THIS FILING IS
Item 1: ☑ An Initial (Original) Submission OR ☐ Resubmission No.

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
Black Hills Power, Inc.	End of: 2021/ Q4

FERC FORM NO. 1 (REV. 02-04)

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, Licensees, and Others 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 Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

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.)

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

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 [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF 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. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

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/general-information-0/electric-industry-forms.

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 18th 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

e. The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions,

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, 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.

X. Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

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

thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current

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 by 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 shall 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

adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

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..."

FERC FORM NO. 1 (ED. 03-07)

"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

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
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: 2021/ 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 Mt Rushmore Rd, Rapid City, SD 57702	
05 Name of Contact Person Richard W. Kinzley	06 Title of Contact Person Senior Vice President and Chief Financial Officer
07 Address of Contact Person (Street, City, State, Zip Code) 7001 Mt. Rushmore Road, Rapid City, SD 57702	

08 Telephone of Contact Person, Including Area Code (605)721-2360	09 This Report is An Original / A Resubmission (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 04/15/2022

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 Richard W. Kinzley	03 Signature /s/ Richard W. Kinzley	04 Date Signed (Mo, Da, Yr) 04/15/2022
02 Title Senior Vice President and Chief Financial Officer		

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.

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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".

	Transmission Service and Generation Interconnection Study Costs		
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250	
31	Other Paid-in Capital	253	NA
32	Capital Stock Expense	254b	
33	Long-Term Debt	256	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262	
36	Accumulated Deferred Investment Tax Credits	266	NA
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	NA
39	Accumulated Deferred Income Taxes-Other Property	274	
40	Accumulated Deferred Income Taxes-Other	276	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300	
43	Regional Transmission Service Revenues (Account 457.1)	302	NA
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310	
46	Electric Operation and Maintenance Expenses	320	
47	Purchased Power	326	
48	Transmission of Electricity for Others	328	
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 (Account 403, 404, 405)	336	
53	Regulatory Commission Expenses	350	
54	Research, Development and Demonstration Activities	352	NA
55	Distribution of Salaries and Wages	354	
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	
61	**Electric Energy Account**	401a	
62	**Monthly Peaks and Output**	401b	
63	**Steam Electric Generating Plant Statistics**	402	
64	**Hydroelectric Generating Plant Statistics**	406	NA
65	**Pumped Storage Generating Plant Statistics**	408	NA
66	**Generating Plant Statistics Pages**	410	
0	**Energy Storage Operations (Large Plants)**	414	
67	**Transmission Line Statistics Pages**	422	
68	**Transmission Lines Added During Year**	424	
69	**Substations**	426	
70	**Transactions with Associated (Affiliated) Companies**	429	
71	**Footnote Data**	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☐ Two copies will be submitted ☐ No annual report to stockholders is prepared		

FERC FORM No. 1 (ED. 12-96)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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 RdRapid 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.

State of Incorporation: SD

Date of Incorporation: 1941-08-27

Incorporated Under Special Law:

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.

(a) Name of Receiver or Trustee Holding Property of the Respondent: N/A

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

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

(2) ☑ No

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent 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 beneficiaries for whom trust was maintained, and purpose of the trust.

Respondent is a wholly-owned, direct subsidiary of Black Hills Corporation. At December 31, 2021, Black Hills Corporation owned 100% of the common stock of Respondent.

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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			

FERC FORM No. 1 (ED. 12-96)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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)	Date Started in Period (d)	Date Ended in Period (e)
1	President & Chief Executive Officer	Linden R. Evans	825,000		
2	Sr. Vice President and Chief Financial Officer	Richard W. Kinzley	454,000		
3	Sr. Vice President and General Counsel	Brian G. Iverson	400,000		
4	Sr. Vice President - Chief Human Resources Officer	Jennifer C. Landis	316,000		
5	Sr. Vice President - Utility Operations	Stuart A. Wevik	425,000		
6	Sr. Vice President - Chief Information Officer	Erik D. Keller	340,000		
7	Sr. Vice President - Strategic Initiatives	(a) Scott A. Buchholz	340,000		
8	Vice President - BHE South Dakota	Marc Eyre	188,700		

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: OfficerName
Scott Buchholz retired effective March 8, 2021

FERC FORM No. 1 (ED. 12-96)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	Linden R. Evans (President and CEO)	Black Hills Corporation7001 Mt. Rushmore Rd.Rapid City, SD 57702	false	false
2	Richard W. Kinzley (Sr. Vice President and CFO)	Black Hills Corporation7001 Mt. Rushmore Rd.Rapid City, SD 57702	false	false
3	Brian G. Iverson (Sr. Vice President and General Counsel)	Black Hills Corporation7001 Mt. Rushmore Rd.Rapid City, SD 57702	false	false

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	☑ 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 (a)	FERC Proceeding (b)
1	BHP JOATT, Attachment H	ER18-1583-000
2	BHP JOATT, Schedule 2	ER15-2366-000

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 ☑ No (Checked by default - Not explicitly defined)

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

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					

28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					

FERC FORM NO. 1 (NEW. 12-08)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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). (a)	Schedule (b)	Column (c)	Line No. (d)
1	207	Electric Plant in Service	g	[(a)] 99
2	219	Accumulated Provision for Depreciation	c	[(b)] 25
3	219	Accumulated Provision for Depreciation	c	[(c)] 28
4	275	Accumulated Deferred Income Taxes	k	[(d)] 9
5	336	Depreciation of Electric Plant	b	[(e)] 7
6	336	Depreciation of Electric Plant	b	[(f)] 10

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: LineNumberOfFormulaRateVariances

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.

(b) Concept: LineNumberOfFormulaRateVariances

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 the Depreciation Expense approved in the last FERC Formula rate review.

(c) Concept: LineNumberOfFormulaRateVariances

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 the Depreciation Expense approved in the last FERC Formula rate review.

(d) Concept: LineNumberOfFormulaRateVariances

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.

(e) Concept: LineNumberOfFormulaRateVariances

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.

(f) Concept: LineNumberOfFormulaRateVariances

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.

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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 Pages 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.

1.None

2.None

3.None

4.None

5.None

6.None

7.None

8.The average BHP union wage increase for 2021 was 3%, the average non-union wage increase was 3.17%.

9.None

10.None

12.None

13. The following Director and Officer changes occurred in the year:

a. Scott A. Buchholz, Senior Vice President - Strategic Initiatives, retired effective March 8, 2021
b. Esther J. Newbrough, Vice President and Chief Risk Officer, retired effective April 1, 2021
c. Kyle D. White, Vice President - Regulatory Strategy, retired effective May 1, 2021
d. Thomas Stevens was appointed Vice President - Regulatory effective June 28, 2021
e. Marne M. Jones' title changed from Vice President - Regulatory and Finance to Vice President - Electric Utilities effective July 26, 2021
f. Nick Gardner's title changed from Vice President - Electric Utilities to Vice President - Natural Gas Utilities which removed him as an officer effective July 26, 2021
g. Todd Jacobs was appointed Vice President - Growth and Strategy effective July 26, 2021
h. Mark L. Lux's title changed from Vice President - Asset Optimization to Vice President - Power Delivery effective July 26, 2021
i. Marc Ostrem's title changed from Vice President - Mine Operations and Power Delivery to Vice President - Mine Operations and Generation effective July 26, 2021

14.None

FERC FORM No. 1 (ED. 12-96)

Page 108-109

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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	1,623,661,662	1,569,575,577
3	Construction Work in Progress (107)	200	42,909,812	35,881,998
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		1,666,571,474	1,605,457,575
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	472,885,939	452,451,971
6	Net Utility Plant (Enter Total of line 4 less 5)		1,193,685,535	1,153,005,604
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202		
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)			
10	Spent Nuclear Fuel (120.4)			
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202		
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)			
14	Net Utility Plant (Enter Total of lines 6 and 13)		1,193,685,535	1,153,005,604
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)			
19	(Less) Accum. Prov. for Depr. and Amort. (122)			
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224		
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		702,691	681,808
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		2,904,795	4,657,249
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)			

31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		3,607,486	5,339,057
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)			
36	Special Deposits (132-134)			
37	Working Fund (135)		4,966	4,966
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		17,277,398	14,636,630
41	Other Accounts Receivable (143)		815,214	1,758,734
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		173,368	255,787
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		13,047,381	19,150,663
45	Fuel Stock (151)	227	806,103	1,041,059
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	26,383,932	27,059,500
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228		
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227	1,482,736	2,237,242
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		4,525,712	3,140,099
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)			
61	Accrued Utility Revenues (173)		12,919,048	11,337,700
62	Miscellaneous Current and Accrued Assets (174)		2,794,626	918,744
63	Derivative Instrument Assets (175)			1,064,770
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)			
65	Derivative Instrument Assets - Hedges (176)			

66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		79,883,748	82,094,320
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		2,250,294	2,383,184
70	Extraordinary Property Losses (182.1)	230a	0	
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	
72	Other Regulatory Assets (182.3)	232	77,669,873	71,898,812
73	Prelim. Survey and Investigation Charges (Electric) (183)			295,767
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)		149,288	
76	Clearing Accounts (184)		1,385,326	1,357,240
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	5,362,139	4,720,808
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		498,699	719,004
82	Accumulated Deferred Income Taxes (190)	234	37,459,191	37,982,694
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		124,774,810	119,357,509
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		1,401,951,579	1,359,796,490

FERC FORM No. 1 (REV. 12-03)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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	23,416,396	23,416,396
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)		42,076,811	42,076,811
7	Other Paid-In Capital (208-211)	253	0	
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b	2,501,882	2,501,882
11	Retained Earnings (215, 215.1, 216)	118	450,137,120	412,342,957
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	0	0
13	(Less) Reaquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(1,129,057)	(1,420,318)
16	Total Proprietary Capital (lines 2 through 15)		511,999,388	473,913,964
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	340,000,000	340,000,000
19	(Less) Reaquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256		
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		73,830	77,970
24	Total Long-Term Debt (lines 18 through 23)		339,926,170	339,922,030
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		13,496,506	13,802,349
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		405,521	414,905
29	Accumulated Provision for Pensions and Benefits (228.3)		7,956,930	12,615,935

30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)			143,949
32	Long-Term Portion of Derivative Instrument Liabilities			
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		783,606	759,964
35	Total Other Noncurrent Liabilities (lines 26 through 34)		22,642,563	27,737,102
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)			
38	Accounts Payable (232)		24,875,740	20,576,090
39	Notes Payable to Associated Companies (233)		172,792,358	170,996,488
40	Accounts Payable to Associated Companies (234)		38,755,426	40,159,833
41	Customer Deposits (235)		1,832,730	2,161,550
42	Taxes Accrued (236)	262	9,468,439	7,551,189
43	Interest Accrued (237)		4,666,261	4,654,225
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		1,150,998	1,058,414
48	Miscellaneous Current and Accrued Liabilities (242)		5,787,328	5,707,046
49	Obligations Under Capital Leases-Current (243)		317,923	316,852
50	Derivative Instrument Liabilities (244)			920,680
51	(Less) Long-Term Portion of Derivative Instrument Liabilities			
52	Derivative Instrument Liabilities - Hedges (245)			
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		259,647,203	254,102,367
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		7,850,512	6,883,941
57	Accumulated Deferred Investment Tax Credits (255)	266		
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	2,350,695	2,007,099
60	Other Regulatory Liabilities (254)	278	99,793,163	102,204,237
61	Unamortized Gain on Reaquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272		

63	Accum. Deferred Income Taxes-Other Property (282)		138,786,389	135,042,654
64	Accum. Deferred Income Taxes-Other (283)		18,955,496	17,983,096
65	Total Deferred Credits (lines 56 through 64)		267,736,255	264,121,027
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		1,401,951,579	1,359,796,490

FERC FORM No. 1 (REV. 12-03)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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 (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) 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) t 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

6. Do not report fourth quarter data in columns (e) and (f)
7. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
8. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
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 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 r 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 retai 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 proc revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense ac
12. If any notes appearing in the report to stockholders 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, incl 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 th

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)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Oth Utili Curr Year Dat (ir dolla (k)
1	UTILITY OPERATING INCOME										
2	Operating Revenues (400)	300	353,935,773	303,367,621			353,935,773	303,367,621			
3	Operating Expenses										
4	Operation Expenses (401)	320	188,445,145	141,693,409			188,445,145	141,693,409			
5	Maintenance Expenses (402)	320	22,216,920	22,087,069			22,216,920	22,087,069			
6	Depreciation Expense (403)	336	46,396,845	42,573,528			46,396,845	42,573,528			
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	33,115	2,167			33,115	2,167			
8		336	1,774,436	1,774,436			1,774,436	1,774,436			

	Amort. & Depl. of Utility Plant (404-405)										
9	Amort. of Utility Plant Acq. Adj. (406)	336	97,406	97,406			97,406	97,406			
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)										
11	Amort. of Conversion Expenses (407.2)										
12	Regulatory Debits (407.3)										
13	(Less) Regulatory Credits (407.4)										
14	Taxes Other Than Income Taxes (408.1)	262	11,217,067	10,880,795			11,217,067	10,880,795			
15	Income Taxes - Federal (409.1)	262	5,090,832	7,309,643			5,090,832	7,309,643			
16	Income Taxes - Other (409.1)	262									
17	Provision for Deferred Income Taxes (410.1)	234, 272	58,411,252	15,737,124			58,411,252	15,737,124			
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	57,965,249	17,747,661			57,965,249	17,747,661			
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)		25,877	1,686			25,877	1,686			

25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		275,743,646	224,409,602			275,743,646	224,409,602			
27	Net Util Oper Inc (Enter Tot line 2 less 25)		78,192,127	78,958,019			78,192,127	78,958,019			
28	Other Income and Deductions										
29	Other Income										
30	Nonutilty Operating Income										
31	Revenues From Merchandising, Jobbing and Contract Work (415)		520,366	714,514							
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		730,133	762,811							
33	Revenues From Nonutility Operations (417)		42,955	2,859							
34	(Less) Expenses of Nonutility Operations (417.1)		54,126	163,112							
35	Nonoperating Rental Income (418)										
36	Equity in Earnings of Subsidiary Companies (418.1)	119	0	0							
37	Interest and Dividend Income (419)		1,237,930	1,154,659							
38	Allowance for Other Funds Used During Construction (419.1)		(101)	(10,492)							
39	Miscellaneous Nonoperating Income (421)		1,109,269	318,265							
40	Gain on Disposition of Property (421.1)		10,211	233,547							
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		2,136,371	1,487,429							

42	Other Income Deductions										
43	Loss on Disposition of Property (421.2)										
44	Miscellaneous Amortization (425)										
45	Donations (426.1)		344,906	712,609							
46	Life Insurance (426.2)										
47	Penalties (426.3)		23,713	19							
48	Exp. for Certain Civic, Political & Related Activities (426.4)		64,651	59,449							
49	Other Deductions (426.5)		1,726,069	490,858							
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		2,159,339	1,262,935							
51	Taxes Applic. to Other Income and Deductions										
52	Taxes Other Than Income Taxes (408.2)	262	26,932	29,449							
53	Income Taxes-Federal (409.2)	262	3,568	42,586							
54	Income Taxes-Other (409.2)	262									
55	Provision for Deferred Inc. Taxes (410.2)	234, 272									
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272									
57	Investment Tax Credit Adj.-Net (411.5)										
58	(Less) Investment Tax Credits (420)										
59			30,500	72,035							

	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)											
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		(53,468)	152,459								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		20,213,000	20,222,493								
63	Amort. of Debt Disc. and Expense (428)		201,362	282,461								
64	Amortization of Loss on Reaquired Debt (428.1)		220,305	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)		6,444,785	5,698,766								
68	Other Interest Expense (431)		126,821	1,403								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		861,777	1,301,343								
70	Net Interest Charges (Total of lines 62 thru 69)		26,344,496	25,173,568								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		51,794,163	53,936,910								
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									
77	Extraordinary Items After Taxes (line 75 less line 76)										
78	Net Income (Total of line 71 and 77)		51,794,163	53,936,910							

FERC FORM No. 1 (REV. 02-04)

Page 114-117

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, 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 for 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 for 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, attach them at page 122.

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		412,342,957	389,425,722
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1	Adjustments to Retained Earnings Credit			
4.2				
4.3				
4.4				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
10.1	Adjustments to Retained Earnings Debit			
10.2	Cumulative effect of ASU 2018-19, CECL adoption			(19,675)
10.3	Dividend to Parent		(14,000,000)	(31,000,000)
15	TOTAL Debits to Retained Earnings (Acct. 439)		(14,000,000)	(31,019,675)
16	Balance Transferred from Income (Account 433 less Account 418.1)		51,794,163	53,936,910
17	Appropriations of Retained Earnings (Acct. 436)			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
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)		450,137,120	412,342,957
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
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)		450,137,120	412,342,957
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		0	
50	Equity in Earnings for Year (Credit) (Account 418.1)		0	0
51	(Less) Dividends Received (Debit)		0	0
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
52.1	Other changes - explain		0	0
53	Balance-End of Year (Total lines 49 thru 52)		0	0

FERC FORM No. 1 (REV. 02-04)

Page 118-119

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 Instructions 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)	51,794,163	53,936,910
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	46,455,837	42,577,381
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of utility plant	1,774,436	1,774,436
5.2	Amortization of plant acq adjustments	97,406	97,406
8	Deferred Income Taxes (Net)	446,003	(2,010,537)
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	2,948,238	(8,709,095)
11	Net (Increase) Decrease in Inventory	1,665,030	(3,306,478)
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	3,774,279	(3,419,090)
14	Net (Increase) Decrease in Other Regulatory Assets	(12,661,050)	(1,242,181)
15	Net Increase (Decrease) in Other Regulatory Liabilities		
16	(Less) Allowance for Other Funds Used During Construction	(101)	(10,492)
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	Other (provide details in footnote):		
18.2	Bad debt expense	329,952	691,929
18.3	Deferred financing cost amortization	421,667	552,249
18.4	Employee benefit plan expense	785,023	1,297,615
18.5	Contributions to defined benefit pension plan		(1,739,000)
18.6	Mark-to-Market (gain) loss on derivative asset	144,090	(144,090)
18.7	Change in regulatory assets and liabilities impacting income statement	3,370,488	3,158,629

18.8	Changes in other current and non-current assets	(4,321,412)	(3,254,965)
18.9	Changes in other current and non-current liabilities	6,472	(868,949)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	97,030,723	79,402,662
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(93,684,007)	(132,294,280)
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	861,777	1,301,343
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
31.2	Cost of removal net of salvage	8,055,785	188,786
31.3	Other investments	1,731,571	(259,687)
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(84,758,428)	(133,666,524)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
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	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
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):		
53.1	Other (provide details in footnote):		
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(84,758,428)	(133,666,524)
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):		
64.1	Other (provide details in footnote):		
64.2	Cash distribution to member		
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
67.1	Other (provide details in footnote):		
67.2	Net borrowing of notes payable to Parent	34,400,000	55,000,000
67.3	Net borrowings from Money Pool		33,117,862
70	Cash Provided by Outside Sources (Total 61 thru 69)	34,400,000	88,117,862
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):		
76.1	Other (provide details in footnote):		
76.2	Dividend paid to Parent	(14,000,000)	(31,000,000)
76.3	Net payments to Money Pool	(32,672,295)	
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock		
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	(12,272,295)	54,262,862
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)		(1,000)
88	Cash and Cash Equivalents at Beginning of Period	4,966	5,966
90	Cash and Cash Equivalents at End of Period	4,966	4,966

FERC FORM No. 1 (ED. 12-96)

Page 120-121

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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.

(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.

Financial Statement Presentation and Basis of Accounting

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.
- For FERC reporting, regulatory assets and liabilities are classified as noncurrent deferred debits and credits, respectively, while GAAP classifies regulatory assets and liabilities as current and noncurrent.
- 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 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, 2021, 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, 2021 and 2020, we have no cash equivalents.

Revenue Recognition

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 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 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 in Note 2 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 below.

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 beginning of year	Additions charged to costs and expenses	Recoveries and Other Additions	Write-offs and Other Deductions	Balance at end of year
	(in thousands)				
Allowance for credit losses (Account 144):					
2021	$ 256	$ 330	$ 316	$ (729)	$ 173
2020	$ 160	$ 693	$ 1,652	$ (2,249)	$ 256

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, 2021 and 2020, we had total regulatory assets of $78 million and $72 million respectively, and total regulatory liabilities of $100 million and $102 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.

Third parties reimburse the us for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs (CIAC) are recorded as a reduction to Property, plant, and equipment 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, 2021 and 2020.

Depreciation provisions for regulated electric property, plant and equipment are computed on a straight-line basis using an annual composite rate of 2.3% in 2021 and 2.2% in 2020.

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.

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. See Note 10 for more information.

As of December 31, 2021, we had no outstanding derivatives on the Balance Sheet.

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:

<u>Level 1</u> — 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.

<u>Level 2</u> — 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.

<u>Level 3</u> — 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.

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.

Recently Issued Accounting Standards

<u>Facilitation of the Effects of Reference Rate Reform on Financial Reporting, ASU 2020-04</u>

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.

(2) REVENUE

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,	
	2021	2020
	(in thousands)	
<u>Customer types:</u>		
Retail	$ 236,218	203,452

Retail	$	236,218	203,452
Wholesale		34,887	31,814
Market - off-system sales		31,685	15,655
Transmission/Other		51,472	53,103
Revenue from contracts with customers		354,262	304,024
Other revenues		237	204
Total revenues	$	354,499	304,228
Timing of revenue recognition:			
Services transferred over time	$	354,262	304,024
Revenue from contracts with customers	$	354,262	304,024

(3) PROPERTY PLANT AND EQUIPMENT

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

	FERC Accounts	2021	2021 Weighted Average Useful Life (in years)	2020	2020 Weighted Average Useful Life (in years)	Lives (in years) Minimum	Lives (in years) Maximum
Electric plant:							
Production		$ 687,132	45	$ 664,374	43	25	61
Transmission		255,127	50	241,401	50	42	60
Distribution		487,693	45	473,031	45	21	62
Plant acquisition adjustment [(a)]		4,870	32	4,870	32	32	32
General		172,287	28	169,324	28	3	40
Operating lease assets		16,553		16,576			
Total plant-in-service	101-106,114	1,623,662		1,569,576			
Construction work in progress	107	42,910		35,882			
Total electric plant		1,666,572		1,605,458			
Less accumulated depreciation and amortization	108,110,111,115	(472,886)		(452,452)			
Electric plant net of accumulated depreciation and amortization		$ 1,193,686		$ 1,153,006			

(a) The plant acquisition adjustment is included in rate base and is being recovered with 10 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, a 402.3 MW mine-mouth coal-fired electric generating station located at the Gillette, Wyoming energy complex. 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 its additions, replacements and operating and maintenance expenses.

Transmission Tie

We jointly operate an electric transmission system, referred to as the Common Use System, with Basin Electric Power Cooperative and Powder River Energy Corporation. Each participant in the Common Use System individually owns assets that are operated together for a single system. The Common Use System also provides transmission service to our transmission tie.

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, a 116 MW mine-mouth, coal-fired power plant located at the Gillette, Wyoming energy complex. 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

Cheyenne Prairie, a 140 MW natural-gas fired power generation facility, was placed into commercial operations on October 1, 2014. The facility includes one combined-cycle 100 MW unit that we jointly own with Wyoming Electric, our related party operating in the Cheyenne, Wyoming area. We own 58 MW, and Wyoming Electric owns 42 MW of this combined-cycle unit. Cheyenne Prairie also includes one simple-cycle 40 MW combustion turbine that Wyoming Electric wholly owns. Black Hills Service Company (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. BHSC is responsible for operations of the wind farm.

As of December 31, 2021, 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	Less Accumulated Depreciation	Plant Net of Accumulated Depreciation
Wyodak Plant	$ 118,637	$ 882	$ (70,468)	$ 49,051
Transmission Tie	$ 24,544	$ 287	$ (6,922)	$ 17,909
Wygen III	$ 142,199	$ 635	$ (26,598)	$ 116,236
Cheyenne Prairie	$ 105,610	$ 50	$ (19,149)	$ 86,511
Corriedale	$ 48,888	$ —	$ (2,311)	$ 46,577

(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, 2021	December 31, 2021	December 31, 2020
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			(74)	(78)
Total Long-term Debt			$ 339,926	$ 339,922

Amortization of Deferred Financing Costs

Net deferred financing costs of approximately $2.3 million and $2.4 million were recorded on the accompanying Balance Sheets in Deferred Debits - Unamortized Debt Expenses (181) at December 31, 2021 and 2020, respectively, and are being amortized over the term of the debt. Amortization of deferred financing costs of approximately $0.2 million for the years ended December 31, 2021 and 2020 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, 2021.

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):

2022	$ —
2023	$ —
2024	$ —
2025	$ —
2026	$ —
Thereafter	$ 340,000

(6) FAIR VALUE MEASUREMENTS

Recurring Fair Value Measurements

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, Money pool notes payable and Notes payable to Parent approximate fair value due to their liquid or short-term nature. Cash is 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):

	2021		2020	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt [(a)]	$ 339,926	$ 469,777	$ 339,922	$ 504,374

(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):

	2021	2020
Regulatory assets		
Winter Storm Uri [(a)]	8,826	—
Deferred energy and fuel cost adjustments [(b)]	28,352	24,519
Deferred taxes on AFUDC [(c)]	4,438	4,650
Employee benefit plans [(d)]	14,890	19,244
Deferred taxes on flow through accounting [(b)]	14,117	11,943
Decommissioning costs [(c)]	2,662	4,436
Vegetation management [(b)]	3,455	5,759
Other regulatory assets [(b)]	930	1,348
Total Other Regulatory Assets (182.3)	77,670	71,899
Regulatory liabilities		
Employee benefit plans and related deferred taxes [(d)]	4,996	6,220
Excess deferred income taxes [(d)]	93,488	95,109
Other regulatory liabilities [(d)]	1,309	875
Total Other Regulatory Liabilities (254)	99,793	102,204

(a) In May 2021, we received approval from the South Dakota Public Utilities Commission (SDPUC) to recover costs from customers. See additional discussion below.
(b) Recovery of costs but we are not allowed a rate of return.
(c) In addition to recovery of costs, we are allowed a rate of return.
(d) 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.

Winter Storm Uri - See discussion below for Winter Storm Uri regulatory asset information.

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 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

Winter Storm Uri

In February 2021, a prolonged period of historic cold temperatures across the central United States, which covered all of our service territories, caused a substantial increase in heating and energy demand and contributed to unforeseeable and unprecedented market prices for natural gas and electricity. As a result of Winter Storm Uri, we incurred significant incremental fuel, purchased power and natural gas costs.

In May 2021, we received approval (Docket EL21-016) from the SDPUC to recover approximately $20 million of incremental and carrying costs from Winter Storm Uri from our South Dakota customers over a one-year period effective June 1, 2021. Additionally, we are recovering approximately $2.2 million of Winter Storm Uri incremental costs from our Wyoming customers through our existing regulatory mechanism. For the year ended December 31, 2021, we have collected $11 million of Winter Storm Uri incremental costs and carrying costs from customers.

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, 2021, the annual revenue requirement was $26 million and included estimated weighted average capital additions of $5 million for 2020 and 2021 combined.

(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 28 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 4.4% as of December 31, 2021).

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

	Income Statement Location	2021	2020
Operating lease cost	Operating Expenses (401)	$ 934	$ 929
Variable lease cost	Operating Expenses (401)	153	173
Total lease cost		$ 1,087	$ 1,102

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

	Balance Sheet Location	As of December 31, 2021	As of December 31, 2020
Assets:			
Operating leases	Utility Plant (101-106, 114)	$ 16,553	$ 16,576
Operating leases	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	(2,761)	(2,472)
Total lease assets		$ 13,792	$ 14,104
Liabilities:			
Operating leases	Obligations Under Capital Leases - Noncurrent (227)	$ 13,496	$ 13,802
Operating leases	Obligations Under Capital Leases - Current (243)	318	317
Total lease liabilities		$ 13,814	$ 14,119

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

	2021	2020
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 924	$ 922
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases	$ —	$ 23

	As of December 31, 2021	As of December 31, 2020
Weighted average remaining lease term (years):		
Operating leases	28 years	29 years
Weighted average discount rate:		
Operating leases	4.4 %	4.4 %

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

	Total
2022	$ 912
2023	909
2024	907
2025	852
2026	852
Thereafter	19,442
Total lease payments	$ 23,874
Less imputed interest	10,060
Present value of lease liabilities	$ 13,814

(9) INCOME TAXES

Income Tax Expense

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

	2021	2020
Current income tax expense (Accounts 409.1 and 409.2)	$ 5,094	$ 7,352
Deferred income tax (benefit) (Accounts 410.1 and 411.1)	446	(2,010)
Total income tax expense (benefit)	$ 5,540	$ 5,342

Effective Tax Rates

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

	2021	2020
Federal statutory rate	21.0 %	21.0 %
Amortization of excess deferred income tax expense [(a)]	(3.0)%	(6.3)%
Flow-through adjustments [(b)]	(2.3)%	(2.4)%
Tax credits [(c)] [(d)]	(6.8)%	(4.4)%
Uncertain tax benefits	0.2 %	1.3 %
Other	0.5 %	(0.1)%
Effective tax rate	9.7 %	9.0 %

(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):

	2021	2020
Deferred tax assets:		
Regulatory liabilities	$ 23,243	$ 24,920
Accumulated depreciation and other plant-related differences	1,923	2,219
Employee benefit plans	1,821	1,721
Credit Carryovers	7,093	3,436
Other	3,379	5,687
Total deferred tax assets (Account 190)	$ 37,459	$ 37,983
Deferred tax liabilities:		
Regulatory assets	(9,075)	(7,313)
Accelerated depreciation and other plant related differences	$ (135,164)	$ (129,644)
Employee benefit plans	(3,248)	(3,196)
Deferred energy costs	(6,973)	(7,923)
Other	(3,282)	(4,950)
Total deferred tax liabilities (Accounts 282 and 283)	$ (157,742)	$ (153,026)
Net deferred tax assets (liabilities)	$ (120,283)	$ (115,043)

Winter Storm Uri costs, which will be deductible in our 2021 tax return, created a net deferred tax liability of approximately $4.4 million. The deferred tax liability will reverse with the same timing as the costs are recovered from our customers.

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):

	2021	2020
Unrecognized tax benefits at January 1	$ 916	$ 216
Additions for prior year tax positions	156	181
Additions for current year tax positions	(42)	616
Reductions for temporary unrecognized tax benefits	(158)	—
Reductions for prior year tax positions	—	(97)
Unrecognized tax benefits at December 31	$ 872	$ 916

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, 2021 and 2020, 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, 2022.

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	2021	2020
Protected		
FERC	$ 13.5	$ 13.3
State	68.5	67.9
Total protected	$ 82.0	$ 81.2

Unprotected		
FERC	$ 1.9	$ 2.3
State	9.6	11.6
Total unprotected	$ 11.5	$ 13.9
Total excess deferred income tax liabilities (account 254)	$ 93.5	$ 95.1

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, 2021, the estimated amortization period based on regulatory orders, and the accounts where the adjustments and amortization were reported are reflected below (in millions):

		Accounts								
Jurisdiction	December 31, 2020	190	236	254 Other	282	283	411 Amort.	409-411	December 31, 2021	Amortization Period
Protected										
FERC	$ 13.3	$ 0.1	$ —	$ 0.4	$ —	$ —	$ (0.3)	$ —	$ 13.5	(a)
State	67.9	0.1	—	2.0	—	—	(1.5)	—	68.5	(a)
Total protected	$ 81.2	$ 0.2	$ —	$ 2.4	$ —	$ —	$ (1.8)	$ —	$ 82.0	
Unprotected										
FERC	2.3	$ (0.1)	$ —	$ (0.4)	$ —	$ —	$ 0.1	$ —	$ 1.9	(b)
State	11.6	(0.4)	—	(2.0)	—	—	0.4	—	9.6	(b)
Total unprotected	$ 13.9	$ (0.5)	$ —	$ (2.4)	$ —	$ —	$ 0.5	$ —	$ 11.5	
Total excess deferred income tax liabilities (account 254)	$ 95.1	$ (0.3)	$ —	$ —	$ —	$ —	$ (1.3)	$ —	$ 93.5	

(a) The weighted average amortization period was estimated at 55-75 years under ARAM.
(b) The weighted average amortization period was estimated at 55-75 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	
		2021	2020
Gains and Losses on cash flow hedges:			
Interest rate swaps gain (loss)	Misc Non Operating Income (421)	(65)	(64)
Income tax	Income Taxes Federal (409)	14	13
Total reclassification adjustments related to cash flow hedges, net of tax		(51)	(51)
Amortization of defined benefit plans:			
Actuarial gain (loss)	Misc Non Operating Income (421)	(162)	(125)
Income tax	Income Taxes Federal (409)	34	26
Total reclassification adjustments related to defined benefit plans, net of tax		(128)	(99)

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, 2020	$ (517)	$ (903)	$ (1,420)
Other comprehensive income (loss) before reclassifications	—	112	112
Amounts reclassified from AOCI	51	128	179
As of December 31, 2021	$ (466)	$ (663)	$ (1,129)
	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)

(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, 2021, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 22% to 30% return-seeking assets and 70% to 78% 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:

	2021	2020
Equity securities	15 %	21 %
Real estate	7 %	3 %
Fixed income funds	74 %	69 %
Cash and cash equivalents	1 %	3 %
Hedge funds	3 %	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):

	2021	2020
Defined Contribution Plans		
Company Retirement Contribution	$ 1,006	$ 960
Matching Contributions	$ 1,345	$ 1,328
Defined Benefit Plans		
Defined Benefit Pension Plan	$ —	$ 1,739
Non-Pension Defined Benefit Postretirement Healthcare Plan	$ 629	$ 620
Supplemental Non-qualified Defined Benefit Plan	$ 321	$ 321

While we do not have required 2022 contributions, we currently expect to contribute $0.5 million 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, 2021**					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV [(a)]	Total
Common Collective Trust - Cash and Cash Equivalents	$ —	$ 782	$ —	$ 782	$ —	$ 782
Common Collective Trust - Equity	—	9,146	—	9,146	—	9,146
Common Collective Trust - Fixed Income	—	44,157	—	44,157	—	44,157
Common Collective Trust - Real Estate	—	—	—	—	3,958	3,958
Hedge Funds	—	—	—	—	1,626	1,626
Total investments measured at fair value	$ —	$ 54,085	$ —	$ 54,085	$ 5,584	$ 59,669

Pension Plan	**December 31, 2020**					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV [(a)]	Total Fair Value
Common Collective Trust - Cash and Cash Equivalent	—	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

(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,	2021	2020	2021	2020	2021	2020
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 69,396	$ 67,061	$ 3,249	$ 3,246	$ 5,100	$ 5,176
Service cost	330	368	—	—	167	157
Interest cost	1,256	1,852	51	84	75	129
Plan Amendments	(133)	—	—	—	—	—
Actuarial (gain) loss	(4,325)	5,983	(142)	240	(286)	150
Benefits paid	(4,930)	(5,814)	(321)	(321)	(741)	(619)
Plan participants transfer to affiliate	(379)	(54)	—	—	23	—
Plan participants' contributions	—	—	—	—	110	107
Projected benefit obligation at end of year	$ 61,215	$ 69,396	$ 2,837	$ 3,249	$ 4,448	$ 5,100

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,	2021	2020	2021	2020	2021	2020
Beginning fair value of plan assets	$ 64,180	$ 60,190	$ —	$ —	$ —	$ —
Investment income (loss)	778	8,100	—	—	—	—
Benefits paid	—	1,739	(321)	(321)	631	513
Participant contributions	—	—	—	—	110	107
Employer contributions	(4,931)	(5,814)	321	321	(741)	(620)
Plan participants transfer to affiliate	(358)	(35)	—	—	—	
Ending fair value of plan assets	$ 59,669	$ 64,180	$ —	$ —	$ —	$ —

Amounts Recognized in the Balance Sheets

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
As of December 31,	2021	2020	2021	2020	2021	2020
Other Regulatory Assets (182.3)	$ 14,593	$ 18,928	$ —	$ —	$ —	$ —
Miscellaneous Current and Accrued Liabilities (242)	$ —	$ —	$ 320	$ 320	$ 554	$ 629
Accumulated Provision for Pensions and Benefits (228.3)	$ 1,545	$ 5,216	$ 2,518	$ 2,929	$ 3,894	$ 4,471
Other Regulatory Liabilities (254)	$ —	$ —	$ —	$ —	$ 1,117	$ 1,189

Accumulated Benefit Obligation

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
As of December 31,	2021	2020	2021	2020	2021	2020
Accumulated benefit obligation	$ 60,726	$ 67,579	$ 2,837	$ 3,249	$ 4,448	$ 5,100

Components of Net Periodic Expense

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
For the years ended December 31,	2021	2020	2021	2020	2021	2020
Service Cost	$ 330	$ 367	$ —	$ —	$ 167	$ 157
Interest Cost	1,256	1,852	52	84	75	129
Expected return on assets	(2,824)	(3,125)	—	—	—	—
Amortization of prior service cost (credits)	—	—	—	—	(335)	(335)
Recognized net actuarial loss (gain)	1,902	2,043	162	125	—	—
Net periodic expense	$ 664	$ 1,137	$ 214	$ 209	$ (93)	$ (49)

AOCI Amounts (After-Tax)

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
As of December 31,	2021	2020	2021	2020	2021	2020
Net (gain) loss	$ —	$ —	$ 663	$ 903	$ —	$ —
Total amounts included in AOCI, after-tax not yet recognized as components of net periodic expense	$ —	$ —	$ 663	$ 903	$ —	$ —

Assumptions

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2021	2020	2021	2020	2021	2020
Weighted-average assumptions used to determine benefit obligations:						
Discount rate	2.88 %	2.56 %	2.70 %	2.32 %	2.79 %	2.41 %
Rate of increase in compensation levels	3.08 %	3.34 %	N/A	N/A	N/A	N/A

Weighted-average assumptions used to determine net periodic benefit cost for plan year:						
Discount rate [(a)]	2.56 %	3.27 %	2.32 %	3.10 %	2.41 %	3.15 %
Expected long-term rate of return on assets [(b)]	4.50 %	5.25 %	N/A	N/A	1.80 %	2.35 %
Rate of increase in compensation levels	3.34 %	3.49 %	N/A	N/A	N/A	N/A

(a) The estimated discount rate for the Defined Benefit Pension Plan is 2.88% for the calculation of the 2022 net periodic pension costs.
(b) The expected rate of return on plan assets is 4.25% for the calculation of the 2022 net periodic pension cost.

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

	2021	2020
Trend Rate - Medical		
Pre-65 for next year - All Plans	6.05 %	6.10 %
Pre-65 Ultimate trend rate	4.50 %	4.50 %
Trend Year	2030	2027
Post-65 for next year - All Plans	5.10 %	4.92 %
Post-65 Ultimate trend rate	4.50 %	4.50 %
Trend Year	2030	2029

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
2022	$ 3,837	$ 320	$ 554
2023	$ 3,935	$ 315	$ 490
2024	$ 3,964	$ 310	$ 439
2025	$ 3,938	$ 280	$ 418
2026	$ 3,908	$ 241	$ 401
2027-2031	$ 18,867	$ 978	$ 1,646

(12) COMMITMENTS AND CONTINGENCIES

We have the following power purchase and transmission services agreements, not including related party agreements, as of December 31, 2021 (see Note 13 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 providing the ability to deliver a maximum of 50 MW of capacity and associated energy.
(b) This agreement relates to a new solar facility currently being constructed and will expire 20 years after construction completion, which is expected by the end of 2022.

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

Contract Type	Counterparty	Fuel Type	2021	2020
PPA	PacifiCorp	Coal	$ 8,923	$ 5,897
TSA	PacifiCorp	N/A	$ 1,783	$ 1,776
PPA	Platte River Power Authority	Wind	$ 596	$ 715

Future Contractual Obligations

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

	Minimum Payments required [(a)]
2022	$ 6,438
2023	$ 6,203
2024	$ —
2025	$ —
2026	$ —
Thereafter	$ —

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

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

We paid dividends to our Parent of $14 million and $31 million in 2021 and 2020, respectively.

Money Pool 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 0.48% at December 31, 2021

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

	2021	2020
Money pool notes payable -- Notes Payable to Associated Companies (233)	$ 58,031	$ 90,703
Money pool interest payable -- Notes Payable to Associated Companies (233)	$ 19	$ 32

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

	2021	2020
Money pool interest expense, net (Accounts 419 and 430)	$ 277	$ 645

Notes payable to Parent

We had the following Notes payable to Parent balances as of December 31 (in thousands):

	2021	2020
Notes payable to Parent -- Notes Payable to Associated Companies (233) [(a)]	$ 114,400	$ 80,000
Interest payable on borrowings from associated companies (233)	$ 361	$ 293

(a) The Notes Payable to Parent balance at December 31, 2021, includes the unpaid portion of a $24 million Note to pay for the unprecedented incremental costs from Winter Storm Uri in the first quarter of 2021. We began recovering Winter Storm Uri incremental costs and carrying costs from customers in June 2021 and subsequently paid down a portion of the Note. See additional information in Note 7.

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

	2021	2020
Notes payable to Parent interest expense -- Interest on Debt to Assoc. Companies (430)	$ 3,487	$ 2,171

Interest expense allocation from Parent

BHC provides daily liquidity and cash management on behalf of all its subsidiaries. For the years ended December 31, 2021, and 2020, we were allocated $2.8 million and $0.4 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 mine), 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 WRDC mine expiring in 2050 with three automatic renewal terms of 20 years each

- A Wygen III Ground Lease with WRDC mine expiring in 2050 with three automatic renewal terms of 20 years each.
- South Dakota Electric receives certain staffing and management services from BHSC for Cheyenne Prairie and Corriedale.

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:

	2021	2020
	(in thousands)	
Operating Revenues:		
Energy sold to Wyoming Electric	$ 2,574	$ 762
Rent from electric properties	$ 4,876	$ 3,957
Horizon Point shared facility revenue	$ 11,294	$ 11,360
Operating Expenses:		
Purchases from WRDC mine	$ 16,345	$ 16,863
Purchase of excess energy from Wyoming Electric	$ 1,996	$ 1,633
Purchase of renewable wind energy from Wyoming Electric - Happy Jack	$ 1,772	$ 2,266
Purchase of renewable wind energy from Wyoming Electric - Silver Sage	$ 3,160	$ 4,136
Gas transportation service agreement with Wyoming Electric for firm and interruptible gas transportation	$ 254	$ 311
Wygen III ground lease with WRDC mine	$ 1,016	$ 1,004

Related-party Corporate Support

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

	2021	2020
	(in thousands)	
Corporate support services and fees from Black Hills Service Company	$ 40,741	$ 45,299

(14) SUPPLEMENTAL CASH FLOW INFORMATION

Years ended December 31,	2021	2020
	(in thousands)	
Cash (paid) refunded during the period for:		
Interest (net of amounts capitalized)	$ (25,927)	$ (24,493)
Income taxes	$ 8,893	$ (21,813)
Non-cash investing and financing activities:		
Accrued property, plant and equipment purchases at December 31	$ 11,204	$ 12,202

(15) SUBSEQUENT EVENT

Except as described below, there have been no events subsequent to December 31, 2021 which would require recognition in the financial statements or disclosure.

Transmission Service Agreements

On January 1, 2022, South Dakota Electric entered into a firm point-to-point transmission service agreement with MEAN that provides a maximum of 20 MW of capacity and associated energy. This agreement expires December 31, 2023.

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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)	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 116, Line 78) (i)	Total Comprehens Income (j)
1	Balance of Account 219 at Beginning of Preceding Year		(812,731)			(567,514)		(1,380,245)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income		98,923			50,822		149,745		
3	Preceding Quarter/Year to Date Changes in Fair Value		(189,818)					(189,818)		
4	Total (lines 2 and 3)		(90,895)			50,822		(40,073)	53,936,910	53,896
5	Balance of Account 219 at End of Preceding Quarter/Year		(903,626)			(516,692)		(1,420,318)		
6	Balance of Account 219 at Beginning of Current Year		(903,626)			(516,692)		(1,420,318)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income		128,373			50,822		179,195		
8	Current Quarter/Year to Date Changes in Fair Value		112,066					112,066		
9	Total (lines 7 and 8)		240,439			50,822		291,261	51,794,163	52,085
10	Balance of Account 219 at End of Current Quarter/Year		(663,187)			(465,870)		(1,129,057)		

FERC FORM No. 1 (NEW 06-02)

Page 122 (a)(b)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	1,442,793,459	1,414,369,566		28,423,893			
4	Property Under Capital Leases	16,553,459	16,553,459					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	158,177,984	158,177,984					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	1,617,524,902	1,589,101,009		28,423,893			
9	Leased to Others							
10	Held for Future Use	1,266,452	1,266,452					
11	Construction Work in Progress	42,909,812	42,909,812					
12	Acquisition Adjustments	4,870,308	4,870,308					
13	Total Utility Plant (8 thru 12)	1,666,571,474	1,638,147,581		28,423,893			
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	472,885,939	468,778,546		4,107,393			
15	Net Utility Plant (13 less 14)	1,193,685,535	1,169,369,035		24,316,500			
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	468,877,355	464,769,962		4,107,393			
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20								

	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant							
22	Total in Service (18 thru 21)	468,877,355	464,769,962		4,107,393			
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	Amortization of Plant Acquisition Adjustment	4,008,584	4,008,584					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	472,885,939	468,778,546		4,107,393			

FERC FORM No. 1 (ED. 12-89)

Page 200-201

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
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)					

FERC FORM No. 1 (ED. 12-89)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 the 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) 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.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization						
3	(302) Franchise 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					233,606
9	(311) Structures and Improvements	47,270,877	4,966,329	172,794		(578,244)	51,486,168
10	(312) Boiler Plant Equipment	238,195,229	6,925,991	1,193,475	270,197	(1,878,626)	242,319,316
11	(313) Engines and Engine-Driven Generators	345,156					345,156
12	(314) Turbogenerator Units	120,145,634	8,563,550	1,134,229		(4,315,858)	123,259,097
13	(315) Accessory Electric Equipment	19,739,405	1,036,272	893			20,774,784
14	(316) Misc. Power Plant Equipment	3,149,686	346,608	77,202			3,419,092
15							

	(317) Asset Retirement Costs for Steam Production						
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	429,079,593	21,838,750	2,578,593	270,197	(6,772,728)	441,837,219
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					2,365,975
38	(341) Structures and Improvements	6,730,704	4,392,682	22,716		(95,809)	11,004,861
39		6,030,371	18,240			(14,068)	6,034,543

	(342) Fuel Holders, Products, and Accessories						
40	(343) Prime Movers	39,431	(39,431)				
41	(344) Generators	199,425,493	4,291,632	726,847		(1,219,100)	201,771,178
42	(345) Accessory Electric Equipment	19,385,024	2,796,154	96,502		(34,394)	22,050,282
43	(346) Misc. Power Plant Equipment	304,362	(5,017)				299,345
44	(347) Asset Retirement Costs for Other Production					756,044	756,044
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	234,281,360	11,454,260	846,065		(607,327)	244,282,228
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	663,360,953	33,293,010	3,424,658	270,197	(7,380,055)	686,119,447
47	3. Transmission Plant						
48	(350) Land and Land Rights	10,146,125	(41,026)				10,105,099
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	1,915,587	128,478				2,044,065
50	(353) Station Equipment	71,071,431	7,074,200	1,428,793	(5,158)	368,923	77,080,603
51	(354) Towers and Fixtures	955,668	(72,346)				883,322
52	(355) Poles and Fixtures	86,107,612	5,002,575	8,629		(16,979)	91,084,579
53	(356) Overhead Conductors and Devices	70,943,493	2,738,338			(13,821)	73,668,010
54	(357) Underground Conduit						
55	(358) Underground Conductors and Devices						
56	(359) Roads and Trails	6,920					6,920
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	241,146,836	14,830,219	1,437,422	(5,158)	338,123	254,872,598
59	4. Distribution Plant						
60	(360) Land and Land Rights	3,025,058	(126,341)		(77,816)		2,820,901
61	(361) Structures and Improvements	1,989,849	218,145	3,045		(93,570)	2,111,379
62	(362) Station Equipment	108,824,242	1,408,331	904,187	20,083	482,490	109,830,959
63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	113,672,713	4,016,430	6,554,133	(102,185)	8,903	111,041,728

65	(365) Overhead Conductors and Devices	68,390,302	5,526,240	3,779,294	(12,713)	154,626	70,279,161
66	(366) Underground Conduit	13,049,714	5,361,062	65,458	(100)	4,710	18,349,928
67	(367) Underground Conductors and Devices	59,640,708	3,968,549	359,653		(114,256)	63,135,348
68	(368) Line Transformers	49,838,887	6,751,571	977,202	10,525	(335,594)	55,288,187
69	(369) Services	39,524,418	(77,051)	825		(1,314)	39,445,228
70	(370) Meters	10,147,983	205,008	396,758	263,489		10,219,722
71	(371) Installations on Customer Premises	2,735,815	218,132	4,560		(753)	2,948,634
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	2,191,488	55,156	7,425		(16,946)	2,222,273
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	473,031,177	27,525,232	13,052,540	101,283	88,296	487,693,448
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		77,244			6,006,208
87	(390) Structures and Improvements	82,205,652	785,677	233,078	25,497		82,783,748
88	(391) Office Furniture and Equipment	17,787,007	549,341	1,169,939			17,166,409
89	(392) Transportation Equipment	19,713,594	1,866,307	1,225,730			20,354,171
90	(393) Stores Equipment	437,211	(78)		(270,197)		166,936

91	(394) Tools, Shop and Garage Equipment	3,489,659	32,438	37,984			3,484,113
92	(395) Laboratory Equipment	792,562	4,084	4,075			792,571
93	(396) Power Operated Equipment	4,273,519	1,048,413	72,851	(318,188)		4,930,893
94	(397) Communication Equipment	7,278,057	606,743	1,011,637	(10,932)		6,862,231
95	(398) Miscellaneous Equipment	1,236,222	78,555				1,314,777
96	SUBTOTAL (Enter Total of lines 86 thru 95)	143,296,935	4,971,480	3,832,538	(573,820)		143,862,057
97	(399) Other Tangible Property	16,576,394			(22,935)		16,553,459
98	(399.1) Asset Retirement Costs for General Plant						
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	159,873,329	4,971,480	3,832,538	(596,755)		160,415,516
100	TOTAL (Accounts 101 and 106)	1,537,412,295	80,619,941	21,747,158	(230,433)	(6,953,636)	1,589,101,009
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)	1,537,412,295	80,619,941	21,747,158	(230,433)	(6,953,636)	1,589,101,009

FERC FORM No. 1 (REV. 12-05)

Page 204-207

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
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					

FERC FORM No. 1 (ED. 12-95)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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	10/01/2014		45,126
3	Neil Simpson Station I - Land	10/01/2014		1,000
4	Osage Plant - Land	10/01/2014		149,038
5	St. Onge 230KV Substation - Land	07/01/2017	07/01/2022	254,255
6				
21	Other Property:			
22	Osage Plant - Water/Well Assets	10/01/2014		817,033
47	TOTAL			1,266,452

FERC FORM No. 1 (ED. 12-96)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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	HWY 85, Spearfish SD	1,285,200
2	New Portable Substation	2,615,284
3	DISTRIBUTION PLANT LESS THAN $1,000,000 EACH	6,587,228
4	GENERAL PLANT-ELECTRIC LESS THAN $1,000,000 EACH	1,621,104
5	OTHER GENERATION -PLANT LESS THAN $1,000,000 EACH	318,459
6	NSC North Ro System	1,120,554
7	Steam Plants DCS Loop Separation	1,370,968
8	NS 2 Aux Cooler Replacement	3,203,479
9	STEAM GENERATION LESS THAN $1,000,000 EACH	4,289,117
10	230kV Rebuilt Lange-Lookout	18,264,399
11	TRANSMISSION LESS THAN $1,000,000 EACH	2,234,020
43	Total	42,909,812

FERC FORM No. 1 (ED. 12-87)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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 12, column (c), and that reported for electric plant in service, page 204, column (d), 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.

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)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	446,568,013	446,568,013		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	42,588,190	42,588,190		
4	(403.1) Depreciation Expense for Asset Retirement Costs	33,115	33,115		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	731,492	731,492		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):	291,766	291,766		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	43,644,563	43,644,563		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(12,637,259)	(12,637,259)		
13	Cost of Removal	(3,499,905)	(3,499,905)		
14	Salvage (Credit)	8,083,226	8,083,226		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(8,053,938)	(8,053,938)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	(17,388,676)	(17,388,676)		
18	Book Cost or Asset Retirement Costs Retired		0		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	464,769,962	464,769,962		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	160,328,339	160,328,339		

21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	65,847,263	[(a)]65,847,263		
25	Transmission	46,518,661	46,518,661		
26	Distribution	159,225,441	159,225,441		
27	Regional Transmission and Market Operation				
28	General	32,850,258	32,850,258		
29	TOTAL (Enter Total of lines 20 thru 28)	464,769,962	464,769,962		

FERC FORM No. 1 (REV. 12-05)

FOOTNOTE DATA

(a) Concept: AccumulatedDepreciationOtherProduction

Amount includes an Asset Retirement Obligation of $35,282

FERC FORM No. 1 (REV. 12-05)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder 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.
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 from investments, including such revenues from 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 different 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.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	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)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								

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 $		Total		0			

FERC FORM No. 1 (ED. 12-89)

Page 224-225

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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)	1,041,059	806,103	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)	6,109,676	6,594,612	Trans & Dist
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	20,560,017	19,496,108	Production
8	Transmission Plant (Estimated)	20,816	21,348	Transmission
9	Distribution Plant (Estimated)	302,101	251,698	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	[(a)]66,890	[(b)]20,166	General
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	27,059,500	26,383,932	
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)	2,237,242	1,482,736	
17				
18				
19				
20	TOTAL Materials and Supplies	30,337,801	28,672,771	

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesOther

Operations and Maintenance expenses assigned to general.

(b) Concept: PlantMaterialsAndOperatingSuppliesOther

Operations and Maintenance expenses assigned to general.

FERC FORM No. 1 (REV. 12-05)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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.
6. Report on Line 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 acquired 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 and 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.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year		3,731		4,197		4,197		4,197		4,197		20,519
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)		1,411		1,411		1,411		1,411		38,097		43,741
5	Returned by EPA												
6													
7													
8	BHP to BHC General Account				(466)		(466)		(466)				(1,398)
9													
10													
11													
12													
13													
14													
15	Total				(466)		(466)		(466)				(1,398)
16													
17	Relinquished During Year:												
18	Charges to Account 509												
19	Other:												
20	Allowances Used												

20.1	Allowances Used		(945)		(945)		(945)		(945)				(3,780)
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year		4,197		4,197		4,197		4,197		42,294		59,082
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												

FERC FORM No. 1 (ED. 12-95)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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.
6. Report on Line 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 acquired 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 and 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.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year												
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
5	Returned by EPA												
6													
7													
8													
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509												
19	Other:												
20	Allowances Used												
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												

FERC FORM No. 1 (ED. 12-95)

Page 228(ab)-229(ab)b

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1	N/A					
20	TOTAL	0	0		0	0

FERC FORM No. 1 (ED. 12-88)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	N/A					
49	TOTAL	0	0		0	0

FERC FORM No. 1 (ED. 12-88)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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**				
2	Trans-Pln Stdys JT 230 kV	3,186	561.5		
20	Total	3,186			
21	**Generation Studies**				
22	Orion Renewable 30	33	561.7		
23	Orion Renewable 3	82	561.7		
24	BHBE G15 - 80 MW Solar	18,827	561.7		
39	Total	18,942			
40	Grand Total	22,128			

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 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	4,649,702	71,484	283	283,343	4,437,843
2	Deferred Transmission Cost	4,920,223	26,186,406	Various	25,495,585	5,611,044
3	[(a)] SD System Inspection	235,491		928	94,197	141,294
4	[(b)] SD Storm Atlas	718,408		588	287,363	431,045
5	[(c)] Rate Case Expenses	97,762		928	39,105	58,657
6	[(d)] Power Plant Decommissioning Costs	4,436,090		405	1,774,436	2,661,654
7	Pension	18,927,792		228	4,334,335	14,593,457
8	Deferred Taxes on Flow Through Accounting	11,942,796	2,746,378		572,343	14,116,831
9	Deferred Power Cost Adjustment	13,008,953	121,632,819	Various	118,749,776	15,891,996
10	Retiree Healthcare Plan	316,053	19,212	Various	38,424	296,841
11	Energy Cost Adjustment	6,589,514	45,827,640	Various	44,374,079	8,043,075
12	[(e)] Vegetation Management	5,758,790		593	2,303,516	3,455,274
13	Energy Efficiency	297,238	960,913	Various	959,536	298,615
14	Compensated Absences		307,117	Various	307,117	
15	[(f)] Winter Storm 2021		25,910,282	Various	18,278,035	7,632,247
44	TOTAL	71,898,812	223,662,251		217,891,190	77,669,873

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
SD System Inspection expected to be fully amortized in June 2023.Approved by the South Dakota Public Commission in Docket EL14-026.
(b) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
SD Storm Atlas expected to be fully amortized in June 2023.Approved by the South Dakota Public Utilities Commission in Docket EL14-026.
(c) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Rate Case Expenses expected to be fully amortized in June 2023.Approved by the South Dakota Public Utilities COmmission in Docket EL14-026.
(d) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Power Plant Decommissioning expected to be fully amortized in June 2023.Approved by the South Dakota Public Utilities Commission in Docket EL14-026.
(e) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Vegetation Management expected to be fully amortized in June 2023. Approved by the South Dakota Public Utilities Commission in Docket EL14-026.
(f) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Winter Storm 2021 expected to be fully amortized in May 2022. Approved by the South Dakota Public Utilities Commission in Docket EL21-016.

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	Tax Increment Financing (TIF) Receivable	4,091,626	209,856			4,301,482
2	Corriedale Spare Parts Consigned Inventory	199,647		548	23,488	176,159
3	Teckla-Osage Transmission Line Insurance Receivable	300,000				300,000
4	Misc Deferred Debits	129,535	936,072	Various	481,109	584,498
47	Miscellaneous Work in Progress					
48	Deferred Regulatroy Comm. Expenses (See pages 350 - 351)					
49	TOTAL	4,720,808				5,362,139

FERC FORM No. 1 (ED. 12-94)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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 at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Deferred Compensation	139,245	121,437
3	Retiree Healthcare Plan	1,413,726	1,168,626
4	Regulatory Liabilities	20,012,149	19,661,013
5	Pension	5,031,438	3,879,273
6	Bad Debt Reserve	927,942	905,404
7	Non-qualified Pension Plan	281,952	280,690
8	PEP AOCI	180,237	127,254
9	Line Extension Deposits	1,613,683	1,818,656
10	Abandonment Loss	1,451,151	(215,224)
11	Other	3,076,838	2,542,477
12	Operating Lease	2,965,032	2,901,030
13	Production Tax Credit	583,418	4,003,239
14	Bonus Compensation	305,883	265,316
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	37,982,694	37,459,191
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	0	0
17.1	Other (Specify)		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	37,982,694	37,459,191

Notes

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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.
3. Give 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 noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. 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 purpose of pledge.

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)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2	Common Stock	50,000,000	1.00		23,416,396	23,416,396				
7	Total	50,000,000			23,416,396	23,416,396				
8	Preferred Stock (Account 204)									
9										
10										
11										
12	Total									
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2										
3										
4										
5	Total									

FERC FORM NO. 1 (ED. 12-91)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2022-04-15	Year/Period of Report End of: 2021/ Q4

Other Paid-in Capital

1. 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 a total of all accounts for reconciliation with the balance sheet, page 112. 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 briefly explain the origin and purpose of each donation.
b. Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
c. Gain or 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 that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	
16	Ending Balance Amount	
17	**Historical Data - Other Paid in Capital**	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	0

FERC FORM No. 1 (ED. 12-87)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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
22	TOTAL	2,501,882

FERC FORM No. 1 (ED. 12-87)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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

1. Report by Balance Sheet Account the details concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances fr Long-Term Debt.
2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such companies from which advances were received, and in column (b) include the related account number.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column
5. In a supplemental statement, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, during year (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securitie
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column between the total of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)
1	Bonds (Account 221)									
2	2002 AE Bonds, 7.23%	Various	75,000,000		991,064			08/13/2002	08/15/2032	08/13/2002
3	2009 AF Bonds, 6.125%	Various	180,000,000		2,277,473		124,200	10/27/2009	11/01/2039	10/27/2009
4	2014 AG Bonds, 4.43%	Various	85,000,000		716,799			10/01/2014	10/20/2044	10/01/2014
5	Subtotal		340,000,000		3,985,336		124,200			
6	Reacquired Bonds (Account 222)									
7										
8										
9										
10	Subtotal									
11	Advances from Associated Companies (Account 223)									
12										
13										
14										
15	Subtotal									
16										

	Other Long Term Debt (Account 224)										
17											
18											
19											
20	Subtotal										
33	TOTAL		340,000,000								

FERC FORM No. 1 (ED. 12-96)

Page 256-257

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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)	51,794,163
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Derivative	144,090
9	Deductions Recorded on Books Not Deducted for Return	
10	Nondeductible federal income taxes	5,540,403
11	Employee Benefits	758,789
12	Other	2,258
13	Operating Lease	7,091
14	Interest Rate Swap	64,332
15	PUC Fees	13,830
16	Captive Insurance	355,207
17	Meals and Entertainment	1,269
18	Ref Asset Non Service	87,230
19	Required Bond Loss	220,305
20	Fines and Penalties	358,783
21	Club Dues	20,149
22	Lobbying	7,346
23	Misc	3
24	Income Recorded on Books Not Included in Return	
14	Income Recorded on Books Not Included in Return	
15	Deductions on Return Not Charged Against Book Income	
19	Deductions on Return Not Charged Against Book Income	
20	NOL Carry Forward	(12,754,481)
21	Other	
22	Winter Storm Uri	(7,632,247)

23	Employee Benefits	(1,034,958)
24	Deferred Revenue	(551,170)
25	Rate Refund	(143,949)
26	Prepaid Expenses	(895,486)
27	Bad Debt Reserve	(82,420)
28	NSC Pension Offset	(49,308)
29	Federal Tax Net Income	17,208,410
27	Federal Tax Net Income	3,613,766
28	Show Computation of Tax:	
29	Tax Return True Up Adjustment	(1,187,304)
30	FAS 109	2,667,937
31	Total	5,094,399

FERC FORM NO. 1 (ED. 12-96)

Page 261

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

TAXES ACCRUED, PREPAID AND CHARGES 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 durin 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 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 page is not affected by the inclusion of these taxes.
3. Include in column (g) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (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.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifyin
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a foot- note. Designate debit adjustments
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmit
8. Report in columns (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertair amounts charged to Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also showı 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.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR: Taxes Accrued (Account 236) (e)	BALANCE AT BEGINNING OF YEAR: Prepaid Taxes (Include in Account 165) (f)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR: Taxes Accrued (Account 236) (j)	BALANCE AT END OF YEAR: Prepaid Taxes (Included in Account 165) (k)	Elec (Acc 408 409. (l)
1	Unemployment				10,016	0	(169)	9,617		230	0	10
2	FICA				200,244	0	1,729,160	1,741,351		188,053	0	1,696
3	Income				0	0	5,094,401	3,621,032		1,473,369	0	5,090
4	**Subtotal Federal Tax**				210,260	0	6,823,392	5,372,000		1,661,652	0	6,798
5	WY Unemployment				3,855	0	37,754	41,606		3	0	96
6	**Subtotal State Tax**				3,855	0	37,754	41,606		3	0	96
7	SD Property				5,647,910	0	5,650,004	5,381,819		5,916,095	0	5,650
8	WY Property				1,172,784	0	2,736,557	2,732,297		1,177,044	0	2,736
9	MT Property				225,051	0	594,622	569,945		249,728	0	594
10	NE Property				177,927	0	168,183	201,481		144,629	0	168
11	**Subtotal Property Tax**				7,223,672	0	9,149,366	8,885,542		7,487,496	0	9,149
12	MT Regulatory Tax				0	0	60,168	60,168		0	0	60
13	Accrued Taxes Sales/Use-SD				99,022	0	581,732	608,541		72,213	0	137
14	Accrued Taxes WY				14,380	0	408,963	176,268		247,075	0	(6.
15	Accrued Franchise Tax				0	0	72,605	72,605		0	0	72
16					113,402	0	1,123,468	917,582		319,288	0	263

	Subtotal Miscellaneous Other Tax											
40	TOTAL				7,551,189	0	17,133,980	15,216,730		9,468,439	0	16,307

FERC FORM NO. 1 (ED. 12-96)

Page 262-263

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: TaxesIncurredOther
Allocation of payroll taxes to operating and maintenance expenses and capital assets
(b) Concept: TaxesIncurredOther
Allocation of payroll taxes to operating and maintenance expenses and capital assets
(c) Concept: TaxesIncurredOther
Sales tax capitalized or expensed.

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%									
3	4%									
4	7%									
5	10%									
8	TOTAL Electric (Enter Total of lines 2 thru 7)									
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										`
47	OTHER TOTAL									
48	GRAND TOTAL									

FERC FORM NO. 1 (ED. 12-89)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

OTHER DEFERRED 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		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Contractor Retainage	1,941,396	various	5,435,896	4,375,683	881,183
2	Deferred Revenue	1,140	various	1,195,813	1,194,673	
3	Other	64,563	242	65,197	696	62
4	Estimated Contract Liability		various		1,469,450	1,469,450
47	TOTAL	2,007,099		6,696,906	7,040,502	2,350,695

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities										
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)										
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	Other										
16.2	Other										
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										

FERC FORM NO. 1 (ED. 12-96)

Page 272-273

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

ACCUMULATED DEFERRED 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 accelerate amortization.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance a End of Yea (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 282										
2	Electric	135,042,654	27,812,495	25,618,879			182.3		182.3		137,236,27
3	Gas										
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	135,042,654	27,812,495	25,618,879			182.0	220,797	182.3	1,770,916	138,786,38
6											
7											
8											
9	TOTAL Account 282 (Total of Lines 5 thru 8)	135,042,654	27,812,495	25,618,879				220,797		1,770,916	138,786,38
10	Classification of TOTAL										
11	Federal Income Tax	135,042,654	27,812,495	25,618,879				220,797		1,770,916	138,786,38
12	State Income Tax										
13	Local Income Tax										

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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

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)	CHANGES DURING YEAR: Amounts Debited to Account 410.2 (e)	CHANGES DURING YEAR: Amounts Credited to Account 411.2 (f)	ADJUSTMENTS: Debits: Account Credited (g)	ADJUSTMENTS: Debits: Amount (h)	ADJUSTMENTS: Credits: Account Debited (i)	ADJUSTMENTS: Credits: Amount (j)	Balance at End of Year (k)
1	Account 283										
2	Electric										
3	Pension/Benefit	2,876,070	4,496	140,465							2,740,101
4	Reacquired Bond Loss	150,992		46,264							104,728
5	Flow Through	3,489,746					182	50,976	182.0	456,547	3,895,317
6	Derivative	30,259	1,089,066	1,132,835						13,510	
7	Other										
8	Deferred Costs	7,923,406	15,109,520	14,457,524							8,575,402
9	Plant Acquisition Adjustment	223,446		22,030							201,416
10	Operating Lease Asset	2,964,713	647	66,138							2,899,222
11	Prepaid Expenses	320,189	270,582	82,530							508,241
12	Excess Deferred Income Taxes		44,227	44,227							
13	Flow-Through Adjustments	9,607	20,298								29,905
14	State Income Tax Deduction	(11)	11								
15	AFUDC Equity	(5,321)					182	25,046	182.0	31,531	1,164
9	TOTAL Electric (Total of lines 3 thru 8)	17,983,096	16,538,847	15,992,013				76,022		501,588	18,955,496
10	Gas										
11	Other										
17	TOTAL Gas (Total of lines 11 thru 16)										

18	TOTAL Other										
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	17,983,096	16,538,847	15,992,013				76,022		501,588	18,955,496
20	Classification of TOTAL										
21	Federal Income Tax	17,983,096	16,538,847	15,992,013				76,022		501,588	18,955,496
22	State Income Tax										
23	Local Income Tax										

NOTES

FERC FORM NO. 1 (ED. 12-96)

Page 276-277

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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 (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Power Plant Maintenance	874,772	512		434,448	1,309,220
2	Excess Deferred Income Taxes	95,109,064	Various	6,297,403	4,676,321	93,487,982
3	Pension	5,031,438	Various	2,304,330	1,152,165	3,879,273
4	Retiree Healthcare Plan	1,188,963	228	72,275		1,116,688
41	TOTAL	102,204,237		8,674,008	6,262,934	99,793,163

FERC FORM NO. 1 (REV 02-04)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

Electric Operating Revenues

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.
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 page 108, 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.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	86,667,639	74,423,927	573,929	557,471	60,117	59,535
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	105,603,588	89,660,514	764,326	732,595	13,640	13,544
5	Large (or Ind.) (See Instr. 4)	39,815,739	34,686,078	457,951	443,403	25	25
6	(444) Public Street and Highway Lighting	1,221,183	1,243,730	10,179	10,239	220	214
7	(445) Other Sales to Public Authorities	2,473,858	2,110,574	23,068	21,549	148	149
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	235,782,007	202,124,823	1,829,453	1,765,257	74,150	73,467
11	(447) Sales for Resale	66,571,882	47,490,484	1,328,370	1,311,985	41	40
12	TOTAL Sales of Electricity	302,353,889	249,615,307	3,157,823	3,077,242	74,191	73,507
13	(Less) (449.1) Provision for Rate Refunds	503	(868,652)				
14	TOTAL Revenues Before Prov. for Refunds	302,353,386	250,483,959	3,157,823	3,077,242	74,191	73,507
15	Other Operating Revenues						
16		237,231	204,208				

	(450) Forfeited Discounts						
17	(451) Miscellaneous Service Revenues	436,570	458,043				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	17,484,195	17,422,342				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	993,900	628,934				
22	(456.1) Revenues from Transmission of Electricity of Others	32,430,491	34,170,135				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	51,582,387	52,883,662				
27	TOTAL Electric Operating Revenues	353,935,773	303,367,621				

Line12, column (b) includes $ 290,017 of unbilled revenues.
Line12, column (d) includes 4,046 MWH relating to unbilled revenues

FERC FORM NO. 1 (REV. 12-05)

Page 300-301

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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)
1	N/A				
46	TOTAL				

FERC FORM NO. 1 (NEW. 12-05)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	Regular Service - SD710	373,930	48,099,798	45,742	8,175	0.129
2	Regular Service - SD875	475	64,879	50	9,500	0.137
3	Regular Service - WY910	13,810	1,715,934	1,534	9,003	0.124
4	Regular Service - MT910	74	5,468	11	6,727	0.074
5	Total Electric - SD712	93,704	9,739,459	7,319	12,803	0.104
6	Total Electric - SD876	133	15,596	12	11,083	0.117
7	Total Electric - SD887	223	24,559	11	20,273	0.110
8	Total Electric - WY912	4,010	467,242	334	12,006	0.117
9	Total Electric - WY913	18	2,199	1	18,000	0.122
10	Total Electric - MT912	29	1,559	1	29,000	0.054
11	Demand Service - SD714	16,494	1,674,206	861	19,157	0.102
12	Demand Service - SD716	67,073	6,140,230	3,094	21,678	0.092
13	Demand Service - WY914	220	16,151	11	20,000	0.073
14	Demand Service - WY916	1,629	184,594	85	19,165	0.113
15	Utility Controlled - SD717	118	7,539	2	59,000	0.064
16	Rental - SD798					
17	Rental - SD799		1,880	31		
18	Rental - WY798		130	2		
19	Private Area Lighting - SDA24	771	117,235	949	812	0.152
20	Private Area Lighting - SDB24	20	4,153	9	2,222	0.208
21	Private Area Lighting - SDC24	1	93	2	500	0.093
22	Private Area Lighting - WYA24	42	7,851	56	750	0.187
23	Private Area Lighting - WYB24					
24	PGM		(26)			
25	Fuel Clause Accrual		18,260,909			

26	Residential Sales Billed	572,774	86,551,638	60,117	9,528	0.151
41	TOTAL Billed Residential Sales	1,155	116,001			0.100
42	TOTAL Unbilled Rev. (See Instr. 6)	573,929	86,667,639			0.151
43	TOTAL	573,929	86,667,639	60,117		

FERC FORM NO. 1 (ED. 12-95)

Page 304

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	General Service - SD718	744	79,489	47	15,830	0.107
2	General Service - SD720	351,868	44,678,940	10,467	33,617	0.127
3	General Service - SD770	1,676	270,099	113	14,832	0.161
4	General Service - SD826	11,305	1,130,774	30	376,833	0.100
5	General Service - SD878	780	102,674	14	55,714	0.132
6	General Service - SD890	331	45,605	1	331,000	0.138
7	General Service - WY918	27	3,392	3	9,000	0.126
8	General Service - WY920	23,256	2,905,968	474	49,063	0.125
9	General Service - MT920	146	17,655	22	6,636	0.121
10	Total Electric - SD723	34,892	3,840,392	800	43,615	0.110
11	Total Electric - WY923	1,062	119,406	38	27,947	0.112
12	Total Electric - MT923	9	779	2	4,500	0.087
13	General Service Large - SD721	82,966	8,087,160	87	953,632	0.097
14	General Service Large - SD771	27,944	1,917,013	1	27,944,000	0.069
15	General Service Large - SD731	37,209	2,848,530	6	6,201,500	0.077
16	General Service Large - SD827	168,903	14,359,364	108	1,563,917	0.085
17	General Service Large - WY921	2,287	230,640	3	762,333	0.101
18	Large DMD Curtailable - SD722	629	47,193	1	629,000	0.075
19	Energy Storage - SD755	8,960	653,450	25	358,400	0.073
20	Irrigation Pumping - SD726	1,080	137,174	25	43,200	0.127
21	Utility Controlled - SD727	1,819	123,949	13	139,923	0.068
22	Utility Controlled - SD750	212	18,124	2	106,000	0.085
23	Rental - SD798		2,585	4		
24	Rental - SD799		26,421	180		
25	Rental - WY798		986	12		

26	Private Area Lighting - SDA24	1,792	244,339	921	1,946	0.136
27	Private Area Lighting - SDB24	612	119,232	167	3,665	0.195
28	Private Area Lighting - SDC24	128	9,250	16	8,000	0.072
29	Private Area Lighting - WYA24	66	12,265	45	1,467	0.186
30	Private Area Lighting - WYB24	44	9,435	13	3,385	0.214
31	PGM		(26)			
32	Fuel Clause Accrual		21,573,666			
33	Renewable Ready		1,639,055			
34	Commercial Sales Billed	760,747	105,254,978	13,640	55,773	0.138
41	TOTAL Billed Small or Commercial	3,579	348,610			0.097
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	764,326	105,603,588			0.138
43	TOTAL Small or Commercial	764,326	105,603,588	13,640		

FERC FORM NO. 1 (ED. 12-95)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	General Service Large - SD720	259	27,882	1	259,000	0.108
2	General Service Large - SD721					
3	General Service Large - WY921	7,865	962,152	1	7,865,000	0.122
4	General Service Large - WY934	47,023	4,258,025	7	6,717,571	0.091
5	General Service Large - MT920	22	1,926	3	7,333	0.088
6	General Service Large - MT930	3,128	267,784	1	3,128,000	0.086
7	General Service Large - MT931	9,558	905,938	2	4,779,000	0.095
8	General Service Large - MT932	132,911	8,245,910	1	132,911,000	0.062
9	Large DMD Curtailable - N/A					
10	Industrial Contract Tran - SD761	108,480	5,929,190	1	108,480,000	0.055
11	Industrial Contract Serv - WY931	61,938	4,164,885	1	61,938,000	0.067
12	Forest Products Primary - SD764	27,093	1,903,939	1	27,093,000	0.070
13	Forest Products Primary - SD774	54,755	3,304,972	1	54,755,000	0.060
14	Forest Products Secondary - SD765	5,862	602,289	1	5,862,000	0.103
15	Rental - SD798					
16	Rental - SD799					
17	Rental - WY798		304	1		
18	Private Area Lighting - SDA24	2	312	1	2,000	0.156
19	Private Area Lighting - SDB24	2	484	1	2,000	0.242
20	Private Area Lighting - SDC24					
21	Private Area Lighting - WYA24					
22	Private Area Lighting - WYB24	12	2,567	1	12,000	0.214
23	Fuel Clause Accrual		7,908,716			
24	Renewable Ready		1,526,961			
41	TOTAL Billed Large (or Ind.)	458,910	40,014,236	25	18,356,400	0.087

	Sales					
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	(959)	(198,497)			0.207
43	TOTAL Large (or Ind.)	457,951	39,815,739	25	18,318,040	0.087

FERC FORM NO. 1 (ED. 12-95)

Page 304

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	Company Owned Service - SD840	2,849	601,035	35	81,400	0.211
2	Company Owned Service - WY940	246	65,185	1	246,000	0.265
3	Customer Owned Service - SD741	6,154	438,214	34	181,000	0.071
4	Customer Owned Service - SD841	110	11,051	6	18,333	0.100
5	Customer Owned Service - WY941	96	7,592	1	96,000	0.079
6	Traffic Signals - SD742	701	78,099	125	5,608	0.111
7	Traffic Signals - WY942	9	1,807	3	3,000	0.201
8	Rental - SD798		240	1		
9	Rental - SD799		16,274	7		
10	Private Area Lighting - SDA24	5	746	4	1,250	0.149
11	Private Area Lighting - SDB24	1	269	1	1,000	0.269
12	Private Area Lighting - SDC24	8	671	2	4,000	0.084
13	Public Street and Highway Lighting Sales Billed	10,179	1,221,183	220	46,268	0.120
41	TOTAL Billed Commercial and Industrial Sales					
42	TOTAL Unbilled Rev. (See Instr. 6)	10,179	1,221,183			0.120
43	TOTAL					

FERC FORM NO. 1 (ED. 12-95)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	Municipal Pumping - SD720	772	111,608	43	17,953	0.145
2	Municipal Pumping - SD723	8	1,206	2	4,000	0.151
3	Municipal Pumping - SD743	21,369	1,826,156	93	229,774	0.085
4	Municipal Pumping - SD726	32	4,722	1	32,000	0.148
5	Municipal Pumping - WY943	616	65,916	9	68,444	0.107
6	Fuel Clause Accrual		419,364			
7	Renewable Ready		20,983			
8	Other Sales to Public Authorities Billed	22,797	2,449,955	148	154,034	0.107
41	TOTAL Billed Public Street and Highway Lighting	271	23,903			0.088
42	TOTAL Unbilled Rev. (See Instr. 6)	23,068	2,473,858			0.107
43	TOTAL	10,179	1,221,183	220		

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	Not Applicable					
2	Sales to Railroads and Railways Billed					
41	TOTAL Billed Other Sales to Public Authorities					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	23,068	2,473,858	148		

FERC FORM NO. 1 (ED. 12-95)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	Not Applicable					
2	Interdepartmental Sales Billed					
41	TOTAL Billed Sales To Railroads and Railways					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL					

FERC FORM NO. 1 (ED. 12-95)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	TOTAL Billed	1,825,407	235,491,990	74,150	24,618	0.129
2	Total Unbilled Rev.(See Instr. 6)	4,046	290,017			0.072
41	TOTAL Billed Provision For Rate Refunds	1,829,453	235,782,007	74,150	24,672	0.129
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		503			

FERC FORM NO. 1 (ED. 12-95)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						

26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed - All Accounts					
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts					
43	TOTAL - All Accounts					

FERC FORM NO. 1 (ED. 12-95)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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 dur 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).
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 intere 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 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 ou 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.

   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 ar 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 (g) 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 bi demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demar 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, 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 tl 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,line 24.
10. Footnote entries as required and provide explanations following all required data.

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)	Megawatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ((h+i+ (k)
1	City of Gillette Wy	RQ	34	23	23	23	27,102		1,378,534		1,378,
2	Montana Dakota Utilities	RQ	3	47	47	47	95,919	2,314,379	5,507,298	(b)1,578,062	9,399,

3	Municipal Energy Agency of Nebraska	LU	3				119,065		5,954,637		5,954,
4	PacifiCorp	OS	3				1,503		224,034		224,
5	The Energy Authority (MEAN)	OS	3				2,845		128,071		128,
6	WAPA Loveland	OS	3				38,723		2,772,698		2,772,
7	WAPA Colorado River Storage	OS	3				3,695		240,115		240,
8	Avista	OS	3				40		3,000		3,
9	Basin Electric Power	OS	3				970		129,586		129,
10	Burbank, City of	OS	3				400		500,000		500,
11	(a) Cheyenne Light Fuel	OS	3				205,747		10,055,783		10,055,
12	Citigroup	OS	3				262,760		11,659,501		11,659,
13	Colorado Springs Utilities	OS	3				1,111		95,929		95,
14	Coral Power	OS	3				300		12,000		12,
15	Eagle Energy	OS	3				553		38,690		38,
16	Energy Keepers	OS	3				400		30,000		30,
17	Guzmon Electric	OS	3				5,980		227,572		227,
18	Guzmon Renewables	OS	3				1,229		60,242		60,
19	Iberdrola Renewables	OS	3				50		1,250		1,
20	Macquarie Energy	OS	3				528,500		21,844,763		21,844,
21	Morgan Stanley Capital Group	OS	3				2,020		109,110		109,
22	Nevada Power	OS	3				1,550		157,500		157,
23	Northwestern Energy	OS	3				180		7,645		7,
24	Platte River	OS	3				17		6,305		6,
25	Portland General Electric	OS	3				230		40,250		40,
26	Public Srvc Co of CO	OS	3				40		36		

27	Public Srvc Co of New Mex	OS	3				1,397		179,705		179,
28	Rainbow Energy Marketing	OS	3				476		18,160		18,
29	Seattle City Light	OS	3				1,600		52,400		52,
30	Southwest Power Pool	OS	3				834		48,054		48,
31	The Energy Authority	OS	3				1,681		127,420		127,
32	Tenaska	OS	3				2,320		111,600		111,
33	TransAlta Energy	OS	3				800		52,000		52,
34	Tri State Generation	OS	3				1,145		36,310		36,
35	Tucson Electric	OS	3				4,381		261,925		261,
36	Uniper Global Commodities	OS	3				1,993		159,611		159,
37	Unisource	OS	3				1,085		40,350		40,
38	Utah Assoc Muni Power	OS	3				9,631		390,145		390,
39	Utah Muni Power	OS	3				(1,266)		(83,744)		(83,7
40	WACM-NWPP	OS	3				1,124		55,070		55,
41	WACMM1	OS	3				240		45,886		45,
15	Subtotal - RQ						123,021	2,314,379	6,885,832	1,578,062	10,778,
16	Subtotal-Non-RQ						1,205,349		55,793,609		55,793,
17	Total						1,328,370	2,314,379	62,679,441	1,578,062	66,571,

FERC FORM NO. 1 (ED. 12-90)

Page 310-311

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale
Affiliate of Black Hills Power.
(b) Concept: OtherChargesRevenueSalesForResale
Other Charges - Expense Reimbursements

FERC FORM NO. 1 (ED. 12-90)

Page 310-311

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,144,989	1,124,715
5	(501) Fuel	19,207,267	19,711,385
6	(502) Steam Expenses	1,732,353	1,589,496
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	572,409	589,210
10	(506) Miscellaneous Steam Power Expenses	1,468,520	1,406,798
11	(507) Rents	2,931,307	2,660,405
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	27,056,845	27,082,009
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	777,305	813,890
16	(511) Maintenance of Structures	523,695	558,126
17	(512) Maintenance of Boiler Plant	5,690,794	4,980,274
18	(513) Maintenance of Electric Plant	1,010,501	974,944
19	(514) Maintenance of Miscellaneous Steam Plant	48,713	54,929
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	8,051,008	7,382,163
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	35,107,853	34,464,172
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-Nuclear. Power (Enter Total of 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 (Total of Lines 50 & 58)		
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	932,620	951,066
63	(547) Fuel	30,982,775	6,589,513
64	(548) Generation Expenses	735,119	90,369
64.1	(548.1) Operation of Energy Storage Equipment		

65	(549) Miscellaneous Other Power Generation Expenses	599,873	444,345
66	(550) Rents	444,887	295,426
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	33,695,274	8,370,719
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	11,043	2,899
70	(552) Maintenance of Structures	9,179	6,941
71	(553) Maintenance of Generating and Electric Plant	1,894,595	2,159,703
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	80,703	57,174
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	1,995,520	2,226,717
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	35,690,794	10,597,436
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	56,874,760	36,404,022
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	1,024,424	1,148,415
78	(557) Other Expenses		255
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	57,899,184	37,552,692
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	128,697,831	82,614,300
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	995,709	1,029,086
85	(561.1) Load Dispatch-Reliability	145,036	162,681
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	712,958	663,072
87	(561.3) Load Dispatch-Transmission Service and Scheduling	207,247	236,767
88	(561.4) Scheduling, System Control and Dispatch Services	293,386	287,696
89	(561.5) Reliability, Planning and Standards Development	634,604	742,738
90	(561.6) Transmission Service Studies	5,366	78,512
91	(561.7) Generation Interconnection Studies	18,942	(76,296)
92	(561.8) Reliability, Planning and Standards Development Services	123,973	84,140
93	(562) Station Expenses	325,102	403,419
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	117,142	65,866
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	25,962,457	22,919,417

97	(566) Miscellaneous Transmission Expenses	528,765	513,363
98	(567) Rents	42,205	40,786
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	30,112,892	27,151,247
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	195	3,217
102	(569) Maintenance of Structures	32,271	30,037
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	171,885	159,723
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	388,469	588,760
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	2,590	79
111	TOTAL Maintenance (Total of Lines 101 thru 110)	595,410	781,816
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	30,708,302	27,933,063
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 Operation Expenses (Enter Total of Lines 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,147,530	1,426,449
135	(581) Load Dispatching	493,264	482,034
136	(582) Station Expenses	630,125	606,486
137	(583) Overhead Line Expenses	207,693	348,552
138	(584) Underground Line Expenses	402,093	428,639
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	86,066	66,886
140	(586) Meter Expenses	555,862	504,834
141	(587) Customer Installations Expenses	402,568	360,702
142	(588) Miscellaneous Expenses	1,498,296	1,537,345
143	(589) Rents	7,762	(27,431)
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	5,431,259	5,734,496
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	18,310	34,097
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	299,506	157,059
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	8,466,477	8,429,688
150	(594) Maintenance of Underground Lines	260,017	501,268
151	(595) Maintenance of Line Transformers	57,517	47,605
152	(596) Maintenance of Street Lighting and Signal Systems	37,648	85,290
153	(597) Maintenance of Meters	144,106	176,417
154	(598) Maintenance of Miscellaneous Distribution Plant	45,667	60,872
155	TOTAL Maintenance (Total of Lines 146 thru 154)	9,329,248	9,492,296
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	14,760,507	15,226,792
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	65,364	61,736
160	(902) Meter Reading Expenses	133,404	132,261
161	(903) Customer Records and Collection Expenses	1,216,732	1,289,253
162	(904) Uncollectible Accounts	329,952	691,929
163	(905) Miscellaneous Customer Accounts Expenses	274,155	293,582
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	2,019,607	2,468,761

165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	32,374	29,638
168	(908) Customer Assistance Expenses	579,920	403,310
169	(909) Informational and Instructional Expenses	4,387	22,016
170	(910) Miscellaneous Customer Service and Informational Expenses	3,227	19,067
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	619,908	474,031
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	22,919	48,491
176	(913) Advertising Expenses	4,049	28,054
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	26,968	76,545
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	13,564,371	13,838,061
182	(921) Office Supplies and Expenses	3,559,973	4,106,609
183	(Less) (922) Administrative Expenses Transferred-Credit	2,921,089	2,850,848
184	(923) Outside Services Employed	3,797,213	4,566,265
185	(924) Property Insurance	756,467	780,369
186	(925) Injuries and Damages	1,689,910	1,510,707
187	(926) Employee Pensions and Benefits	6,883,828	6,759,753
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	902,300	988,759
190	(929) (Less) Duplicate Charges-Cr.	246,929	228,286
191	(930.1) General Advertising Expenses	566,916	491,055
192	(930.2) Miscellaneous General Expenses	1,257,538	1,063,972
193	(931) Rents	1,772,709	1,756,493
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	31,583,207	32,782,909
195	Maintenance		
196	(935) Maintenance of General Plant	2,245,733	2,204,077
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	33,828,940	34,986,986
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	210,662,063	163,780,478

FERC FORM NO. 1 (ED. 12-93)

Page 320-323

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

PURCHASED POWER (Account 555)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits fo 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. Explai 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 pro 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 consume

   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 adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category sh 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 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 f 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

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

   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 service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

   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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the co 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 avera monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types c Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand durin 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 me
6. Report in column (g) the megawatthours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the respondent for energy storage purchases. Report in columns (i) and (j) the megawatthours of power exchanges received and delivered, used as the b
7. Report demand charges in column (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, components of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For p settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) in generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Pur column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on
9. Footnote entries as required and provide explanations following all required data.

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)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES MegaWatt Hours Received (i)	POWER EXCHANGES MegaWatt Hours Delivered (j)	Dema Char ($) (k)
1	PacifiCorp Colstrip	LF	236	50	50	46	328,935				1,043
2	PacifiCorp	OS	181				45,957				
3	Arizona Electric Power Coop	OS					585				
4	Arizona Public Power	OS									
5		OS					80				

	Avangrid Renwables										
6	Avista Water Power	OS					1,730				
7	Basin Electric	OS					79,611				
8	[a] Cheyenne Light Fuel & Power	OS					55,219				
9	[b] [c] Cheyenne Light Fuel & Power	OS					84,239				
10	Citigroup	OS					10,465				
11	Colorado Springs Utilities	OS					2,890				
12	Corriedale Wind	OS					135,391				
13	Coral Power	OS					2,173				
14	City of Gillette	OS					248				
15	Dynasty Power	OS					1,360				
16	Eagle Energy	OS					3,247				
17	Energy Keepers	OS					8,650				
18	El Paso Energy	OS					690				
19	Guzman Energy	OS					8,875				
20	Guzman Renewables	OS					42				
21	Idaho Power	OS					220				
22	Macquarie Energy LLC	OS					513,054				
23	Morgan Stanley Capital Group	OS					3,252				
24	Northwestern Energy	OS					3,297				
25	Platte River Power Authority	OS					16,081				
26	Platte River Power Authority-SS Wind	OS					29,784				
27	Portland General Elec Company	OS					4,050				
28	Power Ex	OS					200				
29	Public Service of New Mexico	OS					6,747				

30	Puget Sound Energy	OS					1,620				
31	Rainbow Energy Marketing	OS					3,220				
32	Salt River Project	OS					1,260				
33	Seattle City Light	OS					29				
34	Southwest Power Pool	OS					55,450				
35	Spearfish, (City of)	OS					20,089				
36	The Energy Authority West	OS					167				
37	The Energy Authority (MEAN)	OS					10,167				
38	Tenaska Power	OS					400				
39	TransAlta Energy	OS					815				
40	Tri State Generation and Transmission	OS					10,992				
41	Tucson Electric	OS					5,655				
42	UNS Electric	OS					800				
43	Utah Municipal Power Agency	OS					160				
44	WAPA Colorado River Storage Project	OS					165				
45	WAPA - Loveland Area Project	OS					1,861				
46	WAPA - Upper Great Plains Region	OS					2,714				
47	WAPA - WACM Loveland WACMM1	OS					1,394				
48	Xcel Energy - Public Service Co. of Colorado	OS					59,426				
49	Western Area Power Administration	EX							259,245	231,602	
50	Duke Energy	EX									

51	(g) Renewable Energy Rate 44	OS									
52	WACM-NWPP	OS					637				
53	St. George, City of	OS					2,045				
54	Rocky Mountain Generation Cooperative	OS					52				
15	TOTAL						1,526,190		259,245	231,602	1,043

FERC FORM NO. 1 (ED. 12-90)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Affiliate of Black Hills Power.
(b) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Purchase of 30 MW of wind energy from Happy Jack Wind Farm and 30 MW of wind energy from Silver Sage Wind Farm
(c) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Affiliate of Black Hills Power.
(d) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Renewable Energy Customer Purchase Program
(e) Concept: OtherChargesOfPurchasedPower
Colstrip Contract - Termination date 12/31/2023
(f) Concept: OtherChargesOfPurchasedPower
Spinning Reserve
(g) Concept: OtherChargesOfPurchasedPower
Spinning Reserve
(h) Concept: OtherChargesOfPurchasedPower
Deviation Power Exchange
(i) Concept: OtherChargesOfPurchasedPower
Deviation Power Exchange

FERC FORM NO. 1 (ED. 12-90)

Page 326-327

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-tr 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 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 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 Netw Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term F transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-u explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under whic
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the subs received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was c
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in colum on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.
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 t provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges c 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 was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of er
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on l
11. Footnote entries and provide explanations following all required data.

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 Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER O ENERGY Megawatt Hours Received (i)	Mega Ho Deliv (
1	[(a)] South Dakota, State of	Western Area Power Admin	BHSU-Spearfish, SDSMT	OS		Rapid City SD	South Dakota West		4,115	
2	[(b)] Basin Electric Power	Basin Electric Power	Black Hills Power	OS		RC DC Tie	RC DC		1,215,615	1,21
3	Black Hills Power	Black Hills Power	Black Hills Power	FNS	11	Various	Various		2,000,725	2,00
4	Basin Electric Power	Basin Electric Power	Basin Electric Power	FNO	11	Various	Various		2,027,266	2,02
5	[(c)] Cheyenne Light, Fuel and Power	[(p)] Cheyenne Light, Fuel and Power	[(y)] Cheyenne Light, Fuel and Power	FNO	11	Various	Various		970,476	97
6	City of Gillette	Black Hills Power	City of Gillette	FNO	11	Various	Various		337,801	33
7	South Dakota, State of	Western Area Power Administration	South Dakota State of	FNO	11	Various	Various		16,740	1
8	[(d)] Cheyenne Light, Fuel and Power	[(q)] Black Hills Wyoming	[(z)] Cheyenne Light, Fuel and Power , Basin Electric Power	LFP	7	WYODAK	SGW	60	22,361	2

9	MEAN	Black Hills Power	MEAN, Western Area Power Administration-LAP	LFP	7	WYODAK, WY69	SGW	35	219,111	21
10	WMPA	Wyoming Municipal Power Agency	Wyoming municipal Power Agency, Tri-State Generation and Transmission	LFP	7	DRYFORK	DJ	30	66,732	6
11	Basin Electric Power	Basin Electric Power	Basin Electric Power	LFP	7	DRYFORK	RC	130	14,682	1
12	Basin Electric Power	Basin Electric Power	Wyoming Municipal Power Agency	LFP	7	DRYFORK	DJ	30	108,750	10
13	Basin Electric Power	Basin Electric Power	Basin Electric Power	SFP	7	DRYFORK	DJ		2,024	
14	Basin Electric Power	Basin Electric Power	Basin Electric Power	SFP	7	DJ	WYODAK		4,645	
15	Basin Electric Power	Basin Electric Power	Basin Electric Power	SFP	7	SGW	WYODAK		7	
16	Basin Electric Power	Basin Electric Power	Basin Electric Power	SFP	7	DRYFORK	SGW		36	
17	Black Hills Power	Black Hills Power	Black Hills Power	SFP	7	DRYFORK	SGW		550	
18	(e) Black Hills Wyoming	(r) Black Hills Wyoming	(aa) Black Hills Wyoming	SFP	7	WYODAK	DJ		1,890	
19	(f) Black Hills Wyoming	(s) Black Hills Wyoming	(ab) Black Hills Wyoming	SFP	7	DJ	WYODAK		10	
20	Macquarie Energy LLC (MCPI01)	Macquarie Energy LLC	Macquarie Energy LLC	SFP	7	RC	DJ		215	
21	MAG Energy Solutions	MAG Energy Solutions	MAG Energy Solutions	SFP	7	DJ	SGW		4,464	
22	PacifiCorp	PacifiCorp	PacifiCorp	SFP	7	WYODAK	ANTELOPE		10,540	1
23	Rainbow Energy Marketing Corporation	Rainbow Energy Marketing Corporation	Rainbow Energy Marketing Corporation	SFP	7	RC	DJ		56	
24	Shell Energy North America	Shell Energy North America	Shell Energy North America	SFP	7	RC	DJ		794	
25	Powerex Corp	Powerex Corp	Powerex Corp	SFP	7	RC	DJ		121	
26	The Energy Authority (TEA)	The Energy Authority	The Energy Authority	SFP	7	RC	DJ		855	
27	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	DJ	WYODAK		21,713	2

28	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	DJ	DRYFORK		1,536
29	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	DJ	WSTAR		97
30	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	DJ	RC		944
31	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	DJ	SHERIDAN		1,362
32	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	DJ	SGW		50
33	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	DRYFORK	WYODAK		282
34	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	RC	DRYFORK		68
35	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	RC	SGW		267
36	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	DRYFORK	DJ		78,216
37	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	SGW	RC		818
38	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	DRYFORK	RC		1,906
39	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	DRYFORK	SGW		27,123
40	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	DRYFORK	SHERIDAN		178
41	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	RC69	RC		70
42	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	SGW	DJ		128
43	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	SGW	DRYFORK		1,737
44	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	SGW	SHERIDAN		410
45	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	SGW	WYODAK		5,247
46	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	WSTAR	WYODAK		97
47		Basin Electric Power	Basin Electric Power	NF	8	WYODAK	DJ		32

	Basin Electric Power									
48	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	WYODAK	RC		93	
49	(g) Black Hills Colorado Electric	Basin Electric Power	(ac) Black Hills Colorado Electric	NF	8	RC	SGW		60	
50	(h) Black Hills Colorado Electric	Basin Electric Power	(ad) Black Hills Colorado Electric	NF	8	DRYFORK	SGW		50	
51	(i) Black Hills Colorado Electric	Basin Electric Power	(ae) Black Hills Colorado Electric	NF	8	DRYFORK	DJ		75	
52	(j) Black Hills Wyoming	(t) Black Hills Wyoming	(af) Black Hills Wyoming	NF	8	DJ	WYODAK		341	
53	(k) Black Hills Wyoming	(u) Black Hills Wyoming	Black Hills Power	NF	8	WYODAK	SGW		6,999	(
54	(l) Black Hills Wyoming	(v) Black Hills Wyoming	Tristate	NF	8	WYODAK	DJ		23,452	2:
55	(m) Black Hills Wyoming	PacifiCorp	Black Hills Power	NF	8	WYODAK	WYODAK		6	
56	Black Hills Power	Pacificorp, Public Service Company of New Mexico, Public Service Company of Colorado, Black Hills Power	Black Hills Power	NF	8	DJ	RC		40,323	4(
57	Black Hills Power	BC Hyrdro,	(ag) Cheyenne Light, Fuel and Power	NF	8	DJ	SGW		17	
58	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	DJ	WYODAK		75	
59	Black Hills Power	Pacificorp, Public Service Company of New Mexico, Public Service Company of Colorado, Black Hills Power	Black Hills Power	NF	8	WYODAK	SHERIDAN		10,059	1(
60	Black Hills Power	Basin Electric Power	Black Hills Power	NF	8	DRYFORK	DJ		17	
61	Black Hills Power	Basin Electric Power	Black Hills Power	NF	8	DRYFORK	RC		3,637	:
62	Black Hills Power	Basin Electric Power	Black Hills Power	NF	8	DRYFORK	SGW		285	
63	Black Hills Power	Black Hills Power	Avangrid Renewables, LC	NF	8	RC	DJ		70	
64				NF	8	RC	SGW		7	

	Black Hills Power	Black Hills Power	Holy Cross, Stegall, Tuscon Electric Power Company, Western Area Power Admin							
65	Black Hills Power	Black Hills Power	Western Area Power Authority, Tristate	NF	8	SGW	RC		12,815	1
66	Black Hills Power	Black Hills Power	Basin Electric Power	NF	8	WYODAK	DJ		67,439	6
67	Black Hills Power	Black Hills Power	Basin Electric Power	NF	8	WYODAK	RC		40,842	4
68	Black Hills Power	Basin Electric Power	Black Hills Power	NF	8	WYODAK	SGW		21,215	2
69	Black Hills Power	Black Hills Power	Western Area Power Administration, Holy Cross	NF	8	WYODAK	WYODAK		2,788	
70	Brookfield Renewable Trading and Marketing LP	Brookfield Renewable Trading and Marketing LP	Brookfield Renewable Trading and Marketing LP	NF	8	RC	DJ		1	
71	(n) Cheyenne Light, Fuel and Power	Black Hills Power	Black Hills Power	NF	8	WYODAK	SGW		191	
72	(o) Cheyenne Light, Fuel and Power	Black Hills Power	Black Hills Power	NF	8	WYODAK	DJ		1,688	
73	Shell Energy North America (CORP)	Shell Energy North America	Shell Energy North America	NF	8	DJ	RC		600	
74	Shell Energy North America (CORP)	Shell Energy North America	Shell Energy North America	NF	8	RC	SHERIDAN		750	
75	Shell Energy North America (CORP)	Shell Energy North America	Shell Energy North America	NF	8	RC	DJ		52,597	5
76	Shell Energy North America (CORP)	Shell Energy North America	Shell Energy North America	NF	8	SGW	DJ		51	
77	CP Energy Marketing (US) Inc (EEMU)	CP Energy Marketing (US) Inc	CP Energy Marketing (US) Inc	NF	8	RC	DJ		240	
78	Dynasty Power Inc.	Dynasty Power Inc.	Dynasty Power Inc.	NF	8	DJ	RC		427	
79	Dynasty Power Inc.	Dynasty Power Inc.	Dynasty Power Inc.	NF	8	DJ	SGW		649	
80	Dynasty Power Inc.	Dynasty Power Inc.	Dynasty Power Inc.	NF	8	RC	DJ		2	
81	Dynasty Power Inc.	Dynasty Power Inc.	Dynasty Power Inc.	NF	8	RC	SGW		18,105	1

82	Dynasty Power Inc.	Dynasty Power Inc.	Dynasty Power Inc.	NF	8	SGW	DJ		9,780	9
83	Dynasty Power Inc.	Dynasty Power Inc.	Dynasty Power Inc.	NF	8	SGW	RC		656	
84	Dynasty Power Inc.	Dynasty Power Inc.	Dynasty Power Inc.	NF	8	RC	SGW		176	
85	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	NF	8	DJ	RC		145	
86	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	NF	8	DJ	SGW		335	
87	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	NF	8	RC	SGW		9,807	9
88	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	NF	8	RC	DJ		18,291	18
89	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	NF	8	SGW	DJ		365	
90	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	NF	8	SGW	RC		10	
91	Macquarie Energy LLC (MCPI01)	Macquarie Energy LLC	Macquarie Energy LLC	NF	8	RC	DJ		9,009	9
92	MAG Energy Solutions	MAG Energy Solutions	MAG Energy Solutions	NF	8	DJ	WYODAK		54	
93	MAG Energy Solutions	MAG Energy Solutions	MAG Energy Solutions	NF	8	RC	DJ		27,773	27
94	MAG Energy Solutions	MAG Energy Solutions	MAG Energy Solutions	NF	8	RC	WYODAK		64	
95	Municipal Energy Agency of Nebraska	Black Hills Power	MEAN	NF	8	WYODAK	SGW		5	
96	Morgan Stanley Capital Group	Morgan Stanley Capital Group	Morgan Stanley Capital Group	NF	8	DJ	RC			
97	Mercuria Energy America, LLC (MEAI01)	Mercuria Energy America, LLC	Mercuria Energy America, LLC	NF	8	DJ	SGW		6,651	6
98	Mercuria Energy America, LLC	Mercuria Energy America, LLC	Mercuria Energy America, LLC	NF	8	RC	DJ		44,278	44
99	Mercuria Energy America, LLC	Mercuria Energy America, LLC	Mercuria Energy America, LLC	NF	8	SGW	DJ		1	
100	Pacificorp	Pacificorp	Black Hills Power, Pacificorp	NF	8	WYODAK	ANTELOPE		65	
101	Powerex Corp	Powerex Corp	Powerex Corp	NF	8	DJ	SGW		300	

102	Powerex Corp	Powerex Corp	Powerex Corp	NF	8	RC	WYODAK		1,595
103	Powerex Corp	Powerex Corp	Powerex Corp	NF	8	RC	DJ		5,776
104	Powerex Corp	Powerex Corp	Powerex Corp	NF	8	DJ	RC		565
105	Powerex Corp	Powerex Corp	Powerex Corp	NF	8	RC	SGW		40
106	Powerex Corp	Powerex Corp	Powerex Corp	NF	8	SGW	WYODAK		35
107	Public Service Company of Colorado	Public Service Company of Colorado	Public Service Company of Colorado	NF	8	DJ	RC		60
108	Public Service Company of Colorado	Public Service Company of Colorado	Public Service Company of Colorado	NF	8	SGW	RC		1,505
109	Rainbow Energy Marketing Corporation	Rainbow Energy Marketing Corporation, Basin Electric Power	Rainbow Energy Marketing Corporation, Basin Electric Power	NF	8	SGW	RC		36
110	Rainbow Energy Marketing Corporation	Rainbow Energy Marketing Corporation, Basin Electric Power	Rainbow Energy Marketing Corporation, Basin Electric Power	NF	8	DJ	RC		464
111	Rainbow Energy Marketing Corporation	Rainbow Energy Marketing Corporation, Basin Electric Power	Rainbow Energy Marketing Corporation, Basin Electric Power	NF	8	DJ	SGW		25
112	Rainbow Energy Marketing Corporation	Rainbow Energy Marketing Corporation, Basin Electric Power	Rainbow Energy Marketing Corporation, Basin Electric Power	NF	8	DRYFORK	RC		170
113	Rainbow Energy Marketing Corporation	Rainbow Energy Marketing Corporation, Basin Electric Power	Rainbow Energy Marketing Corporation, Basin Electric Power	NF	8	RC	SGW		618
114	Rainbow Energy Marketing Corporation	Rainbow Energy Marketing Corporation, Basin Electric Power	Rainbow Energy Marketing Corporation, Basin Electric Power	NF	8	RC	DJ		12,724
115	TEC Energy Inc	TEC Energy Inc	TEC Energy Inc	NF	8	RC	DJ		2,067
116	The Energy Authority (TEA)	The Energy Authority (TEA)	The Energy Authority (TEA)	NF	8	RC	DJ		3,513
117	The Energy Authority (TEA)	The Energy Authority (TEA)	The Energy Authority (TEA)	NF	8	DJ	RC		30

118	The Energy Authority (TEA)	The Energy Authority (TEA)	The Energy Authority (TEA)	NF	8	RC	SGW		149	
119	The Energy Authority (TEA)	The Energy Authority (TEA)	The Energy Authority (TEA)	NF	8	SGW	DJ		223	
120	The Energy Authority (TEA)	The Energy Authority (TEA)	The Energy Authority (TEA)	NF	8	WYODAK	SGW		44	
121	TransAlta Energy Marketing U.S.Inc. (TEMU)	TransAlta Energy Marketing U.S.Inc.	TransAlta Energy Marketing U.S.Inc.	NF	8	RC	SGW		239	
122	TransAlta Energy Marketing U.S.Inc. (TEMU)	TransAlta Energy Marketing U.S.Inc.	TransAlta Energy Marketing U.S.Inc.	NF	8	DJ	RC		300	
123	TransAlta Energy Marketing U.S.Inc. (TEMU)	TransAlta Energy Marketing U.S.Inc.	TransAlta Energy Marketing U.S.Inc.	NF	8	RC	DJ		11,702	1
124	Tenaska Power Services Co	Tenaska Power Services Co	Tenaska	NF	8	RC	DJ		200	
125	Westar Energy Generation & Marketing (WRGS)	Westar Energy Generation & Marketing	Westar Energy Generation & Marketing	NF	8	DJ	RC			
126	WestConnect	(w) Black Hills Colorado Electric	(ah) Black Hills Colorado Electric	NF	8	RC	SGW		80	
127	WestConnect	(x) Black Hills Colorado Electric	(ai) Black Hills Colorado Electric	NF	8	DJ	SGW		227	
128	WestConnect	Black Hills Power	Black Hills Power	NF	8	WYODAK	DJ		160	
129	WestConnect	CP Energy Marketing (US) Inc.	CP Energy Marketing (US) Inc	NF	8	RC	SGW		1	
130	WestConnect	CP Energy Marketing (US) Inc.	CP Energy Marketing (US) Inc	NF	8	RC	DJ		65	
131	WestConnect	Dynasty Power Inc.	Dynasty Power Inc.	NF	8	RC	SGW		7,139	
132	WestConnect	Dynasty Power Inc.	Dynasty Power Inc.	NF	8	RC	DJ		4,872	4
133	WestConnect	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	NF	8	SGW	DJ		30	
134	WestConnect	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	NF	8	DJ	SGW		50	
135	WestConnect	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	NF	8	RC	DJ		75	

136	WestConnect	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	NF	8	RC	SGW		596	
137	WestConnect	Macquarie Energy LLC	Macquarie Energy LLC	NF	8	RC	DJ		75	
138	WestConnect	MAG Energy Solutions	MAG Energy Solutions	NF	8	DJ	SGW		160	
139	WestConnect	MAG Energy Solutions	MAG Energy Solutions	NF	8	RC	SGW		11	
140	WestConnect	Rainbow Energy Marketing Corporation	Rainbow Energy Marketing Corporation	NF	8	RC	SGW		317	
141	WestConnect	Rainbow Energy Marketing Corporation	Rainbow Energy Marketing Corporation	NF	8	RC	DJ		50	
142	WestConnect	Shell Energy North America	Shell Energy North America	NF	8	RC	DJ		124	
143	WestConnect	Shell Energy North America	Shell Energy North America	NF	8	RC	SGW		500	
144	WestConnect	TEC Energy Inc.	TEC Energy Inc.	NF	8	WYODAK	SGW		1	
145	WestConnect	TEC Energy Inc.	TEC Energy Inc.	NF	8	RC	DJ		225	
146	WestConnect	Tenaska Power Services Co	Tenaska Power Services Co	NF	8	SGW	RC		50	
147	WestConnect	The Energy Authority (TEA)	The Energy Authority (TEA)	NF	8	RC	DJ		3,652	3
148	WestConnect	The Energy Authority (TEA)	The Energy Authority (TEA)	NF	8	DJ	RC		36	
149	WestConnect	The Energy Authority (TEA)	The Energy Authority (TEA)	NF	8	DJ	SGW		20	
150	WestConnect	The Energy Authority (TEA)	The Energy Authority (TEA)	NF	8	RC	SGW		7,700	7
151	WestConnect	The Energy Authority (TEA)	The Energy Authority (TEA)	NF	8	SGW	DJ		48	
152	WestConnect	The Energy Authority (TEA)	The Energy Authority (TEA)	NF	8	SGW	RC		250	
153	WestConnect	TransAlta Energy Marketing U.S.Inc.	TransAlta Energy Marketing U.S.Inc.	NF	8	RC	DJ		185	
154	WestConnect	TransAlta Energy Marketing U.S.Inc.	TransAlta Energy Marketing U.S.Inc.	NF	89	RC	SGW		675	
35	TOTAL								7,676,047	7,67

FERC FORM NO. 1 (ED. 12-90)

Page 328-330

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: PaymentByCompanyOrPublicAuthority
Reclass of Distribution not Transmission - stat adjustment in Q4
(b) Concept: PaymentByCompanyOrPublicAuthority
Losses received on RC DC Tie
(c) Concept: PaymentByCompanyOrPublicAuthority
Affiliate of Black Hills Power
(d) Concept: PaymentByCompanyOrPublicAuthority
Affiliate of Black Hills Power
(e) Concept: PaymentByCompanyOrPublicAuthority
Affiliate of Black Hills Power
(f) Concept: PaymentByCompanyOrPublicAuthority
Affiliate of Black Hills Power
(g) Concept: PaymentByCompanyOrPublicAuthority
Affiliate of Black Hills Power
(h) Concept: PaymentByCompanyOrPublicAuthority
Affiliate of Black Hills Power
(i) Concept: PaymentByCompanyOrPublicAuthority
Affiliate of Black Hills Power
(j) Concept: PaymentByCompanyOrPublicAuthority
Affiliate of Black Hills Power
(k) Concept: PaymentByCompanyOrPublicAuthority
Affiliate of Black Hills Power
(l) Concept: PaymentByCompanyOrPublicAuthority
Affiliate of Black Hills Power
(m) Concept: PaymentByCompanyOrPublicAuthority
Affiliate of Black Hills Power
(n) Concept: PaymentByCompanyOrPublicAuthority
Affiliate of Black Hills Power
(o) Concept: PaymentByCompanyOrPublicAuthority
Affiliate of Black Hills Power
(p) Concept: TransmissionEnergyReceivedFromCompanyOrPublicAuthorityName
Affiliate of Black Hills Power
(q) Concept: TransmissionEnergyReceivedFromCompanyOrPublicAuthorityName
Affiliate of Black Hills Power
(r) Concept: TransmissionEnergyReceivedFromCompanyOrPublicAuthorityName
Affiliate of Black Hills Power
(s) Concept: TransmissionEnergyReceivedFromCompanyOrPublicAuthorityName
Affiliate of Black Hills Power
(t) Concept: TransmissionEnergyReceivedFromCompanyOrPublicAuthorityName
Affiliate of Black Hills Power
(u) Concept: TransmissionEnergyReceivedFromCompanyOrPublicAuthorityName
Affiliate of Black Hills Power
(v) Concept: TransmissionEnergyReceivedFromCompanyOrPublicAuthorityName
Affiliate of Black Hills Power
(w) Concept: TransmissionEnergyReceivedFromCompanyOrPublicAuthorityName

Affiliate of Black Hills Power

(x) Concept: TransmissionEnergyReceivedFromCompanyOrPublicAuthorityName

Affiliate of Black Hills Power

(y) Concept: TransmissionEnergyDeliveredToCompanyOrPublicAuthorityName

Affiliate of Black Hills Power

(z) Concept: TransmissionEnergyDeliveredToCompanyOrPublicAuthorityName

Affiliate of Black Hills Power

(aa) Concept: TransmissionEnergyDeliveredToCompanyOrPublicAuthorityName

Affiliate of Black Hills Power

(ab) Concept: TransmissionEnergyDeliveredToCompanyOrPublicAuthorityName

Affiliate of Black Hills Power

(ac) Concept: TransmissionEnergyDeliveredToCompanyOrPublicAuthorityName

Affiliate of Black Hills Power

(ad) Concept: TransmissionEnergyDeliveredToCompanyOrPublicAuthorityName

Affiliate of Black Hills Power

(ae) Concept: TransmissionEnergyDeliveredToCompanyOrPublicAuthorityName

Affiliate of Black Hills Power

(af) Concept: TransmissionEnergyDeliveredToCompanyOrPublicAuthorityName

Affiliate of Black Hills Power

(ag) Concept: TransmissionEnergyDeliveredToCompanyOrPublicAuthorityName

Affiliate of Black Hills Power

(ah) Concept: TransmissionEnergyDeliveredToCompanyOrPublicAuthorityName

Affiliate of Black Hills Power

(ai) Concept: TransmissionEnergyDeliveredToCompanyOrPublicAuthorityName

Affiliate of Black Hills Power

(aj) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ak) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(al) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(am) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(an) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ao) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ap) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(aq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ar) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(as) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(at) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(au) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(av) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(aw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ax) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ay) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(az) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ba) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(bb) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(bc) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(bd) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(be) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(bf) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(bg) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(bh) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(bi) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(bj) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(bk) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(bl) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(bm) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(bn) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(bo) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(bp) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(bq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(br) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(bs) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(bt) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(bu) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(bv) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(bw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(bx) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(by) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(bz) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ca) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(cb) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(cc) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(cd) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ce) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(cf) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(cg) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ch) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ci) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(cj) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ck) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(cl) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(cm) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(cn) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(co) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(cp) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(cq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(cr) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(cs) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ct) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(cu) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(cv) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(cw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(cx) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(cy) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(cz) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(da) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(db) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(dc) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(dd) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(de) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(df) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(dg) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(dh) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(di) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(dj) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(dk) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(dl) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(dm) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(dn) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(do) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(dp) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(dq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(dr) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ds) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(dt) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(du) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(dv) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(dw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(dx) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(dy) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(dz) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ea) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(eb) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ec) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ed) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ee) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ef) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(eg) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(eh) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ei) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ej) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ek) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(el) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(em) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(en) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(eo) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ep) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(eq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(er) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(es) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(et) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(eu) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ev) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ew) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ex) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ey) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ez) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(fa) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(fb) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(fc) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(fd) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(fe) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ff) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(fg) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(fh) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(fi) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(fj) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(fk) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(fl) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(fm) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(fn) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(fo) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(fp) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(fq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(fr) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(fs) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(ft) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(fu) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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

(fv) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Other Charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.
(fw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Other Charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.
(fx) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Other Charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.
(fy) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Other Charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.
(fz) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Other Charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.
(ga) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Other Charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.
(gb) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Other Charges are ancillary revenue charges for reactive voltage support, scheduling, FERC assesments and redispatch. Also includes CUS true-ups.
(gc) Concept: RevenuesFromTransmissionOfElectricityForOthers
Rapid City DC Tie. Black Hills Power is a 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.

FERC FORM NO. 1 (ED. 12-90)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
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					
48					
49					
40	TOTAL				

FERC FORM NO. 1 (REV 03-07)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

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: MegaWatt Hours Received (c)	TRANSFER OF ENERGY: MegaWatt 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	PacifiCorp	FNS	304,297	304,297		1,391,205		1,391,205
2	PacifiCorp	LFP	438,000	438,000	1,783,288			1,783,288
3	Arizona Power	NF	1,840	1,840		10,216		10,216
4	Basin Electric	NF	42,776	42,776		64,021		64,021
5	Colo River Storage	NF	25,523	25,523		61,667		61,667
6	Deseret	NF	1,745	1,745		10,359		10,359
7	Idaho Power Co	NF	803	803		4,428		4,428
8	Northwestern Energy	SFP	2,043	2,043		11,618		11,618
9	Nevada Power	NF	500	500		2,970		2,970
10	Public Service Co of Colo	NF	1,949	1,949		9,939		9,939
11	Southwest Power Pool	NF	78,554	78,554		637,694		637,694
12	Tri-State Generation	NF	375	375		3,845		3,845
13	Western Area Power	OS	60	60		142		142
14	Western Area Power Loveland	NF				2,547,973		2,547,973
15	(a) Cheyenne Light, Fuel	NF				48		48
16	Western Area Power	OS				110,638		110,638
17	(b) (c) Common Use System (CUS)	LFP	27,297	27,297	2,909,360		0	2,909,360

18	(d) (e) BHBE - CUS	NF	125	125	548			548
19	Transmission Accruals	OS				(816,899)		(816,899)
20	(f) WAPA	OS					1,627,510	1,627,510
21	(g) Common Use System (CUS)	FNS	2,000,725	2,000,725		14,016,234	1,192,155	15,208,389
22	(h) Common Use System (CUS)	NF	199,588	199,588	0	199,588	183,910	383,498
	TOTAL		3,126,200	3,126,200	4,693,196	18,265,686	3,003,575	25,962,457

FERC FORM NO. 1 (REV. 02-04)

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Affiliate of Black Hills Power

(b) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Affiliate transactions - BHP is a joint owner of the Common Use Transmission System (CUS); Amounts shown are charges from the CUS. Amounts included in Other Charges represent ancillary charges for Reactive Voltage Support, Scheduling, and FERC Assesments.

(c) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Rapid City DC Tie Transactions

(d) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Affiliate transactions - BHP is a joint owner of the Common Use Transmission System (CUS); Amounts shown are charges from the CUS. Amounts included in Other Charges represent ancillary charges for Reactive Voltage Support, Scheduling, and FERC Assesments.

(e) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Rapid City DC Tie Transactions

(f) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Regulation costs paid to WAPA

(g) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Affiliate transactions - BHP is a joint owner of the Common Use Transmission System (CUS); Amounts shown are charges from the CUS. Amounts included in Other Charges represent ancillary charges for Reactive Voltage Support, Scheduling, and FERC Assesments.

(h) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Affiliate transactions - BHP is a joint owner of the Common Use Transmission System (CUS); Amounts shown are charges from the CUS. Amounts included in Other Charges represent ancillary charges for Reactive Voltage Support, Scheduling, and FERC Assesments.

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	131,779
2	Nuclear Power Research Expenses	0
3	Other Experimental and General Research Expenses	0
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	0
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Other Expense>=$5,000 Show purpose, recipient & amount. Group if <$5,000	352,195
7	Directors' Fees and Expenses	603,952
8	Bank Fees	157,501
9	Travel	12,111
10	Materials & Supplies	
11	Economic Development	
12	Labor & Loadings	
13	Handouts & Brochures	
14	Contractors/Consultants	
46	TOTAL	1,257,538

FERC FORM NO. 1 (ED. 12-94)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

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 B 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 of 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	12,361,351			1,774,436	14,135,787
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	7,151,444	33,115			7,184,559
7	Transmission Plant	5,578,067				5,578,067
8	Distribution Plant	12,987,018				12,987,018
9	Regional Transmission and Market Operation					
10	General Plant	8,318,965				8,318,965
11	Common Plant-Electric					
12	TOTAL	46,396,845	33,115		1,774,436	48,204,396

B. Basis for Amortization Charges

Amortization of other electric plant will occur over 10 years.

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	0.817	60 years	(22)%	12.07%		
14	Wyodak	117.569	58 years	(13)%	2.86%		24 years, 2 months
15	Neil Simpson II	188.957	60 years	(14)%	2.9%		28 years, 5 months
16	Wygen III	141.221	60 years	(13)%	2.64%		40 years, 5 months
17	SUBTOTAL STEAM PROD	448.564					
18	Other Production Plant						
19	Lange CT	33.356	44 years	(5)%	2.29%		29 years, 7 months
20	Neil Simpson I CT	35.391	44 years	(5)%	2.56%		28 years, 3 months
21	Ben French CT	22.638	44 years	(13)%	2.61%		14 years, 2 months
22	Ben French Diesel CT	2.238	45 years	(22)%	5.06%		6 years, 6 months
23	Cheyenne Prairie Generating Station	95.422	40 years	(4)%	2.98%		42 years
24	Corriedale Wind Farm	48.876	25 years		4.28%		25 years
25	SUBTOTAL OTHER PROD	237.921					
26	Transmission Plant						
27	(352)Structures and Im	2.044	50 years	(10)%	1.83%		39 years, 9 months
28	(353)Station Equipment	75.326	42 years	(5)%	2.13%		35 years, 9 months
29	(354)Towers and Fixture	0.883	60 years	(20)%	1.74%		55 years, 7 months
30	(355)Poles and Fixture	91.001	55 years	(30)%	2.74%		37 years, 6 months
31	(356)Overhead Conductor	73.607	60 years	(20)%	2.05%		44 years, 8 months
32	(359)Roads & Trails	0.007	60 years		1.72%		31 years, 6 months
33	SUBTOTAL TRANSMISSION	242.868					
34	Distribution Plant						
35	(361)Structures and Im	2.203	40 years	(5)%	2.45%		33 years, 4 months
36	(362)Station Equipment	110.657	45 years	(10)%	2.27%		34 years, 1 month
37	(364)Poles, Towers &	111.044	50 years	(70)%	3.64%		37 years
38	(365)Overhead Conductor	70.358	50 years	(20)%	2.26%		38 years, 6 months
39	(366)Underground Cond	18.365	37 years	(5)%	2.81%		33 years, 1 month
40	(367)Underground Cond	63.678	40 years	(5)%	2.32%		30 years, 1 month

41	(368)Line Transformers	57.604	36 years		2.41%		27 years, 1 month
42	(369)Services	39.421	62 years	(50)%	2.29%		51 years, 4 months
43	(370)Meters	10.279	21 years		5.23%		18 years, 4 months
44	(371)Installation on C	2.934	30 years	(10)%	3.22%		22 years, 2 months
45	(373)Street Lighting	2.273	25 years	(15)%	3.96%		17 years, 1 month
46	SUBTOTAL DISTRIBUTION	488.816					
47	General Plant						
48	(390)Structures and Im	83.278	40 years	(10)%	1.67%		32 years, 5 months
49	(391)Office Furniture	17.131	9 years, 9 months, 18 days		13.82%		5 years, 11 months
50	(392)Transportation Eq	20.323	13 years	(10)%	3.45%		10 years, 6 months
51	(393)Stores Equipment	0.167	20 years		9.32%		4 years, 6 months
52	(394)Tools, Shop, & Ga	3.478	25 years		3.33%		17 years
53	(395)Laboratory Equip	0.791	25 years		7.46%		13 years, 2 months
54	(396)Power Operated Eq	4.649	30 years	(20)%	1.28%		26 years, 8 months
55	(397)Communication Equ	6.861	20 years		5.63%		13 years, 8 months
56	(398)Miscellaneous Equ	1.315	20 years		5.8%		13 years, 2 months
57	SUBTOTAL GENERAL	137.993					
58	TOTAL	1,556.162					

FERC FORM NO. 1 (REV. 12-03)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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) rela 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 previo
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 columns (f), (g), and (h), expenses incurred during the 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 DUR	
						CURRENTLY CHARGED TO					
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 Expenses for Current Year (d)	Deferred in Account 182.3 at Beginning of Year (e)	Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)
1	FERC Assessment	384,170		384,170		Reg Serv.	928				
2	Regulatory Assets				1,051,661					588/928	420,665
3	PUC Assessments	383,802	106,561	490,363		Reg Serv.	588				
46	TOTAL	767,972	106,561	874,533	1,051,661						420,665

FERC FORM NO. 1 (ED. 12-96)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 and 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 and 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 and 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 and D Performed Externally:
     1. Research Support to the electrical Research Council or the Electric Power Research Institute
     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 and 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 and 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 and 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 and 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.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Account (e)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Amount (f)	Unamortized Accumulation (g)
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							

12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							

FERC FORM NO. 1 (ED. 12-87)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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	4,194,759		
4	Transmission	1,741,947		
5	Regional Market			
6	Distribution	2,760,140		
7	Customer Accounts	766,270		
8	Customer Service and Informational	298,998		
9	Sales	16,969		
10	Administrative and General	13,648,526		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	23,427,609		
12	Maintenance			
13	Production	2,544,721		
14	Transmission	77,746		
15	Regional Market			
16	Distribution	1,179,802		
17	Administrative and General	32,886		
18	TOTAL Maintenance (Total of lines 13 thru 17)	3,835,155		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	6,739,480		
21	Transmission (Enter Total of lines 4 and 14)	1,819,693		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	3,939,942		
24	Customer Accounts (Transcribe from line 7)	766,270		
25	Customer Service and Informational (Transcribe from line 8)	298,998		
26	Sales (Transcribe from line 9)	16,969		
27	Administrative and General (Enter Total of lines 10 and 17)	13,681,412		

28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	27,262,764		27,262,764
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			
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	293,903		293,903
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	27,556,667		27,556,667
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	3,184,225		3,184,225
69	Gas Plant			0
70	Other (provide details in footnote):		3,536,830	3,536,830
71	TOTAL Construction (Total of lines 68 thru 70)	3,184,225	3,536,830	6,721,055
72	Plant Removal (By Utility Departments)			
73	Electric Plant	313,863		313,863
74	Gas Plant			0
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	313,863		313,863
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	Other Regulatory Assets (183.2)	(648)		(648)
80	A/R Third Party Billing (143)	289		289
81	Cleared through Account (163)	697,622		697,622
82	Cleared through Account (184)	2,645,018		2,645,018
83	Cleared through Account (242)	193,175		193,175
84	Cleared through Account (186)	1,015		1,015
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	3,536,471		3,536,471
96	TOTAL SALARIES AND WAGES	34,591,226	3,536,830	38,128,056

FERC FORM NO. 1 (ED. 12-88)

Page 354-355

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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 Electric 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 the order of the Commission or other authorization.

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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)				
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)			5	5
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					

28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL			5	5

FERC FORM NO. 1 (NEW. 12-05)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) 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)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	2,801,968	KW/M	661,175	9,136,636	KW/M	2,131,964
2	Reactive Supply and Voltage	2,801,968	KW/M	936,210	9,136,636	KW/M	1,293,678
3	Regulation and Frequency Response	5,374	MW	118,239			
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other	1529936	MWH	[(a)]116,734	4,448,739	MWH	[(b)]339,439
8	Total (Lines 1 thru 7)	7,139,246		1,832,358	22,722,011		3,765,081

FERC FORM NO. 1 (New 2-04)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedAmount
FERC Annual Charge Assessment.
(b) Concept: AncillaryServicesSoldAmount
FERC Annual Charge Assessment.

FERC FORM NO. 1 (New 2-04)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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.

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)
	NAME OF SYSTEM: Black Hills Power									
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									
	NAME OF SYSTEM: Common Use System (CUS)									
1	January	764	25	18	282	423	252			58
2	February	837	11	18	324	465	252			111
3	March	704	1	19	290	354	252			13

4	Total for Quarter 1				896	1,242	756			182
5	April	772	14	9	247	479	192			30
6	May	746	21	11	226	460	192			8
7	June	913	15	17	359	498	192		10	213
8	Total for Quarter 2				832	1,437	576			251
9	July	971	26	13	356	492	192			28
10	August	910	8	18	339	492	192			13
11	September	855	10	17	322	473	192		5	175
12	Total for Quarter 3				1,017	1,457	576			216
13	October	694	5	17	277	377	192			8
14	November	733	17	18	279	413	192			349
15	December	912	31	18	287	566	192		25	254
16	Total for Quarter 4				843	1,356	576			611
17	Total				3,588	5,492	[(a)]2,484			[(b)]1,260

FERC FORM NO. 1 (NEW. 07-04)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: LongTermFirmPointToPointReservations
Contract MW amount.
(b) Concept: OtherService
Non Firm MW total for the peak hour.

FERC FORM NO. 1 (NEW. 07-04)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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).

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import 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)
	NAME OF SYSTEM: Enter System									
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: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2022-04-15	Year/Period of Report End of: 2021/ 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)	1,829,453
3	Steam	1,493,228	23	Requirements Sales for Resale (See instruction 4, page 311.)	123,021
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	1,205,349
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
7	Other	352,041	27	Total Energy Losses	241,279
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	1,845,269	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	3,399,102
10	Purchases (other than for Energy Storage)	1,526,190			
10.1	Purchases for Energy Storage				
11	Power Exchanges:				
12	Received	259,245			
13	Delivered	231,602			
14	Net Exchanges (Line 12 minus line 13)	27,643			
15	Transmission For Other (Wheeling)				
16	Received	7,676,047			
17	Delivered	7,676,047			
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	3,399,102			

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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).

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: Black Hills Power					
29	January	266,090	22,427	291	26	15
30	February	240,843	16,990	326	11	11
31	March	276,895	36,208	290	1	19
32	April	250,352	40,482	262	21	9
33	May	242,693	28,005	262	20	16
34	June	311,943	59,519	359	15	17
35	July	314,109	32,003	397	27	16
36	August	308,128	43,090	365	17	17
37	September	268,090	33,907	322	10	17
38	October	293,763	53,746	283	5	16
39	November	307,102	58,937	279	17	18
40	December	319,094	47,470	299	29	18
41	Total	3,399,102	472,784			

FERC FORM NO. 1 (ED. 12-90)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

Steam Electric Generating Plant Statistics

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.
9. Items under Cost of Plant are based on USofA 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.

Line No.	Item (a)	Plant Name: Ben French Diesel	Plant Name: Ben French Station	Plant Name: Neil Simpson CT #1	Plant Name: Neil Simpson Unit 2	Plant Name: [(a)] Wyodak
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Internal Combustion	Gas Turbine	Gas Turbine #1	Steam	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional	Conventional	Conventional	Conventional
3	Year Originally Constructed	1965	1977	2000	1995	1978
4	Year Last Unit was Installed	1965	1979	2000	1995	1978
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	10	100	40	90	81
6	Net Peak Demand on Plant - MW (60 minutes)	10	98	39	84	69
7	Plant Hours Connected to Load	6	299	2,576	7,689	7,793
8	Net Continuous Plant Capability (Megawatts)	10	80	38	80	67
9	When Not Limited by Condenser Water				80	67
10	When Limited by Condenser Water				80	67
11	Average Number of Employees				40	110
12	Net Generation, Exclusive of Plant Use - kWh	(425,470)	6,303,250	86,890,000	615,139	446,776,000
13	Cost of Plant: Land and Land Rights		52,680	1,000	117,401	109,191
14	Structures and Improvements		1,442,357	352,871	33,679,599	9,236,422
15	Equipment Costs	2,364,792	21,258,787	35,249,908	156,968,925	109,412,765
16	Asset Retirement Costs	(28,207)		(35,542)	(293,856)	(604,207)
17	Total cost (total 13 thru 20)	2,336,585	22,753,824	35,568,237	190,472,069	118,154,171

18	Cost per KW of Installed Capacity (line 17/5) Including	233.6585	227.5382	889.2059	2,116.3563	1,458.6935
19	Production Expenses: Oper, Supv, & Engr	13,126	227,207	106,360	337,536	603,540
20	Fuel	8,722	717,467	12,317,113	8,474,341	4,985,641
21	Coolants and Water (Nuclear Plants Only)					
22	Steam Expenses				700,417	631,473
23	Steam From Other Sources					
24	Steam Transferred (Cr)					
25	Electric Expenses	2,206	22,194	145,049	352,391	
26	Misc Steam (or Nuclear) Power Expenses				525,975	579,234
27	Rents			236,223	1,096,289	
28	Allowances					
29	Maintenance Supervision and Engineering	347	9,715		518,818	1,338
30	Maintenance of Structures			8,679	338,172	
31	Maintenance of Boiler (or reactor) Plant				2,777,755	1,457,520
32	Maintenance of Electric Plant	90,108	449,047	290,018	699,035	176,458
33	Maintenance of Misc Steam (or Nuclear) Plant				11,033	28,805
34	Total Production Expenses	114,509	1,425,630	13,103,442	15,831,762	8,464,009
35	Expenses per Net kWh	(0.2691)	0.2262	0.1508	25.7369	0.0189

35	Plant Name	Ben French Diesel	Ben French Station	Ben French Station	Neil Simpson CT #1	Neil Simpson Unit 2	Neil Simpson Unit 2	Wyodak
36	Fuel Kind	Oil	Gas	Oil	Gas	Coal	Gas	Coal
37	Fuel Unit	bbl	Mcf	bbl	Mcf	T	Mcf	T
38	Quantity (Units) of Fuel Burned	29	109,016	438.00	815,248	475,029	17,249	319,296
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	133,439	1,072	132,481	1,069	8,093	1,069	7,957
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	304.65	6.06	130.31	15.11	15.03	486.51	14.84
41	Average Cost of Fuel per Unit Burned	304.65	6.06	130.31	15.11	17.84	486.51	15.61
42	Average Cost of Fuel Burned per Million BTU	54.36	5.65	23.42	14.13	1.09	4.48	0.98
43	Average Cost of Fuel Burned per kWh Net Gen	(0.02)	0.09	(0.06)	0.14		0.01	0.01
44	Average BTU per kWh Net Generation	(377.000)			10,030.000	12,499.000		11,373.000

FERC FORM NO. 1 (REV. 12-03)

Page 402-403

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: PlantName

Wyodak is 20% owned by Black Hills Power.

FERC FORM NO. 1 (REV. 12-03)

Page 402-403

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

Hydroelectric Generating Plant Statistics

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.
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.

Line No.	Item (a)	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:
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)					
6	Net Peak Demand on Plant-Megawatts (60 minutes)					
7	Plant Hours Connect to Load					
8	**Net Plant Capability (in megawatts)**					
9	(a) Under Most Favorable Oper Conditions					
10	(b) Under the Most Adverse Oper Conditions					
11	Average Number of Employees					
12	Net Generation, Exclusive of Plant Use - kWh					
13	**Cost of Plant**					
14	Land and Land Rights					
15	Structures and Improvements					
16	Reservoirs, Dams, and Waterways					
17	Equipment Costs					
18	Roads, Railroads, and Bridges					
19	Asset Retirement Costs					
20	Total cost (total 13 thru 20)					
21	Cost per KW of Installed Capacity (line 20 / 5)					

22	**Production Expenses**					
23	Operation Supervision and Engineering					
24	Water for Power					
25	Hydraulic Expenses					
26	Electric Expenses					
27	Misc Hydraulic Power Generation Expenses					
28	Rents					
29	Maintenance Supervision and Engineering					
30	Maintenance of Structures					
31	Maintenance of Reservoirs, Dams, and Waterways					
32	Maintenance of Electric Plant					
33	Maintenance of Misc Hydraulic Plant					
34	Total Production Expenses (total 23 thru 33)					
35	Expenses per net kWh					

FERC FORM NO. 1 (REV. 12-03)

Page 406-407

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

Pumped Storage Generating Plant Statistics

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 that 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."
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.

Line No.	Item (a)	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:
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)				
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))				

FERC FORM NO. 1 (REV. 12-03)

Page 408-409

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 pumpec 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 statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Pa
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, i 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.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fue Cost (in cent (per Millic Btu (l)
									Fuel Production Expenses (i)	Maintenance Production Expenses (j)		
1	[(a)] Corriedale Wind Farm	2020	52.50	32.0	135,445,330	48,887,951		814,438			Wind	

FERC FORM NO. 1 (REV. 12-03)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: PlantName

The Corriedale Wind Farm is 62% owned by Black Hills Power.

FERC FORM NO. 1 (REV. 12-03)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

ENERGY STORAGE OPERATIONS (

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and locatio
3. In column (d), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In columns (e), (f) and (g) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (d) s
5. In columns (h), (i), and (j) report MWHs lost during conversion, storage and discharge of energy.
6. In column (k) report the MWHs sold.
7. In column (l), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the incor
8. In column (m), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If fuel costs for storage operations associated with self-generated power included in Account 501 and other costs associated with self-generated power
9. In columns (q), (r) and (s) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	MWHs (d)	MWHs delivered to the grid to support Production (e)	MWHs delivered to the grid to support Transmission (f)	MWHs delivered to the grid to support Distribution (g)	MWHs Lost During Conversion, Storage and Discharge of Energy Production (h)	MWHs Lost During Conversion, Storage and Discharge of Energy Transmission (i)	MWHs Lost During Conversion, Storage and Discharge of Energy Distribution (j)
1										
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
21										

22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32										
33										
34										

FERC FORM NO. 1 ((NEW 12-12))

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 kilov only for each voltage. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under
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 s
3. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. 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; c 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 the line.
5. 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 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 foo respect to such structures are included in the expenses reported for the line designated.
6. 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 y 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 oth
7. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, g 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 arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expe accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
8. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determ
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE Land, Land rig	
	From (a)	To (b)	Operating (c)	Designated (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)	(i)	Land (j)	Co
1	SOUTH DAKOTA										
2	Wyodak	Lookout	230.00	230.00	H-Wood	11.03		1	1272 KCM ACSR	9,800	
3	Lookout	Lange	230.00	230.00	H-Wood	54.53		1	1272 KCM ACSR	105,653	
4	Lange	West Hill	230.00	230.00	H-Wood	2.70		1	1272 KCM ACSR	465,310	
5	West Rapid Tap	West Rapid	230.00	230.00	SP-Steel	0.70		2	1272 KCM ACSR		
6	West Rapid Tap	South Rapid	230.00	230.00	H-Wood	5.30		1	1272 KCM ACSR		
7	South Rapid	West Hill	230.00	230.00	H-Wood	47.50		1	1272 KCM ACSR		
8	West Hill	Stegall	230.00	230.00	H-Wood	33.96		1	1272 KCM ACSR	17,701	
9	West Hill	Minnekahta	230.00	230.00	H-Wood	9.48		1	1272 KCM ACSR	11	
10	Minnekahta	Osage	230.00	230.00	H-Wood	23.32		1	1272 KCM ACSR	151,235	
11	Lange	Ben French	69.00	69.00	H-Wood	2.64	5.30	3	795 KCM ACSR		
12	(a) DC Tie West	South Rapid City	230.00	230.00	SP-Steel	4.00		1	1272 KCM ACSR	127,145	

13	[(b)] Osage	Yellowcreek	230.00	230.00	H-Wood	21.12		1	1272 KCM ACSR	1,533	
14	Osage	Lange	230.00	230.00	H-Wood	46.02		1	1272 KCM ACSR	1,512,324	[illegible]
15	WYOMING										
16	Wyodak	Lookout	230.00	230.00	H-Wood	73.26		1	1272 KCM ACSR	49,542	
17	Osage	Minnekahta	230.00	230.00	H-Wood	33.94		1	1272 KCM ACSR	96,159	
18	Osage	Wyodak	230.00	230.00	H-Wood	57.46		1	1272 KCM ACSR	162,516	
19	Neil Simpson I	Neil Simpson II	69.00	69.00	SP-Steel	0.80		1	795 KCM ACSR		
20	[(c)] Osage	Yellowcreek	230.00	230.00	H-Wood	22.02		1	1272 KCM ACSR	13,308	
21	Neil Simpson I	Wyodak	69.00	69.00	H-Wood	0.29		1	795 KCM ACSR		
22	Donkey Creek	Pumpkin Buttes	230.00	230.00	H-Wood	49.75	0	1	1272 KCM ACSR	1,280,649	
23	Wygen 3	Donkey Creek	230.00	230.00	SP-Steel	0.76		1	1272 KCM ACSR	3,488	
24	Pumpkin Buttes	Windstar	230.00	230.00	H-Steel	68.20		1	1272 KCM ACSR	2,204,210	[illegible]
25	[(d)] Windstar	Dave Johnston	230.00	230.00	H-Steel	2.56		1	1272 KCM ACSR		
26	Donkey Creek	Wyodak Tie Line #2	230.00	230.00	Steel	1.06		2	1272 KCM ACSR		
27	WY 1.14 Tap	Wyodak Baghouse	230.00	230.00	H-Wood	0.10		1	336.4 ACSR		
28	Teckla	Osage	230.00	230.00	H-Wood	81.55		1	1272 KCM ACSR	2,439,362	[illegible]
29	Osage	Lange	230.00	230.00	H-Wood	19.27		1	1272 KCM ACSR	589,324	[illegible]
30	NEBRASKA										
31	West Hill	Stegall	230.00	230.00	H-Wood	94.47		1	1272 KCM ACSR	329,367	[illegible]
36	TOTAL					767.79	5.30	32		9,558,637	[illegible]

FERC FORM NO. 1 (ED. 12-87)

Page 422-423

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: TransmissionLineStartPoint

DC Tie West to South Rapid City is 35% owned by Black Hills Power and 65% owned by Basin Electric.

(b) Concept: TransmissionLineStartPoint

Osage to Yellowcreek is 7.87% owned by Black Hills Power and 92.13% owned by Basin Electric.

(c) Concept: TransmissionLineStartPoint

Osage to Yellowcreek is 7.87% owned by Black Hills Power and 92.13% owned by Basin Electric.

(d) Concept: TransmissionLineStartPoint

Windstar to Dave Johnson is 56.25% owned by Black Hills Power and 43.75% owned by Pacificorp.

FERC FORM NO. 1 (ED. 12-87)

Page 422-423

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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 o
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-c 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 cha

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	Lanc and Lanc Right
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	West Rapid Tap	West Rapid	0.70	Steel	21	2	2	1272 ACSR	45/7	Vertical- Double Circuit	230	
2	Corriedale	West Cheyenne	0.55	DP- Wood	9	1	1	795 KCM ACSR		Horizontal	115	
44	TOTAL		1.25									

FERC FORM NO. 1 (REV. 12-03)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 cha 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 unattende page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capac
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole owner For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipme 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 partie and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Convers Spe
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)				Type of Equipment (i)
1	Anamosa, Rapid City, SD	Distribution	Unattended	69	12.47		20	1		Fans LTC
2	Argyle, SD	Distribution	Unattended	69	12.47		5	1		Fans
3	Belle Creek, MT	Distribution	Unattended	69	24.90		14	1		Fans
4	Ben French 26 Rapid City, SD	Distribution	Unattended	69	24.90		28	1		Fans. Regs
5	Butte Pipeline, Alzada, MT	Distribution	Unattended	69	2.40		13	3		
6	Cambell St, Rapid City, SD	Distribution	Unattended	69	12.47		14	1		Fans LTC
7	Cemetery, Rapid city, SD	Distribution	Unattended	69	12.47		28	2		Fans LTC
8	Century, Rapid City, SD	Distribution	Unattended	69	12.47		28	2		Fans LTC
9	Cleveland St. Rapid City, SD	Distribution	Unattended	69	12.47		25	1		Fans LTC
10	Cross Street, Rapid City, SD	Distribution	Unattended	69	12.47		14	1		Fans LTC
11	Colony Substation, Colony, WY	Distribution	Unattended	69	24.90		14	1		Fans
12	Custer, SD	Distribution	Unattended	69	12.47		11	1		Fans LTC
13	Custer, SD	Distribution	Unattended	69	24.90		11	1		Fans. Regs

14	East Meade, Rapid City, SD	Distribution	Unattended	69	12.47		20	1		Fans LTC
15	East North, Rapid City, SD	Distribution	Unattended	69	12.47		34	2		Fans LTC
16	Edgemont City, Edgemont, SD	Distribution	Unattended	69	12.47		14	1		Fans LTC
17	Fifth Street, Rapid City, SD	Distribution	Unattended	69	12.47		25	1		Fans LTC
18	Forty Fourth Street, Rapid City, SD	Distribution	Unattended	69	12.47		14	1		Fans LTC
19	Fourth Street, Rapid City, SD	Distribution	Unattended	69	4.16		21	2		Fans LTC
20	Hill City, SD	Distribution	Unattended	69	24.90		14	1		Fans
21	Hillsview, Spearfish, SD	Distribution	Unattended	69	12.47		14	1		Fans LTC
22	Hot Springs, SD	Distribution	Unattended	69	12.47		14	1		Fans LTC
23	Lange, Rapid City, SD	Distribution	Unattended	69	24.90		14	1		Fans
24	Mall, Rapid City, SD	Distribution	Unattended	69	24.90		14	1		Fans Regs
25	Merillat, Rapid City, SD	Distribution	Unattended	69	12.47		28	2		Fans LTC
26	Mountain View, Spearfish, SD	Distribution	Unattended	69	24.90		14	1		Fans Regs
27	Newcastle, WY	Distribution	Unattended	69	4.16		11	1		Fans Regs
28	Newell, SD	Distribution	Unattended	25	4.16		2	1		Fans Regs
29	Newell, SD	Distribution	Unattended	25	12.47		1	3		Fans
30	Neil Simpson ST 4160 East, Gillette, WY	Distribution	Unattended	69	4.16		14	1		Fans
31	Neil Simpson 4160 West, Gillette, WY	Distribution	Unattended	69	4.16		11	1		Fans
32	Osage, WY Osage City Sub Osage, WY	Distribution	Unattended	69	12.47		11	1		Fans
33		Distribution	Unattended	69	12.47		20	1		Fans LTC

	Pleasant Valley, Rapid City, SD									
34	Pluma, Deadwood, SD	Distribution	Unattended	69	12.47		21	2		Fans LTC
35	Rapid City South, Rapid City, SD	Distribution	Unattended	69	12.47		34	2		Fans LTC
36	Radio Drive Rapid City, SD	Distribution	Unattended	69	12.47		34	2		Fans LTC
37	Richmond Hill, Lead, SD	Distribution	Unattended	69	12.47		5	1		
38	Spearfish City, Spearfish, SD	Distribution	Unattended	69	12.47		14	1		Fans LTC
39	Spearfish Park, Spearfish, SD	Distribution	Unattended	69	12.47		14	1		Fans LTC
40	Spruce Gulch, Deadwood, SD	Distribution	Unattended	69	12.47		14	1		Fans LTC
41	Sturgis, SD	Distribution	Unattended	69	12.47		28	2		Fans LTC
42	Sundance Hill, Belle Fourche, SD	Distribution	Unattended	69	24.90		11	1		Fans Regs
43	Sundance Hill, Belle Fourche, SD	Distribution	Unattended	69	4.16		7	1		Fans LTC
44	Thirty Eight St., Rapid City, SD	Distribution	Unattended	69	12.47		14	1		Fans LTC
45	Trojan, Lead, SD	Distribution	Unattended	69	12.47		11	1		Fans LTC
46	Upton, WY Upton city Sub Upton, WY	Distribution	Unattended	69	2.40		3	1		Fans Regs
47	West Boulevard, Rapid City, SD	Distribution	Unattended	69	4.16		11	1		Fans LTC
48	West Hill, Hot Springs, SD	Distribution	Unattended	69	12.47		11	1		Fans Regs
49	Whitewood, SD	Distribution	Unattended	69	24.90		14	1		Fans Regs
50	Windy Flats, Nemo	Distribution	Unattended	69	12.47		7	1		Fans
51		Distribution	Unattended	69	24.90		10	1		Fans

	Portable Sub, Rapid City, SD									
52	Pactola, Rapid City, SD	Distribution	Unattended	69	24.90		9	1		Fans
53	Piedmont, Piedmont, SD	Distribution	Unattended	69	24.90		14	1		Fans, Regs
54	Ben French Diesels, Rapid City, SD	Transmission	Unattended	4	69.00		14	1		Fans
55	Ben French Combustion Turbines, Rapid City, SD	Transmission	Unattended	14	69.00		120	4		Fans & Pumps
56	Cambell ST./East Tie, Rapid City, SD	Transmission	Unattended	115	69.00		80	2		Fans & Pumps
57	Lange, Rapid City, SD	Transmission	Unattended	230	69.00	13.20	250	2		Fans & Pumps, LTC 40 MVAR Reac
58	Lange CT, Rapid City, SD	Transmission	Unattended	14	69.00		75	1		Fans
59	Lookout, Spearfish, SD	Transmission	Unattended	230	69.00	13.20	250	2		Fans & Pumps, LTC 40 MVAR Reac
60	Neil Simpson 2 Gillette, WY	Transmission	Unattended	14	69.00		150	1		Fans
61	Neil Simpson CT #1, Gillette, WY	Transmission	Unattended	14	69.00	13.20	84	1		Fans
62	Osage 230, Osage WY	Transmission	Unattended	230	69.00	13.20	70	1		Fans & Pumps, LTC 20 MVAR Reac
63	West Hill Hot Springs, SD	Transmission	Unattended	230	69.00	13.20	50	1		Fans & Pumps, LTC 20 MVAR Reac
64	Wyodak 69 Sub, Gillette, WY	Transmission	Unattended	230	69.00	13.20	100	1		Fans & Pumps, LTC 20 MVAR Reac
65	Yellow Creek, Lead, SD	Transmission	Unattended	230	69.00	13.20	250	2		Fans & Pumps, LTC 20 MVAR Reac
66		Transmission	Unattended	230	69.00		150	1		Fans LTC

	Rapid City South, Rapid City, SD									
67	Rapid City AC_DC_AC Tie Rapid City SD	Transmission	Unattended	230	230.00		218	4	1	Fans LTC, 90 MVAR Reac
68	Minnekahta Substation, Hot Springs, SD	Transmission	Unattended	230	69.00	13.20	70	1		Fans LTC, 20 MVAR Reac
69	Blucksberg, Sturgis, SD	Distribution	Unattended	69	24.90		20	1		Fans LTC
70	Sagebrush, Newcastle, WY	Transmission	Unattended	230	69.00	13.20	100	1		Fans LTC, 20 MVAR Reac
71	West Rapid City, Rapid City, SD	Transmission	Unattended	230	69.00	13.20	150	1		Fans LTC
72	Red Rock, Rapid City, SD	Distribution	Unattended	69	12.47		20	1		Fans LTC
73	Total									

FERC FORM NO. 1 (ED. 12-96)

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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 Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Customer Service	BHSC	Various	[(a)]1,807,142
3	Transmission	BHSC	Various	[(b)]10,702,502
4	Generation Dispatch & Pwr Mktg	BHSC	Various	[(c)]1,291,885
5	General Accounting	BHSC	Various	[(d)]2,723,825
6	Executive Management	BHSC	Various	[(e)]1,217,301
7	FERC Tariff & Compliance	BHSC	Various	[(f)]1,037,245
8	Regulatory & Governmental Affairs	BHSC	Various	[(g)]2,035,016
9	Environmental Services	BHSC	Various	[(h)]549,463
10	Finance & Treasury	BHSC	Various	[(i)]888,473
11	Information Technology	BHSC	Various	[(j)]8,822,097
12	Safety	BHSC	Various	[(k)]480,314
13	Power Delivery & Management	BHSC	Various	[(l)]574,296
14	Human Resources	BHSC	Various	[(m)]1,677,020
15	Communications	BHSC	Various	[(n)]719,309
16	Corporate Development	BHSC	Various	[(o)]316,816
17	Internal Audit	BHSC	Various	[(p)]416,526
18	Supply Chain Management	BHSC	Various	[(q)]4,443,728
19	Cheyenne Prairie Generating Station Plant Operations	BHSC	Various	[(r)]1,433,618
20	Legal	BHSC	Various	[(s)]5,388,766
21	Tax	BHSC	Various	[(t)]682,290
22	Credit & Risk	BHSC	Various	[(u)]254,363
23	Marketing & External Affairs	BHSC	Various	[(v)]353,924
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Neil Simpson Complex	CLFP	Various	[(w)]8,332,459

22	Environmental Complex	CLFP	Various	(x)124,805
23	Generation Dispatch & Pwr Mktg	CLFP	Various	(y)10,352
42				

FERC FORM NO. 1 ((NEW))

Name of Respondent: Black Hills Power, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Indirect charges were allocated based on Black Hills Service Company Allocation Manual.

(b) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Indirect charges were allocated based on Black Hills Service Company Allocation Manual.

(c) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Indirect charges were allocated based on Black Hills Service Company Allocation Manual.

(d) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Indirect charges were allocated based on Black Hills Service Company Allocation Manual.

(e) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Indirect charges were allocated based on Black Hills Service Company Allocation Manual.

(f) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Indirect charges were allocated based on Black Hills Service Company Allocation Manual.

(g) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Indirect charges were allocated based on Black Hills Service Company Allocation Manual.

(h) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Indirect charges were allocated based on Black Hills Service Company Allocation Manual.

(i) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Indirect charges were allocated based on Black Hills Service Company Allocation Manual.

(j) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Indirect charges were allocated based on Black Hills Service Company Allocation Manual.

(k) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Indirect charges were allocated based on Black Hills Service Company Allocation Manual.

(l) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Indirect charges were allocated based on Black Hills Service Company Allocation Manual.

(m) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Indirect charges were allocated based on Black Hills Service Company Allocation Manual.

(n) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Indirect charges were allocated based on Black Hills Service Company Allocation Manual.

(o) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Indirect charges were allocated based on Black Hills Service Company Allocation Manual.

(p) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Indirect charges were allocated based on Black Hills Service Company Allocation Manual.

(q) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Indirect charges were allocated based on Black Hills Service Company Allocation Manual.

(r) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Indirect charges were allocated based on Black Hills Service Company Allocation Manual.

(s) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Indirect charges were allocated based on Black Hills Service Company Allocation Manual.

(t) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Indirect charges were allocated based on Black Hills Service Company Allocation Manual.

(u) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Indirect charges were allocated based on Black Hills Service Company Allocation Manual.

(v) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Indirect charges were allocated based on Black Hills Service Company Allocation Manual.

(w) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies

Costs were allocated based on generating capacity.
(x) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies
Costs were allocated based on generating capacity.
(y) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies
Costs were allocated based on generating capacity.

FERC FORM NO. 1 ((NEW))