) Station Expenses	606,486	617,432
137	(583) Overhead Line Expenses	348,552	579,538
138	(584) Underground Line Expenses	428,639	433,067
139	(585) Street Lighting and Signal System Expenses	66,886	88,096
140	(586) Meter Expenses	504,834	633,367
141	(587) Customer Installations Expenses	360,702	312,926
142	(588) Miscellaneous Expenses	1,537,345	2,147,665
143	(589) Rents	-27,431	51,357
144	TOTAL Operation (Enter Total of lines 134 thru 143)	5,734,496	7,020,445
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	34,097	41,389
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	157,059	171,481
149	(593) Maintenance of Overhead Lines	8,429,688	8,814,037
150	(594) Maintenance of Underground Lines	501,268	533,308
151	(595) Maintenance of Line Transformers	47,605	70,087
152	(596) Maintenance of Street Lighting and Signal Systems	85,290	56,742
153	(597) Maintenance of Meters	176,417	75,808
154	(598) Maintenance of Miscellaneous Distribution Plant	60,872	85,531
155	TOTAL Maintenance (Total of lines 146 thru 154)	9,492,296	9,848,383
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	15,226,792	16,868,828
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	61,736	70,895
160	(902) Meter Reading Expenses	132,261	20,056
161	(903) Customer Records and Collection Expenses	1,289,253	1,573,206
162	(904) Uncollectible Accounts	691,929	608,531
163	(905) Miscellaneous Customer Accounts Expenses	293,582	282,337
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	2,468,761	2,555,025

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	29,638	32,047
168	(908) Customer Assistance Expenses	403,310	442,522
169	(909) Informational and Instructional Expenses	22,016	9,674
170	(910) Miscellaneous Customer Service and Informational Expenses	19,067	51,889
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	474,031	536,132
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		138
175	(912) Demonstrating and Selling Expenses	48,491	1,159
176	(913) Advertising Expenses	28,054	2,141
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	76,545	3,438
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	13,838,061	15,222,805
182	(921) Office Supplies and Expenses	4,106,609	4,346,787
183	(Less) (922) Administrative Expenses Transferred-Credit	2,850,848	2,959,147
184	(923) Outside Services Employed	4,566,265	4,026,888
185	(924) Property Insurance	780,369	591,919
186	(925) Injuries and Damages	1,510,707	1,601,542
187	(926) Employee Pensions and Benefits	6,759,753	2,876,930
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	988,759	770,070
190	(929) (Less) Duplicate Charges-Cr.	228,286	237,828
191	(930.1) General Advertising Expenses	491,055	481,258
192	(930.2) Miscellaneous General Expenses	1,063,972	1,723,140
193	(931) Rents	1,756,493	2,705,666
194	TOTAL Operation (Enter Total of lines 181 thru 193)	32,782,909	31,150,030
195	Maintenance		
196	(935) Maintenance of General Plant	2,204,077	2,063,087
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	34,986,986	33,213,117
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	163,780,478	167,067,858

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Pacificorp Colstrip	LF	236	50	50	46
2	Pacificorp	OS	181			
3	Arizona Electric Powe Coop	OS				
4	Avangrid Renewables	OS				
5	Avista Water Power	OS				
6	Basin Electric	OS				
7	Black Hills Wyoming	OS				
8	Cheyenne Light,Fuel & Power	OS				
9	Cheyenne Light, Fuel & Power	OS				
10	Colorado Springs Utilities	OS				
11	Corriedale Wind	OS				
12	Constellation Power	OS				
13	Coral Power	OS				
14	City of Gillette	OS				
	Total					

Name of Respondent Black Hills Power, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report End of 2020/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Eagle Energy	OS				
2	Energy Keepers	OS				
3	Guzman Energy	OS				
4	Guzman Renewables	OS				
5	Idaho Power	OS				
6	Macquarie Energy	OS				
7	Morgan Stanley Capital Group	OS				
8	Municipal Energy Agency of Nebraska	OS				
9	Northwestern Energy	OS				
10	Platte River Power Authority	OS				
11	Platte River Power Authority-SS Wind	OS				
12	Portland General Electric Company	OS				
13	Public Service Company of New Mexico	OS				
14	Puget Sound Energy	OS				
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Rainbow Energy Marketing	OS				
2	Seattle City Light	AD				
3	Southwest Power Pool	OS				
4	City of Spearfish	OS				
5	Tacoma Power	OS				
6	The Energy Authority	OS				
7	The Energy Authority	OS				
8	Tenaska Power	OS				
9	TransAlta Energy	OS				
10	Tri State Generation and Transmission	OS				
11	Tucson Electric	OS				
12	Westar	OS				
13	Western Area Power Administration	OS				
14	Western Area Power Administration	OS				
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Western Area Power Administration	OS				
2	Western Area Power Administration	OS				
3	Public Service Company of Colorado	OS				
4	Western Area Power Administration	EX				
5	Duke Energy	EX				
6	Renewable Energy Rate 44	OS				
7	WACM-NWPP	OS				
8						
9						
10						
11						
12						
13						
14						
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
256,332				448,909	5,452,692	5,901,601	1
25,428							2
				8,112		8,112	3
939			946,080	11,065		957,145	4
6,352				97,950		97,950	5
83,584				1,680,210		1,680,210	6
				-2,892		-2,892	7
60,713				1,633,887		1,633,887	8
112,210				6,401,344		6,401,344	9
942				12,122	1,200	13,322	10
23,524				698,358		698,358	11
624				8,712		8,712	12
2,279				16,079		16,079	13
				-2,370		-2,370	14
1,337,125	3,759	72,222	946,080	29,655,441	5,802,501	36,404,022	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
13,526				395,106		395,106	1
7,824				621,056		621,056	2
1,922				23,033		23,033	3
2,739				37,774		37,774	4
6,004				56,162		56,162	5
523,736				13,939,261		13,939,261	6
75				6,250		6,250	7
22							8
5,536				63,459		63,459	9
3,575				60,287		60,287	10
35,769				715,372		715,372	11
2,133				302,629		302,629	12
23,848				205,983		205,983	13
830				47,495		47,495	14
1,337,125	3,759	72,222	946,080	29,655,441	5,802,501	36,404,022	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
8,296				118,089		118,089	1
3,575				49,500		49,500	2
18,000				18,256		18,256	3
25,019				781,003		781,003	4
447				2,792		2,792	5
1,388				47,403		47,403	6
11,504				179,065		179,065	7
50				810		810	8
16,335				321,405		321,405	9
6,260				207,118		207,118	10
701				51,947		51,947	11
77				1,574		1,574	12
371				-96,977	60,084	-36,893	13
10,347				41,033		41,033	14
1,337,125	3,759	72,222	946,080	29,655,441	5,802,501	36,404,022	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
5,604				98,317		98,317	1
11,633				-17,301		-17,301	2
16,547				344,383		344,383	3
	3,759	72,222			169,095	169,095	4
					119,430	119,430	5
				14,250		14,250	6
505				7,421		7,421	7
							8
							9
							10
							11
							12
							13
							14
1,337,125	3,759	72,222	946,080	29,655,441	5,802,501	36,404,022	

Name of Respondent Black Hills Power, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report 2020/Q4

FOOTNOTE DATA

Schedule Page: 326 Line No.: 1 Column: a
LF Coal Strip Contract - Termination date 12/31/2023
Schedule Page: 326 Line No.: 2 Column: b
OS Statistical classification is market based sales.
Schedule Page: 326 Line No.: 3 Column: b
OS Statistical classification is market based sales.
Schedule Page: 326 Line No.: 4 Column: b
OS Statistical classification is market based sales.
Schedule Page: 326 Line No.: 5 Column: b
OS Statistical classification is market based sales.
Schedule Page: 326 Line No.: 6 Column: b
OS Statistical classification is market based sales.
Schedule Page: 326 Line No.: 7 Column: b
OS Statistical classification is market based sales.
Schedule Page: 326 Line No.: 8 Column: b
OS Statistical classification is market based sales.
Schedule Page: 326 Line No.: 9 Column: b
OS Statistical classification is market based sales.
Schedule Page: 326 Line No.: 10 Column: b
OS Statistical classification is market based sales.
Schedule Page: 326 Line No.: 10 Column: l
Spinning Reserve
Schedule Page: 326 Line No.: 11 Column: a
Renewable Ready Credits authorized in docket Docket No. 20002-113-ET-19 by the Wyoming Public Service Commission and Docket No. EL18-060 by the South Dakota Public Utilities Commission.
Schedule Page: 326 Line No.: 11 Column: b
OS Statistical classification is market based sales.

Schedule Page: 326 Line No.: 12 Column: b
OS Statistical classification is market based sales.
Schedule Page: 326 Line No.: 13 Column: b
OS Statistical classification is market based sales.
Schedule Page: 326 Line No.: 14 Column: b
OS Statistical classification is market based sales.
Schedule Page: 326.1 Line No.: 1 Column: b
OS Statistical classification is market based sales.
Schedule Page: 326.1 Line No.: 2 Column: b
OS Statistical classification is market based sales.
Schedule Page: 326.1 Line No.: 3 Column: b
OS Statistical classification is market based sales.
Schedule Page: 326.1 Line No.: 4 Column: b
OS Statistical classification is market based sales.
Schedule Page: 326.1 Line No.: 5 Column: b
OS Statistical classification is market based sales.
Schedule Page: 326.1 Line No.: 6 Column: b
OS Statistical classification is market based sales.
Schedule Page: 326.1 Line No.: 7 Column: b
OS Statistical classification is market based sales.
Schedule Page: 326.1 Line No.: 8 Column: b
OS Statistical classification is market based sales.
Schedule Page: 326.1 Line No.: 9 Column: b
OS Statistical classification is market based sales.
Schedule Page: 326.1 Line No.: 10 Column: b

Name of Respondent Black Hills Power, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report 2020/Q4

FOOTNOTE DATA

OS Statistical classification is market based sales.

Schedule Page: 326.1 Line No.: 11 Column: b
OS Statistical classification is market based sales.

Schedule Page: 326.1 Line No.: 12 Column: b
OS Statistical classification is market based sales.

Schedule Page: 326.1 Line No.: 13 Column: b
OS Statistical classification is market based sales.

Schedule Page: 326.1 Line No.: 14 Column: b
OS Statistical classification is market based sales.

Schedule Page: 326.2 Line No.: 1 Column: b
OS Statistical classification is market based sales.

Schedule Page: 326.2 Line No.: 3 Column: b
OS Statistical classification is market based sales.

Schedule Page: 326.2 Line No.: 4 Column: b
OS Statistical classification is market based sales.

Schedule Page: 326.2 Line No.: 5 Column: b
OS Statistical classification is market based sales.

Schedule Page: 326.2 Line No.: 6 Column: b
OS Statistical classification is market based sales.

Schedule Page: 326.2 Line No.: 7 Column: b
OS Statistical classification is market based sales.

Schedule Page: 326.2 Line No.: 8 Column: b
OS Statistical classification is market based sales.

Schedule Page: 326.2 Line No.: 9 Column: b
OS Statistical classification is market based sales.

Schedule Page: 326.2 Line No.: 10 Column: b
OS Statistical classification is market based sales.

Schedule Page: 326.2 Line No.: 11 Column: b
OS Statistical classification is market based sales.

Schedule Page: 326.2 Line No.: 12 Column: b
OS Statistical classification is market based sales.

Schedule Page: 326.2 Line No.: 13 Column: a
Colorado River Storage Project

Schedule Page: 326.2 Line No.: 13 Column: b
OS Statistical classification is market based sales.

Schedule Page: 326.2 Line No.: 13 Column: l
Spinning Exchange

Schedule Page: 326.2 Line No.: 14 Column: a
Loveland Area Project

Schedule Page: 326.2 Line No.: 14 Column: b
OS Statistical classification is market based sales.

Schedule Page: 326.3 Line No.: 1 Column: a
Upper Great Plains Region

Schedule Page: 326.3 Line No.: 1 Column: b
OS Statistical classification is market based sales.

Schedule Page: 326.3 Line No.: 2 Column: a
WACM Loveland

Schedule Page: 326.3 Line No.: 2 Column: b
OS Statistical classification is market based sales.

Schedule Page: 326.3 Line No.: 3 Column: b
OS Statistical classification is market based sales.

Schedule Page: 326.3 Line No.: 4 Column: l
Deviation Power Exchange

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) __ A Resubmission	04/16/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 326.3 Line No.: 5 Column: l

Deviation Power Exchange

Schedule Page: 326.3 Line No.: 6 Column: a

Renewable energy customer purchase program

Schedule Page: 326.3 Line No.: 6 Column: b

OS Statistical classification is market based sales.

Schedule Page: 326.3 Line No.: 7 Column: b

OS Statistical classification is market based sales.

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi- cation (d)
1	State of South Dakota	Western Area Power Administration	Black Hills State University,	OS
2	Basin Electric Power	Basin Electric Power	Black Hills Power	OS
3	Powder River Energy	Powder River Energy	Powder River Energy	OS
4	Black Hills Power	Black Hills Power	Black Hills Power	FNS
5	Basin Electric Power	Basin Electric Power	Basin Electric Power	FNO
6	Cheyenne Light, Fuel & Power	Cheyenne Light, Fuel & Power	Cheyenne Light, Fuel & Power	FNO
7	City of Gillette	Black Hills Power	City of Gillette	FNO
8	State of South Dakota	Western Area Power Administration	State of South Dakota	FNO
9	Cheyenne Light, Fuel & Power	Black Hills Wyoming	Cheyenne Light, Fuel & Power	LFP
10	Municipal Energy Agency of Nebraska	Black Hills Power	MEAN,	LFP
11	Wyoming Municipal Power Agency	Wyoming Municipal Power Agency	Wyoming Municipal Power Agency	LFP
12	Basin Electric Power	Basin Electric Power	Basin Electric Power	LFP
13	Basin Electric Power	Basin Electric Power	Basin Electric Power	SFP
14	Basin Electric Power	Basin Electric Power	Basin Electric Power	LFP
15	Basin Electric Power	Basin Electric Power	Basin Electric Power	LFP
16	Basin Electric Power	Basin Electric Power	Basin Electric Power	LFP
17	Basin Electric Power	Basin Electric Power	Basin Electric Power	LFP
18	Basin Electric Power	Basin Electric Power	Basin Electric Power	LFP
19	Black Hills Wyoming	Black Hills Wyoming	Black Hills Power	LFP
20	Black Hills Power	Black Hills Power	Black Hills Power	LFP
21	Black Hills Power	Black Hills Power	Black Hills Power	LFP
22	Shell Energy North America	Shell Energy North America	Shell Energy North America	LFP
23	CP Energy Marketing	CP Energy Marketing	CP Energy Marketing	LFP
24	CP Energy Marketing	CP Energy Marketing	CP Energy Marketing	LFP
25	MAG Energy Solutions	MAG Energy Solutions	MAG Energy Solutions	LFP
26	Paficicorp	Paficicorp	Paficicorp	LFP
27	Paficicorp	Paficicorp	Paficicorp	LFP
28	Paficicorp	Paficicorp	Paficicorp	LFP
29	Rainbow Energy Marketing Corp	Rainbow Energy Marketing Corp	Rainbow Energy Marketing Corp	LFP
30	Rainbow Energy Marketing Corp	Rainbow Energy Marketing Corp	Rainbow Energy Marketing Corp	LFP
31	Rainbow Energy Marketing Corp	Rainbow Energy Marketing Corp	Rainbow Energy Marketing Corp	LFP
32	TransAlta Energy Marketing Corp	TransAlta Energy Marketing Corp	TransAlta Energy Marketing Corp	LFP
33	Basin Electric	Basin Electric	Basin Electric	NF
34	Basin Electric	Basin Electric	Basin Electric	NF
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Basin Electric	Basin Electric	Basin Electric	NF
2	Basin Electric	Basin Electric	Basin Electric	NF
3	Basin Electric	Basin Electric	Basin Electric	NF
4	Basin Electric	Basin Electric	Basin Electric	NF
5	Basin Electric	Basin Electric	Basin Electric	NF
6	Basin Electric	Basin Electric	Basin Electric	NF
7	Basin Electric	Basin Electric	Basin Electric	NF
8	Basin Electric	Basin Electric	Basin Electric	NF
9	Basin Electric	Basin Electric	Basin Electric	NF
10	Basin Electric	Basin Electric	Basin Electric	NF
11	Basin Electric	Basin Electric	Basin Electric	NF
12	Basin Electric	Basin Electric	Basin Electric	NF
13	Basin Electric	Basin Electric	Basin Electric	NF
14	Basin Electric	Basin Electric	Basin Electric	NF
15	Black Hills Colorado Electric	Black Hills Colorado Electric	Black Hills Colorado Electric	NF
16	Black Hills Colorado Electric	Black Hills Colorado Electric	Black Hills Colorado Electric	NF
17	Black Hills Colorado Electric	Black Hills Colorado Electric	Black Hills Colorado Electric	NF
18	Black Hills Colorado Electric	Black Hills Colorado Electric	Black Hills Colorado Electric	NF
19	Black Hills Colorado Electric	Black Hills Colorado Electric	Black Hills Colorado Electric	NF
20	Black Hills Colorado Electric	Black Hills Colorado Electric	Black Hills Colorado Electric	NF
21	Black Hills Colorado Electric	Black Hills Colorado Electric	Black Hills Colorado Electric	NF
22	Black Hills Wyoming	Black Hills Wyoming	Black Hills Power	NF
23	Black Hills Wyoming	Black Hills Wyoming	Black Hills Power	NF
24	Black Hills Wyoming	Black Hills Wyoming	Black Hills Power	NF
25	Black Hills Wyoming	Black Hills Wyoming	Black Hills Power	NF
26	Black Hills Wyoming	Black Hills Wyoming	Black Hills Power	NF
27	Black Hills Wyoming	Black Hills Wyoming	Black Hills Power	NF
28	Black Hills Wyoming	Black Hills Wyoming	Black Hills Power	NF
29	Black Hills Wyoming	Black Hills Wyoming	Black Hills Wyoming	NF
30	Black Hills Power	Pacificorp,	Black Hills Power	NF
31	Black Hills Power	BC Hydro	Cheyenne Light, Fuel & Power	NF
32	Black Hills Power	Pacificorp	Black Hills Power	NF
33	Black Hills Power	Basin Electric Power	Black Hills Power	NF
34	Black Hills Power	Basin Electric Power	Black Hills Power	NF
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Black Hills Power	Basin Electric Power	Black Hills Power	NF
2	Black Hills Power	Basin Electric Power	Black Hills Power	NF
3	Black Hills Power	Basin Electric Power	Black Hills Power	NF
4	Black Hills Power	Basin Electric Power	Black Hills Power	NF
5	Black Hills Power	Pacificorp	Black Hills Power ,	NF
6	Black Hills Power	Black Hills Power	Tristate,	NF
7	Black Hills Power	Black Hills Power	Western Area Power Authority,	NF
8	Black Hills Power	Basin Electric Power	Black Hills Power	NF
9	Black Hills Power	Black Hills Power	Basin Electric Power	NF
10	Black Hills Power	Black Hills Power	Basin Electric Power	NF
11	Black Hills Power	Basin Electric Power	Black Hills Power	NF
12	Black Hills Power	Black Hills Power	Western Area Power Administration	NF
13	Black Hills Power	Black Hills Power	Western Area Power Administration	NF
14	Black Hills Power	Black Hills Power	Black Hills Power	NF
15	Black Hills Power	Black Hills Power	Black Hills Power	NF
16	Black Hills Power	Black Hills Power	Black Hills Power	NF
17	Cheyenne Light, Fuel & Power	Black Hills Power	Black Hills Power	NF
18	Cheyenne Light, Fuel & Power	Black Hills Power	Black Hills Power	NF
19	Cheyenne Light, Fuel & Power	Black Hills Power	Black Hills Power	NF
20	Cheyenne Light, Fuel & Power	Pacificorp	Black Hills Power	NF
21	Cheyenne Light, Fuel & Power	Black Hills Power	Black Hills Power	NF
22	Cheyenne Light, Fuel & Power	Black Hills Power	Black Hills Power	NF
23	Shell Energy North America	Shell Energy North America	Shell Energy North America	NF
24	Shell Energy North America	Western Area Power Administration	Shell Energy North America	NF
25	Shell Energy North America	Western Area Power Administration	Shell Energy North America	NF
26	Shell Energy North America	Western Area Power Administration	Shell Energy North America	NF
27	Shell Energy North America	Western Area Power Administration	Shell Energy North America	NF
28	Shell Energy North America	Shell Energy North America	Shell Energy North America	NF
29	CP Energy Marketing	CP Energy Marketing	CP Energy Marketing	NF
30	MAG Energy Solutions	MAG Energy Solutions	MAG Energy Solutions	NF
31	MAG Energy Solutions	MAG Energy Solutions	MAG Energy Solutions	NF
32	MAG Energy Solutions	MAG Energy Solutions	MAG Energy Solutions	NF
33	Macquarie Energy	Macquarie Energy	Macquarie Energy	NF
34	Municipal Energy Agency of Nebraska	Black Hills Power	MEAN	NF
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Morgan Stanley Capital Group	Morgan Stanley Capital Group	Morgan Stanley Capital Group	NF
2	Paficicorp	Paficicorp	Black Hills Power,	NF
3	Powerex Corp	Powerex Corp	Powerex Corp	NF
4	Powerex Corp	Powerex Corp	Powerex Corp	NF
5	Powerex Corp	Powerex Corp	Powerex Corp	NF
6	Public Service Company of Colorado	Public Service Company of Colora	Public Service Company of Colora	NF
7	Rainbow energy Marketing Corporation	Rainbow energy Marketing Corpora	Rainbow energy Marketing Corpora	NF
8	Rainbow energy Marketing Corporation	Rainbow energy Marketing Corpora	Rainbow energy Marketing Corpora	NF
9	Rainbow energy Marketing Corporation	Rainbow energy Marketing Corpora	Rainbow energy Marketing Corpora	NF
10	Rainbow energy Marketing Corporation	Rainbow energy Marketing Corpora	Rainbow energy Marketing Corpora	NF
11	Rainbow energy Marketing Corporation	Rainbow energy Marketing Corpora	Rainbow energy Marketing Corpora	NF
12	The Energy Authority	The Energy Authority	The Energy Authority	NF
13	The Energy Authority	The Energy Authority	The Energy Authority	NF
14	TransAlta Energy Marketing	TransAlta Energy Marketing	TransAlta Energy Marketing	NF
15	TransAlta Energy Marketing	TransAlta Energy Marketing	TransAlta Energy Marketing	NF
16	TransAlta Energy Marketing	TransAlta Energy Marketing	TransAlta Energy Marketing	NF
17	Tenaska Power Services Co	Tenaska Power Services Co	Tenaska Power Services Co	NF
18	Tenaska Power Services Co	Tenaska Power Services Co	Tenaska Power Services Co	NF
19	Tenaska Power Services Co	Tenaska Power Services Co	Tenaska Power Services Co	NF
20	Westar Energy Generation & Marketing	Westar Energy Generation & Marke	Westar Energy Generation & Marke	NF
21	Westar Energy Generation & Marketing	Westar Energy Generation & Marke	Westar Energy Generation & Marke	NF
22	WestConnect	Black Hills Power	Black Hills Power	NF
23	WestConnect	Black Hills Power	Black Hills Power	NF
24	WestConnect	MAG Energy Solutions	MAG Energy Solutions	NF
25	WestConnect	MAG Energy Solutions	MAG Energy Solutions	NF
26	WestConnect	MAG Energy Solutions	MAG Energy Solutions	NF
27	WestConnect	Rainbow energy Marketing Corpora	Rainbow energy Marketing Corpora	NF
28	WestConnect	TransAlta Energy Marketing	TransAlta Energy Marketing	NF
29	WestConnect	Tenaska Power Services Co	Tenaska Power Services Co	NF
30	WestConnect	Tenaska Power Services Co	Tenaska Power Services Co	NF
31	WestConnect	Tenaska Power Services Co	Tenaska Power Services Co	NF
32				
33				
34				
	TOTAL			

Name of Respondent Black Hills Power, Inc	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report End of 2020/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Line No.
	Rapid City SD	SOUTH DAKOTA WEST		18,393	18,393	1
	RC DC TIE	RC DC		2,502	2,502	2
	WYODAK	UPTON BENTONITE		9,859	9,859	3
11	VARIOUS	VARIOUS		1,922,249	1,922,249	4
11	VARIOUS	VARIOUS		1,889,665	1,889,665	5
11	VARIOUS	VARIOUS		713,167	713,167	6
11	VARIOUS	VARIOUS		311,147	311,147	7
11	VARIOUS	VARIOUS		16,751	16,751	8
7	WYODAK	SGW	60	197,318	197,318	9
7	WYODAK, WY69	SGW	32	240,472	240,472	10
7	DRYFORK	DJ	30	194,487	194,487	11
7	DRYFORK	RC	130	109,156	109,156	12
7	RC	DJ		558	558	13
7	RC	SGW		358	358	14
7	DRYFORK	DJ		3,723	3,723	15
7	DRYFORK	SGW		660	660	16
7	DJ	WYODAK		15	15	17
7	WYODAK	DJ		202	202	18
7	WYODAK	DJ		25	25	19
7	DJ	RC		50	50	20
7	WYODAK	SGW		30	30	21
7	RC	DJ		232	232	22
7	RC	DJ		175	175	23
7	DJ	RC		4	4	24
7	RC	DJ		900	900	25
7	WYODAK	ANTELOPE		5,825	5,825	26
7	DJ	WYODAK		979	979	27
7	WYODAK	DJ		15,671	15,671	28
7	RC	DJ		60	60	29
7	WYODAK	DJ		54	54	30
7	RC	SGW		203	203	31
7	RC	DJ		316	316	32
7	RC	DJ		3,256	3,256	33
8	DJ	DRYFORK		2,942	2,942	34
			252	**6,011,541**	**6,011,541**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
8	DJ	SGW		5,994	5,994	1
8	DRYFORK	DJ		82,522	82,522	2
8	DRYFORK	RC		226	226	3
8	DRYFORK	SGW		33,415	33,415	4
8	DRYFORK	WYODAK		2,103	2,103	5
8	RC	DRYFORK		790	790	6
8	RC	SGW		75	75	7
8	RC	WSTAR		285	285	8
8	SGW	DRYFORK		4,583	4,583	9
8	SGW	WYODAK		4,285	4,285	10
8	WYODAK	WYODAK		150	150	11
8	DJ	WYODAK		2,713	2,713	12
8	WYODAK	DJ		84	84	13
8	RC	WYODAK		1,057	1,057	14
8	RC	DJ		795	795	15
8	WYODAK	SGW		200	200	16
8	ANTELOPE	DJ		15	15	17
8	SGW	RC		6	6	18
8	WYODAK	DJ		20	20	19
8	DRYFORK	DJ		93	93	20
8	SGW	DRYFORK		2	2	21
8	SGW	RC		150	150	22
8	DJ	RC		550	550	23
8	DJ	WYODAK		2,231	2,231	24
8	DRYFORK	RC		40	40	25
8	WYODAK	SGW		100	100	26
8	SGW	WYODAK		9	9	27
8	WYODAK	DJ		30,645	30,645	28
8	WYODAK	WYODAK		5	5	29
8	DJ	RC		12,725	12,725	30
8	DJ	SGW		277	277	31
8	DJ	WYODAK		5,143	5,143	32
8	DRYFORK	DJ		95	95	33
8	DRYFORK	RC		2,510	2,510	34
			252	**6,011,541**	**6,011,541**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Line No.
8	ANTELOPE	RC		125	125	1
8	RC	DJ		532	532	2
8	RC	SGW		495	495	3
8	SGW	RC		1,212	1,212	4
8	SGW	WYODAK		293	293	5
8	RC	DRYFORK		73	73	6
8	ANTELOPE	WYODAK		790	790	7
8	WYODAK	ANTELOPE		17	17	8
8	WYODAK	DJ		40,109	40,109	9
8	WYODAK	DRYFORK		81	81	10
8	WYODAK	RC		44,016	44,016	11
8	WYODAK	SGW		16,596	16,596	12
8	WYODAK	WYODAK		795	795	13
8	WYODAK	SHERIDAN		10,757	10,757	14
8	SHERIDAN	WYODAK		1,280	1,280	15
8	RC	WYODAK		3,888	3,888	16
8	DJ	RC		335	335	17
8	DJ	WYODAK		172	172	18
8	WYODAK	SGW		545	545	19
8	WYODAK	RC		240	240	20
8	WYODAK	DJ		3,084	3,084	21
8	SGW	WYODAK		283	283	22
8	DJ	RC		1,307	1,307	23
8	RC	DJ		3,911	3,911	24
8	RC	WYODAK		350	350	25
8	WSTAR	DJ		52	52	26
8	RC	SHERIDAN		725	725	27
8	RC	WSTAR		52	52	28
8	RC	DJ		1,116	1,116	29
8	RC	WYODAK		3,828	3,828	30
8	RC	DJ		1,758	1,758	31
8	RC	RC		827	827	32
8	RC	DJ				33
8	WYODAK	SGW		1	1	34
			252	**6,011,541**	**6,011,541**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
8	RC	DJ		305	305	1
8	WYODAK	ANTELOPE		424	424	2
8	RC	WYODAK		645	645	3
8	RC	DJ		395	395	4
8	DJ	RC		250	250	5
8	DJ	RC				6
	SGW	RC		4	4	7
	DJ	RC		849	849	8
8	WYODAK	DJ		283	283	9
8	RC	SGW		109	109	10
8	RC	DJ		5,035	5,035	11
8	RC	DJ		160	160	12
8	WYODAK	SGW		49	49	13
8	RC	SGW		935	935	14
8	DJ	RC		1,074	1,074	15
8	RC	DJ		1,956	1,956	16
8	SGW	RC		356	356	17
8	DJ	RC		100	100	18
8	RC	DJ		80	80	19
8	RC	RC		250	250	20
8	RC	DJ		240	240	21
8	DJ	SGW		40	40	22
8	WYODAK	SGW		150	150	23
8	RC	DJ		1,927	1,927	24
8	DJ	SGW		60	60	25
8	RC	SGW		127	127	26
8	RC	DJ		176	176	27
8	RC	DJ		425	425	28
8	DJ	RC		140	140	29
8	SGW	RC		54	54	30
8	RC	DJ		1	1	31
						32
						33
						34
			252	**6,011,541**	**6,011,541**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	272,373		272,373	1
				2
	24,911		24,911	3
3,292,800	8,005,408	1,644,322	12,942,530	4
	7,495,769	212,867	7,708,636	5
	2,593,597	151,747	2,745,344	6
	1,472,688	97,749	1,570,437	7
	60,114	2,706	62,820	8
1,679,620		291,636	1,971,256	9
937,205		135,231	1,072,436	10
839,810		128,169	967,979	11
3,639,178		608,887	4,248,065	12
	2,834	353	3,187	13
	1,818	226	2,044	14
	18,910	2,355	21,265	15
	3,352	418	3,770	16
	76	9	85	17
	1,026	128	1,154	18
	82	13	95	19
	285	34	319	20
	171	20	191	21
	1,324	155	1,479	22
	989	117	1,106	23
	23	3	26	24
	4,404	558	4,962	25
	25,522	3,482	29,004	26
	4,290	585	4,875	27
	68,663	9,369	78,032	28
	315	39	354	29
	283	35	318	30
	1,065	130	1,195	31
	1,804	213	2,017	32
	1,932	1,996	3,928	33
	1,745	1,804	3,549	34
10,388,613	**20,275,875**	**3,505,647**	**34,170,135**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	3,556	3,675	7,231	1
	48,959	50,595	99,554	2
	134	139	273	3
	19,824	20,487	40,311	4
	1,248	1,289	2,537	5
	469	484	953	6
	45	46	91	7
	169	175	344	8
	2,719	2,810	5,529	9
	2,542	2,627	5,169	10
	89	92	181	11
	1,610	1,663	3,273	12
	50	52	102	13
	627	648	1,275	14
	474	534	1,008	15
	119	134	253	16
	9	10	19	17
	4	4	8	18
	12	13	25	19
	55	62	117	20
	1	1	2	21
	89	70	159	22
	327	255	582	23
	1,325	1,036	2,361	24
	24	19	43	25
	59	46	105	26
	5	4	9	27
	18,202	14,231	32,433	28
	3	2	5	29
	7,559	8,018	15,577	30
	165	175	340	31
	3,055	3,241	6,296	32
	56	60	116	33
	1,491	1,582	3,073	34
10,388,613	**20,275,875**	**3,505,647**	**34,170,135**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	74	79	153	1
	316	335	651	2
	294	312	606	3
	720	764	1,484	4
	174	185	359	5
	43	46	89	6
	469	498	967	7
	10	11	21	8
	23,827	25,274	49,101	9
	48	51	99	10
	26,148	27,735	53,883	11
	9,859	10,458	20,317	12
	472	501	973	13
	6,390	6,778	13,168	14
	760	807	1,567	15
	2,310	2,450	4,760	16
	200	198	398	17
	102	101	203	18
	325	321	646	19
	143	142	285	20
	1,837	1,819	3,656	21
	169	167	336	22
	766	509	1,275	23
	2,293	1,523	3,816	24
	205	136	341	25
	30	20	50	26
	425	282	707	27
	30	20	50	28
	665	671	1,336	29
	2,279	2,180	4,459	30
	1,047	1,001	2,048	31
	492	471	963	32
		-7	-7	33
	1	1	2	34
10,388,613	**20,275,875**	**3,505,647**	**34,170,135**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	182	17	199	1
	253	-583	-330	2
	381	-240	141	3
	233	-147	86	4
	148	-93	55	5
		-89	-89	6
	2	4	6	7
	504	826	1,330	8
	168	275	443	9
	65	106	171	10
	2,988	4,898	7,886	11
	95	105	200	12
	29	32	61	13
	550	931	1,481	14
	632	1,069	1,701	15
	1,151	1,947	3,098	16
	200	-36	164	17
	56	-10	46	18
	45	-8	37	19
	147	-16	131	20
	141	-16	125	21
	176	22	198	22
	660	81	741	23
	2,275	624	2,899	24
	71	19	90	25
	150	41	191	26
	285	56	341	27
	355	141	496	28
	116	156	272	29
	45	60	105	30
	1	1	2	31
				32
				33
				34
10,388,613	**20,275,875**	**3,505,647**	**34,170,135**	

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FOOTNOTE DATA

Schedule Page: 328 Line No.: 1 Column: c

South Dakota State School of Mines and Technology

Schedule Page: 328 Line No.: 2 Column: a

Losses Received on RC DC Tie

Schedule Page: 328 Line No.: 4 Column: i

The volumes reported includes only Black Hills Power Native Load.

Schedule Page: 328 Line No.: 4 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 4 Column: n

Rapid City DC Tie. Black Hills Power is joint owner of the DC transmission tie that interconnects the Western and Eastern transmission grids. Dollar amounts shown are BHP's share of RC DC Tie revenues.

Schedule Page: 328 Line No.: 5 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 6 Column: a

Affiliate of Black Hills Power

Schedule Page: 328 Line No.: 6 Column: b

Affiliate of Black Hills Power

Schedule Page: 328 Line No.: 6 Column: c

Affiliate of Black Hills Power

Schedule Page: 328 Line No.: 6 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 7 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 8 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 9 Column: a

Affiliate of Black Hills Power

Schedule Page: 328 Line No.: 9 Column: b

Affiliate of Black Hills Power

Schedule Page: 328 Line No.: 9 Column: c

Basin Electric Power

Schedule Page: 328 Line No.: 9 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 10 Column: c

Municipal Energy Agency of Nebraska, Western Area Power Administration

Schedule Page: 328 Line No.: 10 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 11 Column: c

Tri-State Generation and Transmission

Schedule Page: 328 Line No.: 11 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 12 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 13 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC

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assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 14 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 15 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 16 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 17 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 18 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 19 Column: a

Affiliate of Black Hills Power

Schedule Page: 328 Line No.: 19 Column: b

Affiliate of Black Hills Power

Schedule Page: 328 Line No.: 19 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 20 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 21 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 22 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 23 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 24 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 25 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 26 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 27 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 28 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 29 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 30 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC

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assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 31 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 32 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 33 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328 Line No.: 34 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 1 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 2 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 3 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 4 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 5 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 6 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 7 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 8 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 9 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 10 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 11 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 12 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 13 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 14 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 15 Column: a

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Affiliate of Black Hills Power

Schedule Page: 328.1 Line No.: 15 Column: b

Affiliate of Black Hills Power

Schedule Page: 328.1 Line No.: 15 Column: c

Affiliate of Black Hills Power

Schedule Page: 328.1 Line No.: 15 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 16 Column: a

Affiliate of Black Hills Power

Schedule Page: 328.1 Line No.: 16 Column: b

Affiliate of Black Hills Power

Schedule Page: 328.1 Line No.: 16 Column: c

Affiliate of Black Hills Power

Schedule Page: 328.1 Line No.: 16 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 17 Column: a

Affiliate of Black Hills Power

Schedule Page: 328.1 Line No.: 17 Column: b

Affiliate of Black Hills Power

Schedule Page: 328.1 Line No.: 17 Column: c

Affiliate of Black Hills Power

Schedule Page: 328.1 Line No.: 17 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 18 Column: a

Affiliate of Black Hills Power

Schedule Page: 328.1 Line No.: 18 Column: b

Affiliate of Black Hills Power

Schedule Page: 328.1 Line No.: 18 Column: c

Affiliate of Black Hills Power

Schedule Page: 328.1 Line No.: 18 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 19 Column: a

Affiliate of Black Hills Power

Schedule Page: 328.1 Line No.: 19 Column: b

Affiliate of Black Hills Power

Schedule Page: 328.1 Line No.: 19 Column: c

Affiliate of Black Hills Power

Schedule Page: 328.1 Line No.: 19 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 20 Column: a

Affiliate of Black Hills Power

Schedule Page: 328.1 Line No.: 20 Column: b

Affiliate of Black Hills Power

Schedule Page: 328.1 Line No.: 20 Column: c

Affiliate of Black Hills Power

Schedule Page: 328.1 Line No.: 20 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 21 Column: a

Affiliate of Black Hills Power

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Schedule Page: 328.1 Line No.: 21 Column: b
Affiliate of Black Hills Power
Schedule Page: 328.1 Line No.: 21 Column: c
Affiliate of Black Hills Power
Schedule Page: 328.1 Line No.: 21 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.
Schedule Page: 328.1 Line No.: 22 Column: a
Affiliate of Black Hills Power
Schedule Page: 328.1 Line No.: 22 Column: b
Affiliate of Black Hills Power
Schedule Page: 328.1 Line No.: 22 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.
Schedule Page: 328.1 Line No.: 23 Column: a
Affiliate of Black Hills Power
Schedule Page: 328.1 Line No.: 23 Column: b
Affiliate of Black Hills Power
Schedule Page: 328.1 Line No.: 23 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.
Schedule Page: 328.1 Line No.: 24 Column: a
Affiliate of Black Hills Power
Schedule Page: 328.1 Line No.: 24 Column: b
Affiliate of Black Hills Power
Schedule Page: 328.1 Line No.: 24 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.
Schedule Page: 328.1 Line No.: 25 Column: a
Affiliate of Black Hills Power
Schedule Page: 328.1 Line No.: 25 Column: b
Affiliate of Black Hills Power
Schedule Page: 328.1 Line No.: 25 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.
Schedule Page: 328.1 Line No.: 26 Column: a
Affiliate of Black Hills Power
Schedule Page: 328.1 Line No.: 26 Column: b
Affiliate of Black Hills Power
Schedule Page: 328.1 Line No.: 26 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.
Schedule Page: 328.1 Line No.: 27 Column: a
Affiliate of Black Hills Power
Schedule Page: 328.1 Line No.: 27 Column: b
Affiliate of Black Hills Power
Schedule Page: 328.1 Line No.: 27 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.
Schedule Page: 328.1 Line No.: 28 Column: a
Affiliate of Black Hills Power
Schedule Page: 328.1 Line No.: 28 Column: b
Affiliate of Black Hills Power
Schedule Page: 328.1 Line No.: 28 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC

assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 29 Column: a

Affiliate of Black Hills Power

Schedule Page: 328.1 Line No.: 29 Column: b

Affiliate of Black Hills Power

Schedule Page: 328.1 Line No.: 29 Column: c

Affiliate of Black Hills Power

Schedule Page: 328.1 Line No.: 29 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 30 Column: b

Public Service Company of New Mexico, Public Service Company of Colorado, Black Hills Power

Schedule Page: 328.1 Line No.: 30 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 31 Column: c

Affiliate of Black Hills Power

Schedule Page: 328.1 Line No.: 31 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 32 Column: b

Public Service Company of New Mexico, Public Service Company of Colorado, Black Hills Power

Schedule Page: 328.1 Line No.: 32 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 33 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.1 Line No.: 34 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 1 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 2 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 3 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 4 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 5 Column: c

Western Area Power Administration

Schedule Page: 328.2 Line No.: 5 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 6 Column: c

Western Area Power Administration

Schedule Page: 328.2 Line No.: 6 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 7 Column: c

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Tristate

Schedule Page: 328.2 Line No.: 7 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 8 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 9 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 10 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 11 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 12 Column: c

Holy Cross

Schedule Page: 328.2 Line No.: 12 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 13 Column: c

Holy Cross

Schedule Page: 328.2 Line No.: 13 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 14 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 15 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

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Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 17 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 18 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 19 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 20 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 21 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 22 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 23 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) 04/16/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 328.2 Line No.: 24 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 25 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 26 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

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Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

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Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

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Schedule Page: 328.2 Line No.: 32 Column: m
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Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.2 Line No.: 34 Column: c
Municipal Energy Agency of Nebraska

Schedule Page: 328.2 Line No.: 34 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

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Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.3 Line No.: 2 Column: c
Pacificorp

Schedule Page: 328.3 Line No.: 2 Column: m
Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

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Name of Respondent Black Hills Power, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report 2020/Q4

FOOTNOTE DATA

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.3 Line No.: 8 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

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Schedule Page: 328.3 Line No.: 13 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

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Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

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Schedule Page: 328.3 Line No.: 25 Column: m

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) __ A Resubmission	04/16/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 328.3 Line No.: 26 Column: m

Other charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.

Schedule Page: 328.3 Line No.: 27 Column: m

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Schedule Page: 328.3 Line No.: 31 Column: m

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
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25					
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28					
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31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Powder River Energy	NF	1,966	1,966				
2	Pacificorp	FNS	298,519	298,518		1,478,135		1,478,135
3	Pacificorp	LFP	439,445	439,445	1,776,314			1,776,314
4	Pacificorp	NF	3,395,147	3,395,147				
5	Idaho Power	NF	1,790	1,790		9,299		9,299
6	Basin Electric	NF	39,399	39,399		58,993		58,993
7	Northwestern Energy	SFP	2,735	2,735		15,452		15,452
8	Western Area Power	NF	5,888	5,888		297,942		297,942
9	Tri-State Generation	NF	1,161	1,161		7,191		7,191
10	Southwest Power Pool	NF	27,798	27,798		126,469		126,469
11	Public Service Co	NF	3,616	3,616		11,299		11,299
12	Public Service Co	NF	840	840		5,533		5,533
13	TransAlta	NF				1,813		1,813
14	CLFP	NF				255,579		255,579
15	Black Hills Wyoming	NF				-83		-83
16	Western Area Power	OS				161,958		161,958
	TOTAL		6,299,556	6,299,555	5,019,951	15,840,023	2,059,443	22,919,417

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	TRANSFER OF ENERGY Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	BHBE - CUS	LFP	12,974	12,974	3,241,428			3,241,428
2	BHBE - CUS	NF	470	470	2,209			2,209
3	Transmission Accruals	OS				-234,233		-234,233
4	Western Area Power	OS					597,004	597,004
5	BHBE - CUS	FNS	1,926,000	1,926,000		13,502,868	1,315,496	14,818,364
6	BHBE - CUS	NF	141,808	141,808		141,808	146,943	288,751
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		6,299,556	6,299,555	5,019,951	15,840,023	2,059,443	22,919,417

Name of Respondent Black Hills Power, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report 2020/Q4

FOOTNOTE DATA

Schedule Page: 332 Line No.: 8 Column: a

Western Area Power Administration Loveland

Schedule Page: 332 Line No.: 11 Column: a

Public Service Company of Colorado

Schedule Page: 332 Line No.: 12 Column: a

Public Service Company of New Mexico

Schedule Page: 332 Line No.: 14 Column: a

Cheyenne Light, Fuel & Power

Affiliate of Black Hills Power

Schedule Page: 332 Line No.: 15 Column: a

Affiliate of Black Hills Power

Schedule Page: 332 Line No.: 16 Column: a

Western Area Power Administration

Schedule Page: 332.1 Line No.: 1 Column: a

Affiliate transactions - BHP is a joint owner of the BHBE Transmission System; Amounts shown are charges from BHBE. Amounts included in Other Charges represent ancillary charges for Reactive Voltage Support, Scheduling, and FERC Assesments.

Rapid City DC Tie Transactions

Schedule Page: 332.1 Line No.: 2 Column: a

Affiliate transactions - BHP is a joint owner of the BHBE Transmission System; Amounts shown are charges from BHBE. Amounts included in Other Charges represent ancillary charges for Reactive Voltage Support, Scheduling, and FERC Assesments.

Rapid City DC Tie Transactions

Schedule Page: 332.1 Line No.: 4 Column: a

Western Area Power Administration

Schedule Page: 332.1 Line No.: 4 Column: g

Regulation costs paid to WAPA

Schedule Page: 332.1 Line No.: 5 Column: g

Affiliate transactions - BHP is a joint owner of the BHBE Transmission System; Amounts shown are charges from BHBE. Amounts included in Other Charges represent ancillary charges for Reactive Voltage Support, Scheduling, and FERC Assesments.

Schedule Page: 332.1 Line No.: 6 Column: g

Affiliate transactions - BHP is a joint owner of the BHBE Transmission System; Amounts shown are charges from BHBE. Amounts included in Other Charges represent ancillary charges for Reactive Voltage Support, Scheduling, and FERC Assesments.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	83,453
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	2,214
6	Director's Fees and Expenses	7,806
7	Bank Fees	300,053
8	Travel	9,570
9	Materials & Supplies	34,457
10	Economic Development	531,424
11	Labor & Loadings	61,655
12	Handouts & Brochures	25,231
13	Contractor/Consultants	8,109
14		
15		
16		
17		
18		
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43		
44		
45		
46	TOTAL	1,063,972

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant					
2	Steam Production Plant	10,111,579			1,774,436	11,886,015
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	5,384,819	2,167			5,386,986
7	Transmission Plant	5,317,320				5,317,320
8	Distribution Plant	12,158,037				12,158,037
9	Regional Transmission and Market Operation					
10	General Plant	9,601,773				9,601,773
11	Common Plant-Electric					
12	TOTAL	42,573,528	2,167		1,774,436	44,350,131

B. Basis for Amortization Charges

Amortization of other electric plant will occur over 10 years

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Steam Production Plant						
13	Osage	817	60.00	-22.00	12.07		
14	Wyodak	115,532	58.00	-13.00	2.86		24.20
15	Neil Simpson II	168,767	60.00	-14.00	2.90		28.40
16	Wygen III	141,559	60.00	-13.00	2.64		40.40
17	Subtotal	426,675					
18	Other Production Plant						
19	Lange CT	33,290	44.00	-5.00	2.29		29.60
20	Neil Simpson I CT	35,264	44.00	-5.00	2.56		28.30
21	Ben French CT	22,397	44.00	-13.00	2.61		14.20
22	Ben French Diesel CT	2,182	45.00	-22.00	5.06		6.50
23	CPGS	90,044	40.00	-4.00	2.98		42.00
24	Corriedale	50,797	25.00		4.28		25.00
25	Subtotal	233,974					
26	Transmission Plant						
27	(352)Structures and Im	1,916	50.00	-10.00	1.83		39.80
28	(353)Station Equipment	68,376	42.00	-5.00	2.13		35.80
29	(354)Towers and Fistur	956	60.00	-20.00	1.74		55.60
30	(355)Poles and Fixture	86,115	55.00	-30.00	2.74		37.50
31	(356)Overhead Conducto	70,975	60.00	-20.00	2.05		44.70
32	(359)Roads & Trails	7	60.00		1.72		31.50
33	Subtotal	228,345					
34	Distribution Plant						
35	(361)Structures and Im	1,989	40.00	-5.00	2.45		33.30
36	(362)Station Equipment	110,146	45.00	-10.00	2.27		34.10
37	(364)Poles, Towers &	113,836	50.00	-70.00	3.64		37.00
38	(365)Overhead Conducto	68,195	50.00	-20.00	2.23		38.50
39	(366)Underground Cond	13,081	37.00	-5.00	2.81		33.10
40	(367)Underground Cond	59,712	40.00	-5.00	2.32		30.10
41	(368)Line Transformers	52,260	36.00		2.41		27.10
42	(369)Services	39,512	62.00	-50.00	2.29		51.30
43	(370)Meters	10,133	21.00		5.23		18.30
44	(371)Installation on C	2,749	30.00	-10.00	3.22		22.20
45	(373)Street Lighting	2,219	25.00	-15.00	3.69		17.10
46	Subtotal	473,832					
47	General Plant						
48	(390)Structures and Im	81,573	40.00	-10.00	1.67		32.40
49	(391)Office Furniture	16,745	9.80		13.82		5.90
50	(392)Transportation Eq	19,511	13.00	-10.00	3.45		10.50

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	(393)Stores Equipment	437	20.00		9.32		4.50
13	(394)Tools, Shop, & Ga	3,449	25.00		3.33		17.00
14	(395)Laboratory Equip	770	25.00		7.46		13.20
15	(396)Power Operated Eq	4,169	30.00	-20.00	1.28		26.70
16	(397)Communication Equ	7,278	20.00		5.63		13.70
17	(398)Miscellaneous Equ	1,231	20.00		5.80		13.20
18	Subtotal	135,163					
19							
20	Total	1,497,989					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	FERC Assessment	418,548		418,548	
2	Rate Case Expenses/Other				1,472,327
3	PUC Assesments	433,204	110,486	543,690	
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46	TOTAL	851,752	110,486	962,238	1,472,327

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Reg Serv.	928						1
				588-928	420,665	1,051,661	2
Reg Serv.	588						3
							4
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					420,665	1,051,661	46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
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DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	4,098,350		
4	Transmission	1,822,606		
5	Regional Market			
6	Distribution	2,816,272		
7	Customer Accounts	868,652		
8	Customer Service and Informational	303,152		
9	Sales	26,010		
10	Administrative and General	14,267,948		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	24,202,990		
12	Maintenance			
13	Production	2,523,715		
14	Transmission	75,282		
15	Regional Market			
16	Distribution	1,428,687		
17	Administrative and General	11,261		
18	TOTAL Maintenance (Total of lines 13 thru 17)	4,038,945		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	6,622,065		
21	Transmission (Enter Total of lines 4 and 14)	1,897,888		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	4,244,959		
24	Customer Accounts (Transcribe from line 7)	868,652		
25	Customer Service and Informational (Transcribe from line 8)	303,152		
26	Sales (Transcribe from line 9)	26,010		
27	Administrative and General (Enter Total of lines 10 and 17)	14,279,209		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	28,241,935		28,241,935
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance	335,280		335,280
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	28,577,215		28,577,215
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	3,992,923		3,992,923
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	3,992,923		3,992,923
72	Plant Removal (By Utility Departments)			
73	Electric Plant	245,060		245,060
74	Gas Plant			
75	Other (provide details in footnote):		3,104,796	3,104,796
76	TOTAL Plant Removal (Total of lines 73 thru 75)	245,060	3,104,796	3,349,856
77	Other Accounts (Specify, provide details in footnote):			
78	Other Reg Assets	46,295		46,295
79	Other A/R	305		305
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81				
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87				
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89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	46,600		46,600
96	TOTAL SALARIES AND WAGES	32,861,798	3,104,796	35,966,594

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) __ A Resubmission	04/16/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 354 Line No.: 75 Column: c

Cleared through 163	757,044
Cleared through 184	2,347,752
Total	3,104,796

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
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45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	3,456,889	KW/M	859,376	11,540,275	KW/M	2,802,844
2	Reactive Supply and Voltage	3,456,889	KW/M	1,230,745	11,540,275	KW/M	1,723,265
3	Regulation and Frequency Response	4,795	MW	597,004			
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other	1,922,111	MHW	145,038	5,790,398	MWH	436,910
8	Total (Lines 1 thru 7)	8,840,684		2,832,163	28,870,948		4,963,019

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) __ A Resubmission	04/16/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 398   Line No.: 7   Column: d

Other is FERC Annual Charge Assesment

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM: BHBE System

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	894	16	700	278	444	255			15
2	February	900	20	800	272	441	255			5
3	March	927	16	1200	276	432	255			55
4	Total for Quarter 1				826	1,317	765			75
5	April	747	13	1700	234	420	255			10
6	May	769	11	1100	224	355	255			70
7	June	777	24	1500	299	366	252			24
8	Total for Quarter 2				757	1,141	762			104
9	July	835	3	1700	325	375	252			33
10	August	859	25	1500	357	394	252			474
11	September	754	5	1700	305	366	252		188	160
12	Total for Quarter 3				987	1,135	756		188	667
13	October	741	23	1000	259	398	252			18
14	November	727	21	1800	234	383	252			78
15	December	773	17	1800	257	400	252			13
16	Total for Quarter 4				750	1,181	756			109
17	Total Year to Date/Year				3,320	4,774	3,039		188	955

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) __ A Resubmission	04/16/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 400   Line No.: 17   Column: g

Contract MW amount

Schedule Page: 400   Line No.: 17   Column: j

Non Firm MW total for the peak hour

Name of Respondent Black Hills Power, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report End of 2020/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	1,765,257
3	Steam	1,556,845			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	104,505
5	Hydro-Conventional				
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	1,207,480
7	Other	344,164			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	1,901,009	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
10	Purchases	1,337,125	27	Total Energy Losses	92,429
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	3,169,671
12	Received	3,759			
13	Delivered	72,222			
14	Net Exchanges (Line 12 minus line 13)	-68,463			
15	Transmission For Other (Wheeling)				
16	Received	6,011,541			
17	Delivered	6,011,541			
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	3,169,671			

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM: Black Hills Power

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	288,112	52,041	293	15	1800
30	February	271,799	31,667	304	19	0900
31	March	260,922	22,036	286	30	1100
32	April	246,416	46,985	252	2	0900
33	May	225,029	20,396	245	20	1700
34	June	255,366	38,624	334	29	1600
35	July	294,136	46,366	354	23	1600
36	August	297,286	38,791	378	12	1900
37	September	256,754	46,405	305	5	1700
38	October	247,643	33,412	315	3	1900
39	November	249,902	34,734	254	12	1800
40	December	276,306	42,948	287	23	1700
41	TOTAL	3,169,671	454,405			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Ben French Station* (b)	Plant Name: *Ben French Station* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine	Internal Combustion
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional
3	Year Originally Constructed	1977	1965
4	Year Last Unit was Installed	1979	1965
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	100.80	10.00
6	Net Peak Demand on Plant - MW (60 minutes)	98	10
7	Plant Hours Connected to Load	477	13
8	Net Continuous Plant Capability (Megawatts)	80	10
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	12875175	-410341
13	Cost of Plant: Land and Land Rights	7554	0
14	Structures and Improvements	1349159	0
15	Equipment Costs	21471107	2182272
16	Asset Retirement Costs	-419523	0
17	Total Cost	22408297	2182272
18	Cost per KW of Installed Capacity (line 17/5) Including	222.3045	218.2272
19	Production Expenses: Oper, Supv, & Engr	217005	18183
20	Fuel	452203	11955
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	3477	58096
26	Misc Steam (or Nuclear) Power Expenses	0	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	962	900
30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	342244	14904
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	1015891	104038
35	Expenses per Net KWh	0.0789	-0.2535

Line No.	Item (a)	(b)			(c)		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Oil	Gas			Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Bbl	Mcf			Bbl	
38	Quantity (Units) of Fuel Burned	2	200723	0	0	49	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	135285	1072	0	0	135981	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	6495.470	2.190	0.000	0.000	243.480	0.000
41	Average Cost of Fuel per Unit Burned	6495.470	2.190	0.000	0.000	243.480	0.000
42	Average Cost of Fuel Burned per Million BTU	1143.170	4.090	0.000	0.000	85.260	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	-0.010	0.031	0.000	0.000	-0.029	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	-683.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Lange CT Facility* (b)			Plant Name: *WYGEN 3* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine #1			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	2000			2010		
4	Year Last Unit was Installed	2000			2010		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	40.00			110.00		
6	Net Peak Demand on Plant - MW (60 minutes)	39			57		
7	Plant Hours Connected to Load	1135			8377		
8	Net Continuous Plant Capability (Megawatts)	38			57		
9	When Not Limited by Condenser Water	0			57		
10	When Limited by Condenser Water	0			57		
11	Average Number of Employees	0			36		
12	Net Generation, Exclusive of Plant Use - KWh	35181760			434493000		
13	Cost of Plant: Land and Land Rights	2705			9529565		
14	Structures and Improvements	503390			135980056		
15	Equipment Costs	35278560			0		
16	Asset Retirement Costs	-2471077			-3802853		
17	Total Cost	33313578			141706768		
18	Cost per KW of Installed Capacity (line 17/5) Including	832.8395			1288.2433		
19	Production Expenses: Oper, Supv, & Engr	104041			190250		
20	Fuel	840564			5561594		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			398879		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	14426			229191		
26	Misc Steam (or Nuclear) Power Expenses	0			309167		
27	Rents	1305			1743719		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	900			258829		
30	Maintenance of Structures	0			184203		
31	Maintenance of Boiler (or reactor) Plant	0			854978		
32	Maintenance of Electric Plant	581426			149779		
33	Maintenance of Misc Steam (or Nuclear) Plant	4517			5395		
34	Total Production Expenses	1547179			9885984		
35	Expenses per Net KWh	0.0440			0.0228		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		Gas		Coal	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		Mcf		Tons	Mcf	
38	Quantity (Units) of Fuel Burned	0	370896	0	309778	6332	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	1075	0	8099	1067	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	2.270	0.000	14.760	5.100	0.000
41	Average Cost of Fuel per Unit Burned	0.000	2.270	0.000	17.850	5.100	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	2.110	0.000	1.100	4.780	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.024	0.000	0.002	0.063	0.000
44	Average BTU per KWh Net Generation	0.000	11333.000	0.000	11549.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Neil SImpson Unit 2* (d)	Plant Name: *WYODAK* (e)	Plant Name: *Neil Simpson CT #1* (f)	Line No.
Steam	Steam	Gas Turbine #1	1
Conventional	Conventional	Conventional	2
1995	1978	2000	3
1999	1978	2000	4
90.00	72.41	40.00	5
84	69	39	6
8191	8264	2191	7
80	67	38	8
80	67	0	9
80	67	0	10
40	110	0	11
651324000	467710000	73862000	12
117401	109191	0	13
29009875	9215536	355321	14
144957668	106316771	35375345	15
-1308190	0	-768986	16
172776754	115641498	34961680	17
1919.7417	1597.0377	874.0420	18
324245	589746	77687	19
8858682	5291109	1572662	20
0	0	0	21
671806	518802	0	22
0	0	0	23
0	0	0	24
360007	0	110214	25
534796	554544	0	26
916687	0	159586	27
0	0	0	28
539781	12760	0	29
373923	0	6941	30
2512475	1565847	0	31
648187	173899	503573	32
7234	42300	0	33
15747823	8749007	2430663	34
0.0242	0.0187	0.0329	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Gas	Coal			Coal			Gas		36
Mcf	Tons			Tons			Mcf		37
12201	508848	0	0	301944	0	0	689094	0	38
8094	1067	0	0	81	0	0	1067	0	39
2.680	14.790	0.000	0.000	16.530	0.000	0.000	2.280	0.000	40
2.680	17.350	0.000	0.000	17.520	0.000	0.000	2.280	0.000	41
0.330	8.130	0.000	0.000	1.080	0.000	0.000	2.140	0.000	42
0.000	0.002	0.000	0.000	0.011	0.000	0.000	0.021	0.000	43
0.000	1667.000	0.000	0.000	10471.000	0.000	0.000	9955.000	0.000	44

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: CPGS (d)	Plant Name: (e)	Plant Name: (f)	Line No.
Combined Cycle			1
Conventional			2
2014			3
2014			4
100.00	0.00	0.00	5
60	0	0	6
5283	0	0	7
60	0	0	8
0	0	0	9
0	0	0	10
18	0	0	11
222638900	0	0	12
149038	0	0	13
604102	0	0	14
212931	0	0	15
0	0	0	16
966071	0	0	17
9.6607	0	0	18
466551	0	0	19
3712128	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
402791	0	0	25
0	0	0	26
121314	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
713047	0	0	32
0	0	0	33
5415831	0	0	34
0.0243	0.0000	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
	Gas								36
	Mcf								37
0	1732257	0	0	0	0	0	0	0	38
0	1050	0	0	0	0	0	0	0	39
0.000	2.140	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	2.140	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	2.040	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	8170.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent Black Hills Power, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report 2020/Q4

FOOTNOTE DATA

Schedule Page: 403 Line No.: -1 Column: e

WYODAK is 20% owned by Black Hills Power.

Schedule Page: 402.1 Line No.: -1 Column: c

WYGEN 3 is 52% owned by Black Hills Power.

Schedule Page: 403.1 Line No.: -1 Column: d

Cheyenne Prairie Generating Station is 58% owned by Black Hills Power.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
			7
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			10
			11
			12
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			36
			37
			38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Corriedale Wind Farm	2020	52.50	32.0	17,967,824	50,917,981
2						
3						
4						
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6						
7						
8						
9						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
	66,670		137	Wind		1
						2
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) __ A Resubmission	04/16/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 410 Line No.: 1 Column: a

The Corriedale Wind Farm is 62% owned by Black Hills Power.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	SOUTH DAKOTA							
2	Wyodak	Lookout	230.00	230.00	H-Wood	11.03		1
3	Lookout	Lange	230.00	230.00	H-Wood	54.53		1
4	Lange	West Hill	230.00	230.00	H-Wood	55.17		1
5	West Hill	Stegall	230.00	230.00	H-Wood	33.96		1
6	West Hill	Minnekahta	230.00	230.00	H-Wood	9.48		1
7	Minnekahta	Osage	230.00	230.00	H-Wood	23.32		1
8	Lange	Ben French	69.00	69.00	H-Wood	2.64	5.30	3
9	DC Tie West	South Rapid City	230.00	230.00	SP-Steel	4.00		1
10	Osage	Yellowcreek	230.00	230.00	H-Wood	21.12		1
11	Osage	Lange	230.00	230.00	H-Wood	46.02		1
12	WYOMING							
13	Wyodak	Lookout	230.00	230.00	H-Wood	73.26		1
14	Osage	Minnekahta	230.00	230.00	H-Wood	33.94		1
15	Osage	Wyodak	230.00	230.00	H-Wood	57.46		1
16	NS I	NS II	69.00	69.00	SP-Steel	0.80		1
17	Osage	Yellowcreek	230.00	230.00	H-Wood	22.02		1
18	NS I	Wyodak	69.00	69.00	H-Wood	0.29		1
19	Donkey Creek	Pumpkin Buttes	230.00	230.00	H-Wood	49.75		1
20	Wygen 3	Donkey Creek	230.00	230.00	SP-Steel	0.76		1
21	Pumpkin Buttes	Windstar	230.00	230.00	H-Wood	68.20		1
22	Windstar	Dave Johnson	230.00	230.00	H-Wood	2.56		1
23	Donkey Creek	Wyodak Tie Line #2	230.00	230.00	Steel	1.06		2
24	WY 1.14 Tap	Wyodak Baghouse	230.00	230.00	H-Wood	0.10		1
25	Teckla	Osage	230.00	230.00	H-Wood	81.55		1
26	Osage	Lange	230.00	230.00	H-Wood	19.27		1
27	NEBRASKA							
28	West Hill	Stegall	230.00	230.00	H-Wood	94.47		1
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	766.76	5.30	28

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1272 KCM ACSR								1
1272 KCM ACSR	9,800	753,872	763,672					2
1272 KCM ACSR	105,653	3,567,602	3,673,255					3
1272 KCM ACSR	465,310	18,735,200	19,200,510					4
1272 KCM ACSR	17,701	8,942,404	8,960,105					5
1272 KCM ACSR	11	854,903	854,914					6
1272 KCM ACSR	151,235	2,236,492	2,387,727					7
795 KCM ACSR		446,580	446,580					8
1272 KCM ACSR	127,145	630,238	757,383					9
1272 KCM ACSR	1,533	273,459	274,992					10
1272 KCM ACSR	1,512,278	24,375,828	25,888,106					11
								12
1272 KCM ACSR	49,542	4,989,094	5,038,636					13
1272 KCM ACSR	96,159	2,849,287	2,945,446					14
1272 KCM ACSR	162,516	4,736,703	4,899,219					15
795 KCM ACSR		304,794	304,794					16
1272 KCM ACSR	13,308	292,380	305,688					17
795 KCM ACSR		177,860	177,860					18
1272 KCM ACSR	1,280,649	9,994,030	11,274,679					19
1272 KCM ACSR	3,488	295,400	298,888					20
1272 KCM ACSR	2,204,210	13,502,595	15,706,805					21
1272 KCM ACSR		686,732	686,732					22
1272 KCM ACSR		988,382	988,382					23
336.4 ACSR		3,989	3,989					24
1272 KCM ACSR	2,439,362	24,610,209	27,049,571					25
1272 KCM ACSR	589,324	10,363,181	10,952,505					26
								27
1272 KCM ACSR	329,367	23,194,410	23,523,777					28
								29
								30
								31
								32
								33
								34
								35
	9,558,591	157,805,624	167,364,215					36

Name of Respondent Black Hills Power, Inc.	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report 2020/Q4

FOOTNOTE DATA

Schedule Page: 422 Line No.: 9 Column: a

DC Tie West to South Rapid City is 35% owned by Black Hills Power and 65% owned by Basin Electric.

Schedule Page: 422 Line No.: 10 Column: a

Osage to Yellowcreek is 7.87% owned by Black Hills Power and 92.13% owned by Basin Electric.

Schedule Page: 422 Line No.: 17 Column: a

Osage to Yellowcreek is 7.87% owned by Black Hills Power and 92.13% owned by Basin Electric.

Schedule Page: 422 Line No.: 22 Column: a

Windstar to Dave Johnson is 56.25% owned by Black Hills Power and 43.75% owned by Pacificorp.

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
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43							
44	TOTAL						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
									2
									3
									4
									5
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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Anamosa, Rapid City, SD	Dist. Unattended	69.00	12.47	
2	Argyle, SD	Dist. Unattended	69.00	12.47	
3	Belle Creek, MT	Dist. Unattended	69.00	24.90	
4	Ben French 26 Rapid City, SD	Dist. Unattended	69.00	24.90	
5	Butte Pipeline, Alzada, MT	Dist. Unattended	69.00	2.40	
6	Cambell St, Rapid City, SD	Dist. Unattended	69.00	12.47	
7	Cemetery, Rapid City, SD	Dist. Unattended	69.00	12.47	
8	Century, Rapid City, SD	Dist. Unattended	69.00	12.47	
9	Cleveland St. Rapid City, SD	Dist. Unattended	69.00	12.47	
10	Cross Street, Rapid City, SD	Dist. Unattended	69.00	12.47	
11	Colony Substation, Colony, WY	Dist. Unattended	69.00	24.90	
12	Custer, SD	Dist. Unattended	69.00	12.47	
13	Custer, SD	Dist. Unattended	69.00	24.90	
14	East Meade, Rapid City, SD	Dist. Unattended	69.00	12.47	
15	East North, Rapid City, SD	Dist. Unattended	69.00	12.47	
16	Edgemont City, Edgemont, SD	Dist. Unattended	69.00	12.47	
17	Fifth Street, Rapid City, SD	Dist. Unattended	69.00	12.47	
18	Forty Fourth Street, Rapid City, SD	Dist. Unattended	69.00	12.47	
19	Fourth Street, Rapid City, SD	Dist. Unattended	69.00	4.16	
20	Hill City, SD	Dist. Unattended	69.00	24.90	
21	Hillsview, Spearfish, SD	Dist. Unattended	69.00	12.47	
22	Hot Springs, SD	Dist. Unattended	69.00	12.47	
23	Lange, Rapid City, SD	Dist. Unattended	69.00	24.90	
24	Mall, Rapid City, SD	Dist. Unattended	69.00	24.90	
25	Merillat, Rapid City, SD	Dist. Unattended	69.00	12.47	
26	Mountain View, Spearfish, SD	Dist. Unattended	69.00	24.90	
27	Newcastle, WY	Dist. Unattended	69.00	4.16	
28	Newell, SD	Dist. Unattended	24.00	4.16	
29	Newell, SD	Dist. Unattended	24.00	12.47	
30	Neil Simpson ST 4160 East, Gillette, WY	Dist. Unattended	69.00	4.16	
31	Neil Simpson 4160 West, Gillette, WY	Dist. Unattended	69.00	4.16	
32	Osage, WY Osage City Sub Osage, WY	Dist. Unattended	69.00	12.47	
33	Pleasant Valley, Rapid City, SD	Dist. Unattended	69.00	12.47	
34	Pluma, Deadwood, SD	Dist. Unattended	69.00	12.47	
35	Rapid City South, Rapid City, SD	Dist. Unattended	69.00	12.47	
36	Radio Drive Rapid City, SD	Dist. Unattended	69.00	12.47	
37	Richmond Hill, Lead, SD	Dist. Unattended	69.00	12.47	
38	Spearfish City, Spearfish, SD	Dist. Unattended	69.00	12.47	
39	Spearfish Park, Spearfish, SD	Dist. Unattended	69.00	12.47	
40	Spruce Gulch, Deadwood, SD	Dist. Unattended	69.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Sturgis, SD	Dist. Unattended	69.00	12.47	
2	Sundance Hill, Belle Fourche, SD	Dist. Unattended	69.00	24.90	
3	Sundance Hill, Belle Fourche, SD	Dist. Unattended	69.00	4.16	
4	Thirty Eight St., Rapid City, SD	Dist. Unattended	69.00	12.47	
5	Trojan, Lead, SD	Dist. Unattended	69.00	12.47	
6	Upton, WY Upton city Sub Upton, WY	Dist. Unattended	69.00	2.40	
7	West Boulevard, Rapid City, SD	Dist. Unattended	69.00	4.16	
8	West Hill, Hot Springs, SD	Dist. Unattended	69.00	12.47	
9	Whitewood, SD	Dist. Unattended	69.00	24.90	
10	Windy Flats, Nemo	Dist. Unattended	69.00	12.47	
11	Portable Sub, Rapid City, SD	Dist. Unattended	69.00	24.90	
12	Pactola, Rapid City, SD	Dist. Unattended	69.00	24.90	
13	Piedmont, Piedmont, SD	Dist. Unattended	69.00	24.90	
14	Ben French Diesels, Rapid City, SD	Trans. Unattended	4.16	69.00	
15	Ben French Combustion Trubines, Rapid City, SD	Trans. Unattended	13.80	69.00	
16	Cambell ST./East Tie, Rapid City, SD	Trans. Unattended	115.00	69.00	
17	Lange, Rapid City, SD	Trans. Unattended	230.00	69.00	13.20
18	Lange CT, Rapid City, SD	Trans. Unattended	13.80	69.00	
19	Lookout, Spearfish, SD	Trans. Unattended	230.00	69.00	13.20
20	Neil Simpson 2 Gillette, WY	Trans. Unattended	13.80	69.00	
21	Neil Simpson CT #1, Gillette, WY	Trans. Unattended	13.80	69.00	
22	Osage 230, Osage WY	Trans. Unattended	230.00	69.00	13.20
23	West Hill Hot Springs, SD	Trans. Unattended	230.00	69.00	13.20
24	Wyodak 69 Sub, Gillette, WY	Trans. Unattended	230.00	69.00	13.20
25	Yellow Creek, Lead, SD	Trans. Unattended	230.00	69.00	13.20
26	Rapid City South, Rapid City, SD	Trans. Unattended	230.00	69.00	
27	Rapid City AC_DC_AC Tie Rapid City SD	Trans. Unattended	230.00	230.00	
28	Minnekahta Substation, Hot Springs, SD	Trans. Unattended	230.00	69.00	13.20
29	Blucksberg, Sturgis, SD	Dist. Unattended	69.00	24.90	
30	Sagebrush, Newcastle, WY	Trans. Unattended	230.00	69.00	13.20
31	West Rapid City, Rapid City, SD	Trans. Unattended	230.00	69.00	13.20
32	Red Rock, Rapid City, SD	Dist. Unattended	69.00	12.47	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
20	1		Fans LTC		20	1
5	1		Fans		5	2
14	1		Fans		14	3
28	1		Fans. Regs		28	4
12	3				12	5
14	1		Fans LTC		14	6
28	2		Fans LTC		28	7
28	2		Fans LTC		28	8
25	1		Fans LTC		25	9
14	1		Fans LTC		14	10
14	1		Fans		14	11
10	1		Fans LTC		10	12
10	1		Fans. Regs		10	13
20	1		Fans LTC		20	14
34	2		Fans LTC		34	15
14	1		Fans LTC		14	16
25	1		Fans LTC		25	17
14	1		Fans LTC		14	18
21	2		Fans LTC		21	19
14	1		Fans		14	20
14	1		Fans LTC		14	21
14	1		Fans LTC		14	22
14	1		Fans		14	23
14	1		Fans Regs		14	24
28	2		Fans LTC		28	25
14	1		Fans Regs		14	26
10	1		Fans Regs		10	27
2	1		Fans Regs		2	28
1	3		Fans		1	29
14	1		Fans		14	30
10	1		Fans		10	31
10	1		Fans		10	32
20	1		Fans LTC		20	33
21	2		Fans LTC		21	34
34	2		Fans LTC		34	35
34	2		Fans LTC		34	36
5	1				5	37
14	1		Fans LTC		14	38
14	1		Fans LTC		14	39
14	1		Fans LTC		14	40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
28	2		Fans LTC		28	1
10	1		Fans Regs		10	2
7	1		Fans LTC		7	3
14	1		Fans LTC		14	4
10	1		Fans LTC		10	5
3	1		Fans Regs		3	6
10	1		Fans LTC		10	7
10	1		Fans Regs		10	8
14	1		Fans Regs		14	9
7	1		Fans		7	10
10	1		Fans		10	11
9	1		Fans		9	12
14	1		Fans Regs		14	13
14	1		Fans		14	14
120	4		Fans & Pumps		120	15
80	2		Fans & Pumps		80	16
250	2		Fans & Pumps		250	17
75	1		Fans		75	18
250	2		Fans Pumps LTC		250	19
150	1		Fans		150	20
84	1		Fans		84	21
70	1		Fans		70	22
50	1		Fans Pumps LTC		50	23
100	1		Fans Pumps LTC		100	24
100	1		Fans Pumps LTC		100	25
150	1	1	Fans LTC		150	26
218	4		Fans LTC		543	27
70	1		Fans LTC		70	28
20	1		Fans LTC		20	29
100	1		Fans LTC		100	30
150	1		Fans LTC		150	31
20	1		Fans LTC		20	32
						33
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Name of Respondent Black Hills Power, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report 2020/Q4

FOOTNOTE DATA

Schedule Page: 426.1 Line No.: 17 Column: i
LTC 40 MVAR Reac

Schedule Page: 426.1 Line No.: 19 Column: i
LTC 40 MVAR Reac

Schedule Page: 426.1 Line No.: 22 Column: i
20 MVAR Reac

Schedule Page: 426.1 Line No.: 23 Column: i
20 MVAR Reac

Schedule Page: 426.1 Line No.: 24 Column: i
20 MVAR Reac

Schedule Page: 426.1 Line No.: 25 Column: i
20 MVAR Reac

Schedule Page: 426.1 Line No.: 27 Column: i
90 MVAR Reac

Schedule Page: 426.1 Line No.: 28 Column: i
20 MVAR Reac

Schedule Page: 426.1 Line No.: 30 Column: i
20 MVAR Reac

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Customer Service	BHSC	Various	2,327,798
3	Transmission	BHSC	Various	10,923,035
4	Generation Dispatch & Power Marketing	BHSC	Various	1,265,913
5	General Accounting	BHSC	Various	2,461,328
6	Executive Management	BHSC	Various	1,480,911
7	FERC Tariff & Compliance	BHSC	Various	1,126,115
8	Regulatory & Governmental Affairs	BHSC	Various	2,444,301
9	Environmental Services	BHSC	Various	467,226
10	Finance & Treasury	BHSC	Various	1,055,287
11	Information Technology	BHSC	Various	8,921,172
12	Safety	BHSC	Various	407,642
13	Power delivery & Management	BHSC	Various	744,837
14	Human Resources	BHSC	Various	1,545,571
15	Communications	BHSC	Various	695,826
16	Organizational Development & Training	BHSC	Various	281,290
17	Internal Audit	BHSC	Various	423,324
18	Supply Chain Management	BHSC	Various	4,171,618
19	CPGS Plant Operations	BHSC	Various	1,339,822
20	**Non-power Goods or Services Provided for Affiliate**			
21	Neil SImpson Complex	CLFP	Various	7,523,183
22	Environmental Complex	CLFP	Various	87,960
23	Generation Dispatch & Power Marketing	CLFP	Various	19,769
24				
25	Non-power Goods or Services Provided by Affiliated			
26	Legal	BHSC	Various	4,754,675
27	Tax	BHSC	Various	871,199
28	Credit &Risk	BHSC	Various	307,795
29	Marketing & External Affairs	BHSC	Various	325,670
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42				

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) X An Original (2) __ A Resubmission	04/16/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 429 Line No.: 2 Column: d
Indirect charges were allocated based on Black Hills Service Company Allocation Manual.
Schedule Page: 429 Line No.: 3 Column: d
Indirect charges were allocated based on Black Hills Service Company Allocation Manual.
Schedule Page: 429 Line No.: 4 Column: d
Indirect charges were allocated based on Black Hills Service Company Allocation Manual.
Schedule Page: 429 Line No.: 5 Column: d
Indirect charges were allocated based on Black Hills Service Company Allocation Manual.
Schedule Page: 429 Line No.: 6 Column: d
Indirect charges were allocated based on Black Hills Service Company Allocation Manual.
Schedule Page: 429 Line No.: 7 Column: d
Indirect charges were allocated based on Black Hills Service Company Allocation Manual.
Schedule Page: 429 Line No.: 8 Column: d
Indirect charges were allocated based on Black Hills Service Company Allocation Manual.
Schedule Page: 429 Line No.: 9 Column: d
Indirect charges were allocated based on Black Hills Service Company Allocation Manual.
Schedule Page: 429 Line No.: 10 Column: d
Indirect charges were allocated based on Black Hills Service Company Allocation Manual.
Schedule Page: 429 Line No.: 11 Column: d
Indirect charges were allocated based on Black Hills Service Company Allocation Manual.
Schedule Page: 429 Line No.: 12 Column: d
Indirect charges were allocated based on Black Hills Service Company Allocation Manual.
Schedule Page: 429 Line No.: 13 Column: d
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Schedule Page: 429 Line No.: 14 Column: d
Indirect charges were allocated based on Black Hills Service Company Allocation Manual.
Schedule Page: 429 Line No.: 15 Column: d
Indirect charges were allocated based on Black Hills Service Company Allocation Manual.
Schedule Page: 429 Line No.: 16 Column: d
Indirect charges were allocated based on Black Hills Service Company Allocation Manual.
Schedule Page: 429 Line No.: 17 Column: d
Indirect charges were allocated based on Black Hills Service Company Allocation Manual.
Schedule Page: 429 Line No.: 18 Column: d
Indirect charges were allocated based on Black Hills Service Company Allocation Manual.
Schedule Page: 429 Line No.: 19 Column: d
Indirect charges were allocated based on Black Hills Service Company Allocation Manual.
Schedule Page: 429 Line No.: 21 Column: d
Costs were allocated based on generating capacity.
Schedule Page: 429 Line No.: 22 Column: d
Costs were allocated based on generating capacity.
Schedule Page: 429 Line No.: 23 Column: d
Costs were allocated based on generating capacity.
Schedule Page: 429 Line No.: 26 Column: d
Indirect charges were allocated based on Black Hills Service Company Allocation Manual.
Schedule Page: 429 Line No.: 27 Column: d
Indirect charges were allocated based on Black Hills Service Company Allocation Manual.
Schedule Page: 429 Line No.: 28 Column: d
Indirect charges were allocated based on Black Hills Service Company Allocation Manual.
Schedule Page: 429 Line No.: 29 Column: d
Indirect charges were allocated based on Black Hills Service Company Allocation Manual.

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