

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**

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

Exact Legal Name of Respondent (Company)

Black Hills Colorado Electric, LLC

Year/Period of Report
End of: 2025/ 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

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

- 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
- 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

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

"In connection with our regular examination of the financial statements of [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.

- 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>.
- 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:

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

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

- 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.
- 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.
- 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).
- 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.
- For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.
- Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.
- 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.
- 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 adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

- 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.
- 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 wit:

- '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;
- 'Person' means an individual or a corporation;
- '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;
- '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, utilizing, or distributing power;
- '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

- 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.

- 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

"Sec. 309.

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

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. § 825a(a).

**FERC FORM NO. 1
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER**

IDENTIFICATION

01 Exact Legal Name of Respondent Black Hills Colorado Electric, LLC		02 Year/ Period of Report End of: 2025/ 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) 105 South Victoria Avenue, Pueblo, CO 81003-0075		
05 Name of Contact Person Nick Wagner		06 Title of Contact Person Vice President Regulatory
07 Address of Contact Person (Street, City, State, Zip Code) 14103 Denver West Parkway, Suite 100, Lakewood, CO 80401-3124		
08 Telephone of Contact Person, Including Area Code (303) 566-3529	09 This Report is An Original / A Resubmission (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	10 Date of Report (Mo, Da, Yr) 12/31/2025

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 Courtney Hebert	03 Signature Courtney Hebert	04 Date Signed (Mo, Da, Yr) 04/02/2026
02 Title Vice President - Corporate Controller		

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 Colorado Electric, LLC

This report is:
(1) An Original
(2) A Resubmission

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ 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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
	Identification	1	
	List of Schedules	2	
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	Not applicable
4	Officers	104	
5	Directors	105	Not applicable
6	Information on Formula Rates	106	
7	Important Changes During the Year	108	
8	Comparative Balance Sheet	110	
9	Statement of Income for the Year	114	
10	Statement of Retained Earnings for the Year	118	
12	Statement of Cash Flows	120	
12	Notes to Financial Statements	122	
13	Statement of Accum Other Comp Income, Comp Income, and Hedging Activities	122a	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200	
15	Nuclear Fuel Materials	202	Not applicable
16	Electric Plant in Service	204	
17	Electric Plant Leased to Others	213	Not applicable
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224	Not applicable
22	Materials and Supplies	227	
23	Allowances and Environmental Credits	228	
24	Extraordinary Property Losses	230a	Not applicable
25	Unrecovered Plant and Regulatory Study Costs	230b	Not applicable
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250	Not applicable
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254b	Not applicable
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	
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	Not applicable
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	Not applicable
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	Not applicable
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	Not applicable
55	Distribution of Salaries and Wages	354	
56	Common Utility Plant and Expenses	356	Not applicable
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	Not applicable
61	Electric Energy Account	401a	
62	Monthly Peaks and Output	401b	
63	Steam Electric Generating Plant Statistics	402	
63.1	Renewable Generating Plant Statistics	404	Not applicable
64	Hydroelectric Generating Plant Statistics	406	Not applicable
65	Pumped Storage Generating Plant Statistics	408	
66	Generating Plant Statistics Pages	410	
66.1	Energy Storage Operations (Large Plants)	414	
66.2	Energy Storage Operations (Small Plants)	419	
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)		Not Prepared
	Stockholders' Reports Check appropriate box: <input type="checkbox"/> Two copies will be submitted <input type="checkbox"/> No annual report to stockholders is prepared		

Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
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Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ 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.

Courtney Hebert
Vice President - Corporate Controller
7001 Mt. Rushmore Rd., Rapid City, SD 57702

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

State of Incorporation: DE
Date of Incorporation: 2007-03-26
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:
(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 - Colorado

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 Colorado Electric, LLC

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Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ 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.

As of December 31, 2025, Black Hills Corporation owned 100% of the membership interests of Black Hills Electric Parent Holdings, LLC (BHEPH). BHEPH is the sole member and manager of Black Hills Colorado Electric, LLC.

Name of Respondent:
Black Hills Colorado Electric, LLC

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Date of Report:
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Year/Period of Report
End of: 2025/ 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)
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Name of Respondent:
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12/31/2025

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End of: 2025/ 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 and Chief Executive Officer	Linden R. Evans	1,000,000		
2	Sr. Vice President and Chief Financial Officer	Kimberly F. Nooney	490,000		
3	Sr. Vice President - Chief Information Officer	Erik D. Keller	413,000		2025-02-28
4	Sr. Vice President - Chief Human Resources Officer	Sarah A. Wiltse	364,000		
5	Sr. Vice President - Chief Utility Officer	Marne M. Jones	490,000		
6	Vice President Electric Operations	Campbell Hawkins	285,000		
7	Sr. Vice President and General Counsel	Phillip A. Casey	405,000		2025-04-01
8	Sr. Vice President - Chief Information and Transformation Officer	Don Reddent	390,000	2025-07-21	
9	Sr. Vice President - Chief Legal Officer and Corporate Secretary	Darren Nakata	430,000	2025-10-13	

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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)
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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	Open Access Transmission Tariff, Attachment H	Docket No. ER22-2185-000

Name of Respondent: Black Hills Colorado Electric, LLC	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2025	Year/Period of Report End of: 2025/ Q4
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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)?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
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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	20250228-5486	02/28/2025	ER25-1481-000	Informational Filing of 2025 Formula Rate Annual Update of Black Hills Colorado Electric, LLC under ER25-1481	Black Hills Colorado Attachment H-1 Formula Rate, Attachment H-2 Protocols

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				
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Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
(1) An Original
(2) A Resubmission

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ 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. See Schedule 122, Notes to Financial Statements, for information regarding the pending merger between Black Hills Corporation and Northwestern Energy as well as Black Hills Corporation's 2025 10-K Annual Report which was filed with the Security and Exchange Commission on February 11, 2025, for further information.

3. None

4. None

5. None

6. None

7. None

8. The average union wage increase for Colorado Electric for 2025 was 4.6%. The average non-union wage increase for Colorado Electric for 2025 was 5.3%.

9. See Schedule 122, Notes to Financial Statements, for information regarding legal proceedings culminating during the year ended December 31, 2025.

10. None

12. None

13. The following Director and Officer changes occurred during the period:

- Erik D. Keller, Senior Vice President – Chief Information Officer, resigned effective February 28, 2025.
- Katie Fleming was appointed to Vice President – Customer Experience and Chief Sustainability Officer effective March 31, 2025.
- Phillip A. Casey, Senior Vice President – Chief Legal Officer, General Counsel and Assistant Corporate Secretary was removed as an officer effective April 1, 2025.
- Amy K. Koenig, Vice President – Governance, Corporate Secretary and Deputy General Counsel, resigned effective May 1, 2025.
- Don Redden was appointed Senior Vice President – Chief Information and Transformation Officer effective July 21, 2025.
- Chris Herbers was appointed Vice President – Strategic Growth effective August 25, 2025.
- Darren Nakata was appointed Senior Vice President – Chief Legal Officer, Corporate Secretary and Chief Compliance Officer effective October 13, 2025.

14. None

Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
(1) An Original
(2) A Resubmission

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ 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	1,866,284,340	1,831,766,549
3	Construction Work in Progress (107)	200	35,670,621	36,365,646
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		1,901,954,961	1,868,132,195
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	622,372,392	583,434,168
6	Net Utility Plant (Enter Total of line 4 less 5)		1,279,582,569	1,284,698,027
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)		1,279,582,569	1,284,698,027
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		182,766	182,767
19	(Less) Accum. Prov. for Depr. and Amort. (122)		7,415	5,492
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224		
23	Noncurrent Portion of Allowances and Environmental Credits	228		
24	Other Investments (124)			
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)			
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)		175,351	177,275
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)			
36	Special Deposits (132-134)		7,569,199	7,293,458
37	Working Fund (135)			
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		18,729,215	15,692,452
41	Other Accounts Receivable (143)		25,270,041	4,910,581
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		491,318	410,723
43	Notes Receivable from Associated Companies (145)		30,349,283	11,632,203
44	Accounts Receivable from Assoc. Companies (146)		27,547,560	27,556,604
45	Fuel Stock (151)	227	408,586	446,621
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	13,854,677	11,655,068
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances and Environmental Credits (158.1, 158.2, 158.3, and 158.4)	228		
53	(Less) Noncurrent Portion of Allowances and Environmental Credits	228		
54	Stores Expense Undistributed (163)	227	906,025	713,582

55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		2,191,130	1,693,885
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)			
61	Accrued Utility Revenues (173)		16,640,797	14,031,127
62	Miscellaneous Current and Accrued Assets (174)			
63	Derivative Instrument Assets (175)			
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)		142,975,195	95,214,858
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)			
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	57,117,505	58,611,811
73	Prelim. Survey and Investigation Charges (Electric) (183)			
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)		816,102	155,141
76	Clearing Accounts (184)		4,086,641	781,924
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	231,794	893,153
79	Def. Losses from Disposition of Utility Pft. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)			
82	Accumulated Deferred Income Taxes (190)	234	70,780,524	76,686,825
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		133,032,566	137,128,854
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		1,555,765,681	1,517,219,014

Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
(1) An Original
(2) A Resubmission

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ 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		
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)			
7	Other Paid-In Capital (208-211)	253	426,981,943	418,981,943
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b		
11	Retained Earnings (215, 215.1, 216)	118	43,447,923	52,734,882
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118		
13	(Less) Reacquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)		
16	Total Proprietary Capital (lines 2 through 15)		470,429,866	471,716,825
17	LONG-TERM DEBT			
18	Bonds (221)	256		
19	(Less) Reacquired 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)			
24	Total Long-Term Debt (lines 18 through 23)			
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		131,347,451	149,260,230
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		20,582,714	803,776
29	Accumulated Provision for Pensions and Benefits (228.3)		4,939,732	4,902,000
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)			7
32	Long-Term Portion of Derivative Instrument Liabilities			
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		11,970,712	11,474,119
35	Total Other Noncurrent Liabilities (lines 26 through 34)		168,840,609	166,440,132
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)			
38	Accounts Payable (232)		17,748,671	16,089,872
39	Notes Payable to Associated Companies (233)		499,357,661	472,248,215
40	Accounts Payable to Associated Companies (234)		34,796,030	32,773,822
41	Customer Deposits (235)		2,797,928	2,191,018
42	Taxes Accrued (236)	262	13,554,583	11,792,707
43	Interest Accrued (237)		182,173	176,994
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		1,768,241	1,598,751
48	Miscellaneous Current and Accrued Liabilities (242)		6,989,231	8,624,504
49	Obligations Under Capital Leases-Current (243)		17,756,865	15,740,679
50	Derivative Instrument Liabilities (244)			
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)		594,951,383	561,236,562
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		10,091,146	9,711,011
57	Accumulated Deferred Investment Tax Credits (255)	266	2,961,135	3,133,477
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	176,310	123,071
60	Other Regulatory Liabilities (254)	278	115,374,988	103,401,765
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272		
63	Accum. Deferred Income Taxes-Other Property (282)		143,413,677	142,243,027
64	Accum. Deferred Income Taxes-Other (283)		49,526,567	59,213,144
65	Total Deferred Credits (lines 56 through 64)		321,543,823	317,825,495
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		1,555,765,681	1,517,219,014

32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		984,405	1,346,245															
33	Revenues From Nonutility Operations (417)		(177,909)																
34	(Less) Expenses of Nonutility Operations (417.1)		(2,734,697)	(922,447)															
35	Nonoperating Rental Income (418)																		
36	Equity in Earnings of Subsidiary Companies (418.1)	119																	
37	Interest and Dividend Income (419)		1,415,147	141,465															
38	Allowance for Other Funds Used During Construction (419.1)																		
39	Miscellaneous Nonoperating Income (421)		45,494	37,936															
40	Gain on Disposition of Property (421.1)		(431,847)	10															
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		4,287,189	1,677,690															
42	Other Income Deductions																		
43	Loss on Disposition of Property (421.2)																		
44	Miscellaneous Amortization (425)																		
45	Donations (426.1)		117,944	138,244															
46	Life Insurance (426.2)																		
47	Penalties (426.3)		1,266	121															
48	Exp. for Certain Civic, Political & Related Activities (426.4)		298,418	323,685															
49	Other Deductions (426.5)		3,099,593	413,530															
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		3,517,221	875,580															
51	Taxes Applic. to Other Income and Deductions																		
52	Taxes Other Than Income Taxes (408.2)	262	12,302	12,909															
53	Income Taxes-Federal (409.2)	262	(364,332)	393,170															
54	Income Taxes-Other (409.2)	262	(79,850)	86,170															
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	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		(431,880)	492,249															
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		1,201,848	309,861															
61	Interest Charges																		
62	Interest on Long-Term Debt (427)																		
63	Amort. of Debt Disc. and Expense (428)																		
64	Amortization of Loss on Required Debt (428.1)																		
65	(Less) Amort. of Premium on Debt-Credit (429)																		
66	(Less) Amortization of Gain on Required Debt-Credit (429.1)																		
67	Interest on Debt to Assoc. Companies (430)		26,021,368	25,440,803															
68	Other Interest Expense (431)		2,333,519	80,628															
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		856,985	1,053,649															
70	Net Interest Charges (Total of lines 62 thru 69)		27,497,902	24,467,782															
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		16,713,041	23,785,085															
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	0																
77	Extraordinary Items After Taxes (line 75 less line 76)																		
78	Net Income (Total of line 71 and 77)		16,713,041	23,785,085															

FOOTNOTE DATA

(a) Concept: IncomeTaxesOperatingIncome

Note: Below is the income tax as adjusted with the income tax effect of non-operating interest expense

Taxes as booked on FERC:	
Income Taxes- 409.1	2,026,754
Net Interest Expense - Total	27,497,901
Net Interest Expense Already Accounted for in Income Tax	(5,590,810)
Non-Operating Net Interest Expense Needing an Income Tax Adj	21,907,091
Remove Income Tax Effect of Non-Operating Interest Expense	(5,361,980)
Income Taxes- 409.1 As Adjusted	7,388,734

(b) Concept: IncomeTaxesUtilityOperatingIncomeOther

Note: Below is the income tax as adjusted with the income tax effect of non-operating interest expense

Taxes as booked on FERC:	
Income Taxes- 409.1	2,026,754
Net Interest Expense - Total	27,497,901
Net Interest Expense Already Accounted for in Income Tax	(5,590,810)
Non-Operating Net Interest Expense Needing an Income Tax Adj	21,907,091
Remove Income Tax Effect of Non-Operating Interest Expense	(5,361,980)
Income Taxes- 409.1 As Adjusted	7,388,734

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		52,734,882	37,199,797
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
10.1	Dividend to Parent		(26,000,000)	(8,250,000)
15	TOTAL Debits to Retained Earnings (Acct. 439)		(26,000,000)	(8,250,000)
16	Balance Transferred from Income (Account 433 less Account 418.1)		16,713,041	23,785,085
17	Appropriations of Retained Earnings (Acct. 436)			
17.1				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
23.1				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1				
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)		43,447,923	52,734,882
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
39.1				
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)		43,447,923	52,734,882
	UNAPPROPRIATED UNDISTRICTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
52.1				
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
(1) An Original
(2) A Resubmission

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ 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)	16,713,041	23,785,085
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	40,213,450	34,972,114
5	Amortization of (Specify) (footnote details)	1,034,379	964,053
5.1	Amortization of utility plant	543,467	493,625
5.2	Accretion Expense	490,912	470,428
8	Deferred Income Taxes (Net)	(4,180,793)	(920,107)
9	Investment Tax Credit Adjustment (Net)	(172,343)	(591,276)
10	Net (Increase) Decrease in Receivables	(4,574,827)	794,526
11	Net (Increase) Decrease in Inventory	(2,354,016)	(192,721)
12	Net (Increase) Decrease in Allowances and Environmental Credits Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	(2,153,882)	(5,814,795)
14	Net (Increase) Decrease in Other Regulatory Assets	13,815,661	12,302,139
15	Net Increase (Decrease) in Other Regulatory Liabilities		
16	(Less) Allowance for Other Funds Used During Construction		
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	(3,352,577)	6,099,462
18.1	Bad debt expense	1,335,211	1,241,989
18.2	Capital Lease Amortization	(2,748,647)	(933,601)
18.3	Employee benefit plan expense	449,040	406,945
18.4	Changes in other current and non-current assets	(5,910,126)	4,815,635
18.5	Changes in other current and non-current liabilities	(225,281)	568,494
18.6	Loss on Retirement of assets	431,847	
18.7	Change in Regulatory Assets and Liabilities Impacting Income Statement	3,315,379	
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	54,988,093	71,398,480
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(45,359,418)	(64,999,718)
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	856,985	1,053,649
31	Other (provide details in footnote):	1,221,132	938,680
31.1	Cost of removal net of salvage	914,194	644,495
31.2	Contributions in Aid of Construction	306,938	294,185
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(44,995,271)	(65,114,687)
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 and Environmental Credits Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1			
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(44,995,271)	(65,114,687)
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			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):	27,000,000	17,050,000
67.1	Net change in Note Payable to Parent	27,000,000	17,050,000
70	Cash Provided by Outside Sources (Total 61 thru 69)	27,000,000	17,050,000
72	Payments for Retirement of:		
73	Long-term Debt (b)		
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	(36,717,081)	(22,446,875)
76.1	Dividends to Parent	(18,000,000)	(1,250,000)
76.2	Net payments to Money Pool	(18,717,081)	(21,196,875)
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)	(9,717,081)	(5,396,875)
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)	275,741	886,918
88	Cash and Cash Equivalents at Beginning of Period	7,293,458	6,406,540
90	Cash and Cash Equivalents at End of Period	7,569,199	7,293,458

Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
(1) An Original
(2) A Resubmission

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ 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 Commission 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, where 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.

NOTES TO THE FINANCIAL STATEMENTS

(1) BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Colorado Electric, LLC, doing business as Black Hills Energy ("Colorado Electric", the "Company", "we", "us", or "our") is a regulated electric utility serving customers in Colorado. We are an indirect 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 Colorado Electric, LLC and also our ownership interests in the assets, liabilities and expenses of our jointly owned facilities (Note 6).

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) and contemplates the realization of assets and the satisfaction of liabilities in the normal course of business. Additionally, these requirements differ from GAAP related to the presentation of certain items discussed below.

The Company has experienced negative cash flows, insufficient liquidity, and working capital to fund operations. The Company is also dependent upon financial support from its Parent in order to obtain and renew debt financing. As of December 31, 2025, the Company had \$497.4 million of outstanding short-term Notes payable to Parent. These conditions and events raise substantial doubt about the Company's ability to continue as a going concern.

In response to these conditions, the Company's Parent, has committed to fully support the Company's operating, investing, and financing activities to enable the Company to meet its obligations as they become due for at least one year following the date that the financial statements were available to be issued. As a result, the Company has concluded that management's plans are probable of being achieved to alleviate substantial doubt about the Company's ability to continue as a going concern.

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.
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.
Deficient and excess deferred income taxes, which represent the revaluation of the regulated utilities' deferred tax assets and liabilities due to the passage of the Tax Cuts and Jobs Act (TCJA), are classified as gross regulatory assets and liabilities, respectively, for FERC reporting. GAAP presentation reflects either a net regulatory 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.
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. Therefore, we record a regulatory asset/liability for GAAP associated with the portion of such costs. 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.
FERC includes all payments for leases, regardless of classification, within operating activities for the Statement of Cash Flows. In contrast, GAAP bifurcates payments between financing and operating activities for finance leases.
For FERC reporting, our capital lease payments to Black Hills Colorado IPP (see Note 10) are required to be charged to purchased power as they become payable. Under GAAP ASC 842, for finance leases, amortization of the ROU (Right of Use) asset must be included with depreciation expense and interest expense classified with similar interest expense amounts.
Goodwill (plant acquisition adjustments) is included within utility plant for FERC reporting but is presented as other non-current assets for GAAP reporting.

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.

Cash, Special Deposits and Cash Equivalents

We consider all highly liquid investments with original maturity of three months or less to be cash equivalents. We maintain cash accounts for various specified purposes, which are classified as special deposits. As of December 31, 2025, and 2024, 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 natural gas and 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. Typically, our customers are billed monthly with payment due within 20 days. Any fixed consideration contracts with an expected duration of one year or more are immaterial to our revenues. Variable consideration 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 4 include our revenue accounted for under separate accounting guidance, including lease revenue under ASC 842, Leases, derivative revenue under ASC 815, Derivatives and Hedging, and alternative revenue programs revenue under ASC 980, Regulated Operations.

Significant Judgments and Estimates

Unbilled Revenue

To the extent that deliveries have occurred but a bill has not been issued, 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 true-up and recorded in Accrued Utility Revenues (Account 173) on the accompanying Balance Sheets.

Contract Balances

The nature of substantially all of our revenue contracts provides an unconditional right to consideration upon service delivery. Customer billings (and subsequent customer payments of those bills) occur after service delivery. Therefore, customer contract assets or liabilities do not exist. The unconditional right to consideration is represented by the balance in our Accounts Receivable, which is further discussed below.

See Note 4 for additional information.

Accounts Receivable and Allowance for Credit Losses

Accounts receivable are stated at billed amounts, net of allowance for credit losses, and do not bear interest. 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 collectability.

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 (Account 144) for the years ended December 31, were as follows (in thousands):

Table with 5 columns: Year, 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. Rows for 2025 and 2024.

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. Debt discounts, premiums, and deferred financing costs are amortized as interest expense on a basis that approximates the effective interest method over the term 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 13.

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 other comprehensive income (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.

See Note 2 for additional information.

Property, Plant and Equipment

Property, plant and equipment is stated at cost, which includes construction-related direct labor and material costs, indirect construction costs including labor and related costs of departments associated with supporting construction activities, and allowance for funds used during construction (AFUDC). Additions to and significant replacements of property are charged to property, plant and equipment at cost. Ordinary repairs and maintenance of property, except as allowed under rate regulations, are charged to operations as incurred.

We also capitalize interest, when applicable, on undeveloped leasehold costs. 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 Utility plant on the accompanying Balance Sheets.

We receive contributions in aid of construction (CIACs) from third parties that are generally intended to defray all or a portion of the costs for certain capital projects. Such CIAC costs are recorded as a reduction to Construction work in progress.

The cost of regulated Utility plant retired, or otherwise disposed of in the ordinary course of business, less salvage plus retirement costs, is charged to accumulated provision for depreciation. Retirement or disposal of all other assets result in gains or losses recognized as a component of Other Income. Ordinary repairs and maintenance of property, except as allowed under regulations, are charged to operations as incurred.

Depreciation

Depreciation provisions for property, plant and equipment are generally computed on a straight-line basis based on the applicable estimated service life of the various classes of property. The composite depreciation method is applied to regulated utility property. Depreciation studies are conducted periodically to update composite rates and are approved by the state utility commission and/or the FERC when required.

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 2025 and 2024.

AFUDC

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.

Plant Acquisition Adjustments

Plant acquisition adjustments with indefinite lives are not amortized, but the carrying values are reviewed upon an indicator of impairment or at least annually.

Plant acquisition adjustments relate to our acquisition by BHC and represents the final purchase allocation of the cost of the investment over the book value of the underlying net assets acquired. We perform an impairment test on an annual basis or upon the occurrence of events or changes in circumstances that indicate that the asset might be impaired. Our annual impairment testing date is as of October 1, which aligns our testing date with our financial planning process. No impairment loss was recorded during 2025 or 2024.

As of December 31, 2025, and 2024, our plant acquisition adjustments balance was \$234.8 million.

Asset Retirement Obligation

Accounting standards for AROs associated with long-lived assets require that the present value of retirement costs for which we have a legal obligation be recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriated period. The accounting for the obligation has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset or a regulatory liability.

We initially record liabilities for the present value of retirement costs for which a legal obligation exists, with an equivalent amount added to the asset cost. The asset is then depreciated or depleted over the appropriate useful life and the liability is accreted over time by applying an interest method of allocation. Any difference in the actual cost of the settlement of the liability and the recorded amount is recognized as a gain or loss in the results of operations.

See Note 13 for additional information.

Fair Value Measurements

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

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

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

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

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels. We record transfers, if necessary, between levels at the end of the reporting period for all of our financial instruments.

Transfers into Level 3, if any, occur when significant inputs used to value the derivative instruments become less observable, such as a significant decrease in the frequency and volume in which the instrument is traded, negatively impacting the availability of observable pricing inputs. Transfers out of Level 3, if any, occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery date of a transaction becomes 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 7 and 8.

Income Taxes

We are subject to federal and state 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 have elected to account for transferable renewable tax credits, including PTCs and ITCs, as a reduction to income taxes payable under the scope of ASC 740 *Income Taxes*. We include the discount from the sale of our tax credits as a component of income tax expense. The sale of tax credits is presented within Operating activities in the Statement of Cash Flows consistent with the presentation of cash taxes paid. For renewable tax credits subject to future transfer, a valuation allowance is recorded for the difference between the tax value of the credits and the expected sales price. Tax credits and any related valuation allowances are derecognized when control of the tax credits is transferred to other corporate taxpayers. See Notes 3 and 9 for further discussion of the transfer of renewable tax credits to other corporate taxpayers, including related indemnification requirements and valuation allowances, respectively.

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.

Pension and Other Postretirement Plans

We recognize on our Balance Sheets an asset or liability reflecting the funded status of pension and other postretirement plans with current-year changes in actuarial gains or losses recognized in regulatory assets or liabilities. All plan assets are recorded at fair value. We follow the measurement date provisions of ASC 715, *Compensation-Retirement Benefits*, which require a year-end measurement date of plan assets and obligations for all defined benefit plans.

Recently Adopted Accounting Standards

Improvements to Income Tax Disclosures, ASU 2023-09 - In December 2023, the Financial Accounting Standards Board (FASB) issued ASU 2023-09, *Improvements to Income Tax Disclosures*, which expands public entities' annual disclosures by requiring disclosure of tax rate reconciliation amounts and percentages for specific categories, income taxes paid disaggregated by federal and state taxes, and income tax expense disaggregated by federal and state tax jurisdiction. We implemented this ASU effective for our Annual Report for the year ended December 31, 2025. Adoption of this ASU did not have a material impact on our consolidated financial statement disclosures. The additional disclosures required by this ASU are in Note 9.

(2) REGULATORY MATTERS

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

	2025		2024
Regulatory assets			
Employee benefit plans and related deferred taxes ^(b)	\$	11,269	\$ 11,223
Decommissioning costs ^(a)		2,476	2,407
Deficient deferred income taxes ^(b)		38,959	39,598
Other regulatory assets ^(a)		4,414	5,384
Total Other Regulatory Assets (182.3)	\$	57,118	\$ 58,612
Regulatory liabilities			
Deferred energy and fuel cost adjustments ^(a)	\$	7,937	\$ 3,163
Employee benefit plans and related deferred taxes ^(b)		5,173	5,120
Excess deferred income taxes ^(b)		67,725	69,872
Renewable energy standard adjustment ^(a)		33,176	24,072
Other regulatory liabilities ^(b)		1,364	1,175
Total Other Regulatory Liabilities (254)	\$	115,375	\$ 103,402

(a) Recovery/repayment of costs, but we are not allowed a rate of return.

(b) In addition to recovery or repayment of costs, we are allowed a return on a portion of this amount or a reduction in rate base.

Regulatory assets represent items we expect to recover from customers through probable future rates.

Deferred Energy and Fuel Cost Adjustments - Deferred energy and fuel cost adjustments represent the cost of electricity delivered to our 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 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 state utility commission. The recovery period is less than a year.

Employee Benefit Plans and Related Deferred Taxes - Employee benefit plans include the unrecognized prior service costs and net actuarial loss associated with our defined 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 in accordance with ASC 715, *Compensation-Retirement Benefits*, to record the full pension and post-retirement benefit obligations. Such income tax effect has been grossed-up to account for the revenue requirement associated with a rate regulated environment.

Decommissioning Costs - We received approval in 2014 for regulatory treatment of costs to decommission our coal plants. The recovery of these costs will be determined in a future rate review.

Deficient Deferred Income Taxes - See Excess Deferred Income Taxes discussion below for information. Regulatory liabilities represent items we expect to refund to customers through probable future decreases in rates.

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

Deferred Energy and Fuel Cost Adjustments - Deferred energy and fuel costs that have been over-recovered through customer rates and will be returned to customers in future periods.

Employee Benefit Plans and Related Deferred Taxes - Employee benefit plans represent the cumulative excess of pension and retiree healthcare costs recovered in rates over pension expense recorded in accordance with accounting standards for compensation - retirement benefits. In addition, this regulatory liability includes the income tax effect of the adjustment required under accounting for compensation - defined benefit plans, to records the full pension and post-retirement benefit obligations. Such income tax effect has been grossed-up to account for the revenue requirement associated with a rate regulated environment.

Excess Deferred Income Taxes - The revaluation of the regulated utilities' deferred tax assets and liabilities due to the passage of the TCJA was recorded as deficient (regulatory asset) and excess (regulatory liability) deferred income taxes. The net regulatory liability amount will be refunded to customers primarily using the normalization principles as prescribed in the TCJA.

Renewable Energy Standard Adjustment - The renewable energy standard adjustment is an incremental retail rate limited to 2% (1.5% effective January 1, 2025) for Colorado Electric customers that provides funding for various renewable energy projects and programs to comply with Colorado's Renewable Energy Standard. These programs include incentives for customers to install renewable energy equipment at their location. These project costs and program incentives are recovered over time through the Renewable Energy Standard Adjustment charged on customers' bills. Project costs that are over-recovered through customer rates will be refunded to customers in future periods.

Regulatory Activity

Clean Energy Plan

In March 2023, the Colorado Public Utilities Commission ("CPUC") approved a unanimous settlement for Colorado Electric's Clean Energy Plan filed May 25, 2022, with the CPUC. The Clean Energy Plan establishes a roadmap and preferred resource portfolio for Colorado Electric to cost-effectively achieve the State of Colorado's requirement calling upon electric utilities to reduce GHG emissions by a minimum of 80% by 2030. In July 2023, Colorado Electric issued a request for proposals for new renewable resources to be in service by 2029 to achieve objectives in its Clean Energy Plan. On April 17, 2024, Colorado Electric filed its 120-Day report with the CPUC, recommending the addition of renewable energy resources to advance its Clean Energy Plan. In 2025, CPUC approval was received for the addition of 250 MWs of renewable generation resources in support of the Clean Energy Plan, including a 50-MW battery storage project and a 200-MW solar PPA. On November 3, 2025, the CPUC approved the Certificate of Public Convenience and Necessity ("CPCN") for the 50-MW battery storage project. Colorado Electric expects to execute the 200-MW solar PPA during the first quarter of 2026.

Rate Review

On June 14, 2024, Colorado Electric filed a rate review with the CPUC seeking recovery of infrastructure investments in its 3,200-mile electric distribution and 600-mile electric transmission systems. On March 17, 2025, Colorado Electric received an order from the CPUC for a general rate increase which was expected to generate approximately \$17.0 million of new annual revenue based on a weighted average cost of capital of 6.9% with a capital structure in a range of 47% to 49% equity and 51% to 53% debt, and a return on equity in a range of 9.3% to 9.5%. The new rates were effective March 22, 2025. On April 7, 2025, Colorado Electric filed a request with the CPUC for rehearing, re-argument or reconsideration ("RRR"). On May 6, 2025, Colorado Electric received a final decision from the CPUC related to its RRR request, increasing new annual revenue from approximately \$17.0 million to approximately \$17.5 million.

(3) COMMITMENTS AND CONTINGENCIES

Unconditional Purchase Obligations

We have a power purchase agreement with a third party which extends to 2030, to support our capacity and energy needs beyond our power plants' generation. We currently do not have any unconditional purchase obligations required under this power purchase agreement since it is derived from renewable energy and vary based on weather conditions.

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.

Reclamation Liability

For our Pueblo Airport Generation site, we posted a bond with the State of Colorado to cover the costs of remediation for a waste water containment pond permitted to provide wastewater storage and processing for this zero discharge facility. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land.

Under our land leases for our wind generation facilities, we are required to reclaim all land where we have placed wind turbines. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land.

See Note 13 for additional information.

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 estimate 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.

Deborah Ferrari et al. v. Colorado Electric, Case No. 2024CV31889 (District Court for the City and County of Denver, Colorado)

During the year ended December 31, 2025, Colorado Electric settled a legal matter involving an auto accident. As part of the settlement, Colorado Electric recognized a legal liability of \$20.0 million, which is included in Accrued liabilities on the Consolidated Balance Sheets as of December 31, 2025.

In connection with this matter, Colorado Electric also recognized a loss recovery receivable of \$20.0 million under its insurance coverage, which management determined is probable of collection based on confirmation from the insurer and policy terms. The receivable is presented in Other current assets on the Consolidated Balance Sheet as of December 31, 2025. The liability and receivable are presented gross, as we do not have an enforceable legal right of set-off and do not intend net settlement.

The settlement and recovery were both recognized in the same reporting period, resulting in no material net impacts on the Consolidated Statements of Income for the year ended December 31, 2025. We do not expect additional material losses related to this matter. We expect to pay the legal liability and receive the insurance receivable in 2026.

Indemnification

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.

Transfers of Renewable Tax Credits

In June 2024 and January 2025 we entered into agreements with a third party to sell our 2023 and 2024 generated PTCs, respectively. In January 2026, we entered into a similar agreement with the same third party to sell our 2025 generated PTCs. In each of these agreements, we provided indemnifications associated with the proceeds for PTCs transferred to the third party in the event of an adverse interpretation of tax law, including whether the related tax credits meet the qualification requirements. Additionally, in our agreement for the sale of our 2024 and 2025 generated PTCs, we provided indemnifications in the event of a change in tax law. We believe the likelihood of having to make any material cash payments under these indemnifications is remote. See Note 9 for additional information.

(4) REVENUE

The following table depicts the disaggregation of revenue from contracts with customers by customer type and timing of revenue recognition (in thousands). Sales tax and other similar taxes are excluded from revenues.

Customer types:	Year ended December 31,		
	2025	2024	
Retail	\$	259,143	\$ 243,115
Wholesale		3,902	7,046
Market-off-system sales		9,950	8,065
Transmission/Other		7,359	14,783
Revenue from contracts with customers		280,354	273,009
Other revenues		261	158
Total Revenues	\$	280,615	\$ 273,167
Timing of revenue recognition:			
Services transferred over time	\$	280,354	\$ 273,009
Revenue from contracts with customers	\$	280,354	\$ 273,009

(5) PROPERTY, PLANT AND EQUIPMENT

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

FERC Accounts	2025	2025 Weighted Average Useful Life (in years)		2024 Weighted Average Useful Life (in years)		Lives (in years)	
		2024	Minimum	Maximum	Minimum	Maximum	
Electric plant:							
Production	\$ 437,774	32	\$ 433,594	32	25	50	
Transmission	340,519	51	335,078	48	15	60	
Electric distribution	504,332	55	484,307	50	15	65	
Plant acquisition adjustment ^(a)	234,762	N/A	234,762	N/A	N/A	N/A	
General	86,533	16	83,467	23	5	29	
Capital lease - plant in service ^(b)	261,441	6	261,441	7	6	6	
Operating lease assets	923		940				
Total plant-in-service	1,866,284		1,833,589				
Construction work-in-progress	107		36,366				
Total electric plant	1,901,955		1,869,955				
Less accumulated depreciation and amortization	108, 110, 111, 115	(622,372)	(585,257)				
Electric plant net of accumulated depreciation and amortization	\$ 1,279,583		\$ 1,284,698				

(a) The plant acquisition adjustment relates to our acquisition by BHC and is not included in rate base. See Note 1 for additional information.

(b) Capital lease - plant in service represents the assets accounted for as a capital lease under the Power Purchase Agreement (PPA) between us and Black Hills Corporation IPP. The capital lease ends in conjunction with the expiration of the PPA on December 31, 2031. See Notes 10 and 11 for additional information.

(6) JOINTLY OWNED FACILITIES

Our financial statements include our share of several jointly-owned utility and non-regulated facilities as jointly 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.

Busch Ranch I

Colorado Electric owns 50% of Busch Ranch I, a 29 MW wind farm near Pueblo, Colorado, while Black Hills Electric Generation owns the remaining 50% ownership interest. Each company is obligated to make payments for costs associated with their proportionate share of the costs of operating the wind farm over the life of the facility. Colorado Electric retains responsibility for operations of the wind farm. Black Hills Electric Generation provides its share of energy from the wind farm to Colorado Electric through a PPA, which expires in October 2037. For the years ended December 31, 2025 and 2024, we allocated net costs of \$0.4 million and \$0.6 million, respectively, to Black Hills Electric Generation.

As of December 31, 2025, our interests in jointly-owned generating facilities was (in thousands):

Interest in jointly-owned facilities	Ownership Interest	Plant In Service	Construction Work in Progress	Less Accumulated Depreciation	Plant Net of Accumulated Depreciation
Busch Ranch I Wind Farm	50%	\$ 19,757	\$ 103	\$ (10,376)	\$ 9,484

(7) 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 8.

Other fair value measures

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

(8) 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, 2025, the expected rate of return on pension plan assets was based on the targeted asset allocation range of 26% to 34% return-seeking assets and 66% to 74% 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:

	2025	2024
Return-seeking Assets		
Equity	19%	19%
Real estate	5%	5%
Hedge funds	2%	3%
Fixed income	3%	3%
Total	29%	30%
Liability-hedging Assets		
Fixed income	69%	68%
Cash	2%	2%
Total	71%	70%
Total assets	100%	100%

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 Colorado Electric 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):

	2025	2024
Defined Contribution Plans		
Company Retirement Contribution	\$ 606	\$ 620
Matching Contributions	\$ 940	\$ 985
Defined Benefit Plans		
Pension Plan	\$ 140	\$ 190
Healthcare Plan	\$ 241	\$ 149

We do not have any required 2026 contributions, however, we expect to contribute \$0.1 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):

	December 31, 2025			December 31, 2024		
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV ^(a)	Total Fair Value
Pension Plan						
Recurring Fair Value Measures						
Common Collective Trust - Cash and Cash Equivalents	\$ -	\$ 486	\$ -	\$ 486	\$ -	\$ 486
Common Collective Trust - Equity	-	4,034	-	4,034	-	4,034
Common Collective Trust - Fixed Income	-	15,261	-	15,261	-	15,261
Common Collective Trust - Real Estate	-	-	-	-	1,147	1,147
Hedge Funds	-	-	-	-	389	389
Total investments measured at fair value	\$ -	\$ 19,781	\$ -	\$ 19,781	\$ 1,536	\$ 21,317
Pension Plan						
Recurring Fair Value Measures						
Common Collective Trust - Cash and Cash Equivalents	\$ -	\$ 423	\$ -	\$ 423	\$ -	\$ 423
Common Collective Trust - Equity	-	4,011	-	4,011	-	4,011
Common Collective Trust - Fixed Income	-	14,868	-	14,868	-	14,868
Common Collective Trust - Real Estate	-	-	-	-	1,158	1,158
Hedge Funds	-	-	-	-	590	590
Total investments measured at fair value	\$ -	\$ 19,302	\$ -	\$ 19,302	\$ 1,748	\$ 21,050

(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 Pension 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 Pension 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.

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 Funds: These funds are valued based on various factors of the underlying real estate properties, including market rent, market rent growth, occupancy levels, etc. As part of the trustee's valuation process, properties are externally appraised generally on an annual basis. The appraisals are conducted by reputable independent appraisal firms and signed by appraisers that are members of the Appraisal Institute, with professional designation of Member, Appraisal Institute. All external appraisals are performed in accordance with the Uniform Standards of Professional Appraisal Practices. We receive monthly statements from the trustee, along with the annual schedule of investments and rely on these reports for pricing the units of the fund.

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.

Components of Net Periodic Expense

The following table provides a reconciliation of components of the net periodic expense (in thousands):

For the year ended December 31,	Pension Plan		Healthcare Plan	
	2025	2024	2025	2024
Service cost	\$ 60	\$ 84	\$ 67	\$ 72
Interest cost	1,231	1,334	109	108
Expected return on assets	(1,317)	(1,473)	-	-
Amortization of prior service cost	3	3	-	-
Amortization of (gain)	-	-	(4)	-
Recognized net actuarial loss	300	279	-	-
Net periodic expense	\$ 277	\$ 227	\$ 172	\$ 180

Actuarial gains and losses are amortized using a straight-line method over the average remaining service period of active plan participants or over the average remaining lifetime of the remaining plan participants if the plan is viewed as "all or almost all" inactive participants.

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 and accumulated benefit obligation (in thousands):

As of December 31,	Pension Plan		Healthcare Plan	
	2025	2024	2025	2024
Accumulated benefit obligation at December 31	\$ 24,230	\$ 23,928	\$ 2,113	\$ 2,207
Change in benefit obligation:				
Projected benefit obligation at beginning of year	\$ 24,034	\$ 28,398	\$ 2,207	\$ 2,347
Service cost	60	84	67	72
Interest cost	1,231	1,334	109	108
Actuarial loss (gain)	1,229	(2,304)	(30)	(147)
Benefits paid	(2,144)	(3,478)	(241)	(149)
Plan participants transfer to affiliate	-	-	(12)	(34)
Plan participants' contributions	-	-	13	10
Projected benefit obligation at end of year	\$ 24,410	\$ 24,034	\$ 2,113	\$ 2,207
Change in fair value of plan assets:				
Beginning fair value of plan assets	\$ 21,050	\$ 25,434	\$ -	\$ -
Investment income (loss)	2,270	(1,096)	-	-
Benefits paid	(2,144)	(3,478)	(241)	(149)
Participant contributions	-	-	13	10
Employer contributions	140	190	228	139
Ending fair value of plan assets	\$ 21,316	\$ 21,050	\$ -	\$ -
Funded status - deficiency	\$ 3,094	\$ 2,984	\$ 2,113	\$ 2,207
Amounts recognized on our Balance Sheets as of December 31:				
Other Regulatory Assets (192.3)	\$ 10,659	\$ 10,686	\$ -	\$ -
Miscellaneous Current and Accrued Liabilities (242)	-	-	269	283
Accumulated Provision for Pensions and Benefits (228.3)	3,093	2,984	1,844	1,924
Other Regulatory Liabilities (254)	-	-	1,696	1,657

In 2012, we froze our Pension Plan and closed it to new participants. Since then, we have implemented various de-risking strategies including lump sum buyouts, the purchase of annuities and the reduction of return-seeking assets over time to a more liability-hedged portfolio. As a result, capital markets volatility had a limited impact to our unfunded status.

Assumptions

Weighted-average assumptions used to determine benefit obligations:	Pension Plan		Healthcare Plan	
	2025	2024	2025	2024
Discount rate	5.38%	5.63%	5.32%	5.60%
Rate of increase in compensation levels	3.01%	3.04%	N/A	N/A
Weighted-average assumptions used to determine net periodic benefit cost for plan year:				
Discount rate ^(a)	5.63%	4.99%	5.60%	4.97%
Expected long-term rate of return on assets ^(b)	6.50%	6.00%	4.10%	3.50%
Rate of increase in compensation levels	3.04%	3.04%	N/A	N/A

(a) The estimated discount rate for the Defined Benefit Pension Plan is 5.38% for the calculation of the 2025 net periodic pension costs.

(b) The expected rate of return on Defined Benefit Pension Plan assets is 6.50% for the calculation of the 2025 net periodic pension costs.

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

	2025	2024
Trend Rate - Medical		
Pre-65 for next year - All plans	7.00%	7.50%
Pre-65 Ultimate trend rate	4.50%	4.50%
Trend Year	2035	2035
Post-65 for next year - all plans	6.00%	6.50%
Post-65 Ultimate trend rate	4.50%	4.50%
Trend Year	2035	2033

Estimated Future Benefit Payments

The following benefit payments, which reflect future service, are expected to be paid (in thousands):

	Pension Plan	Healthcare Plan
2026	\$ 2,147	\$ 269
2027	\$ 2,204	\$ 261
2028	\$ 2,171	\$ 239
2029	\$ 2,169	\$ 243

(9) INCOME TAXES**Transfers of Production Tax Credits**

In August 2022, H.R. 5376, commonly known as the IRA of 2022, or IRA, was enacted. The IRA contains a tax credit transferability provision that allows us to transfer (e.g. sell) PTCs produced after December 31, 2022, to third parties. In June 2024 and January 2025, under this transferability provision, we entered into an agreement with a third party to sell 2023 generated PTCs for \$4.9 million and 2024 generated PTCs for \$5.3 million. In January 2026, we entered into a similar agreement to sell 2025 generated PTCs for \$5.2 million.

We expect to continue to explore the ability to efficiently monetize our tax credits through third party transferability agreements.

One Big Beautiful Bill Act

In July 2025, H.R. 1, commonly referred to as the OBCCA, was enacted. The OBCCA is a legislative package designed to permanently extend certain expiring provisions of the TCJA and deliver additional tax relief for individuals and businesses. The OBCCA introduced changes to federal energy policies by rolling back several clean energy provisions and codified restrictions related to prohibited foreign entities, termination and restrictions on clean energy PTCs, and extensions and modification of clean fuel production. The OBCCA does not repeal tax credit transferability provisions enacted under the IRA and continues to permit the execution of our transferability agreements as originally agreed upon, but restricts credits transfers to prohibit foreign entities.

Additionally, on August 15, 2025, the IRS issued Notice 2025-42, which provides guidance on the beginning of construction requirements for applicable wind and solar. These requirements are critical for determining eligibility for energy-related tax credits, particularly considering the OBCCA's modifications to clean energy incentives. Projects must meet specific criteria - such as physical work of a significant nature - to be considered as having begun construction. This determination affects whether a project qualifies under pre-OBCCA or post-OBCCA credit regimes, which may differ in value, availability, or restrictions.

We do not anticipate material impacts to our pre-OBCCA in-service clean energy generation facilities as a result of the OBCCA.

Income Tax Expense (Benefit)

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

	2025	2024
Current income tax expense (benefit) (Accounts 409.1 and 409.2)	\$ 1,583	\$ 779
Deferred income tax (benefit) (Accounts 410.1 and 411.1)	(4,353)	(1,511)
Total income tax expense (benefit)	<u>\$ (2,770)</u>	<u>\$ (732)</u>

Effective Tax Rates

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

	2025		2024	
	(dollars in thousands)			
Income before income taxes	\$ 13,942		\$ 23,053	
U.S. Federal statutory rate	2,928	21.0%	4,878	21.0%
State and local income taxes, net of feder income tax effect ^(a)	881	6.3%	1,033	4.5%
<u>Tax credits</u>				
Energy-related tax credits, net of transferability discount ^(b)	(5,182)	(37.2)%	(4,950)	(21.3)%
Other	(233)	(1.7)%	(366)	(1.6)%
<u>Non-taxable or Non-deductible Items</u>	64	0.5%	48	0.2%
<u>Changes in Unrecognized Tax Benefits</u>	29	0.2%	165	0.7%
<u>Regulatory</u>				
Amortization of excess deferred income taxes ^(c)	(1,380)	(9.9)%	(1,378)	(5.9)%
Other	9	0.1%	6	---
Other	114	0.8%	(168)	(0.7)%
Effective tax rate	<u>\$ (2,770)</u>	<u>(19.9)%</u>	<u>\$ (732)</u>	<u>(3.2)%</u>

- (a) State taxes in Colorado made up the majority (greater than 50%) for the tax effect in this category.
 (b) Tax credits are the result of production tax credits related to the Peak View Wind Farm.
 (c) Primarily a result of the Tax Cuts and Jobs Act (TCJA).

Income Taxes Paid

Income taxes (paid) received at December 31 were as follows (in thousands):

	2025		2024	
Federal:				
Direct payments (net of refunds)	\$ 4,233		\$ 3,688	
Transferred Renewable Credits (net of discount)	(5,263)		(4,899)	
Total Federal	<u>\$ (1,030)</u>		<u>\$ (1,211)</u>	
State:				
Colorado	\$ 770		\$ 1,762	
Other	---		---	
Total State	<u>\$ 770</u>		<u>\$ 1,762</u>	
Total income taxes (paid) received	<u>\$ (260)</u>		<u>\$ 551</u>	

Our Parent, BHC, files a consolidated federal and state income tax return. We have a tax sharing agreement with BHC for the allocation of consolidated tax liabilities and benefits. Income taxes paid are payments to or from BHC and represent amounts we would incur as a separate C-corporation.

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):

	2025		2024	
Deferred tax assets:				
Accelerated depreciation and other plant-related differences	\$ 3,910		\$ 3,652	
Regulatory liabilities	9,159		9,538	
State tax credits	6,024		6,081	
Federal NOL	6,131		6,523	
State NOL	124		479	
State deferred income taxes	3,175		4,075	
Credit carryovers	39,739		39,759	
Other	2,519		6,580	
Total deferred tax assets (Account 190)	<u>70,781</u>		<u>76,687</u>	
Deferred tax liabilities:				
Accelerated depreciation and other plant related differences	(162,227)		(162,050)	
State deferred income taxes	(34,484)		(36,001)	
Deferred energy costs	(173)		127	
Other	3,944		(3,532)	
Total deferred tax liabilities (Accounts 282 and 283)	<u>(192,940)</u>		<u>(201,456)</u>	
Net deferred tax assets (liabilities)	<u>\$ (122,159)</u>		<u>\$ (124,769)</u>	

Net Operating Loss and Tax Credit Carryforwards

At December 31, 2025 we have federal net operating loss (NOL) carryforwards and state tax credit carryforwards that will expire at various dates as follows (in thousands):

	Amounts	Expiration Dates
Federal NOL carryforward	\$ 29,195	No expiration
State NOL Carryforward	\$ 2,824	2041 to 2043
State investment tax credit carryforward	\$ 5,844	2030 to 2038
State research and development credit carryforward	\$ 180	No expiration

Unrecognized Tax Benefits

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 our continuing practice to recognize interest and penalties related to income tax matters in Other interest expense. During the years ended December 31, 2025 and 2024, we recognized no interest expense associated with income taxes.

(10) LEASES**Operating Leases**

We have communication tower site, land and operation center facility leases with third parties. Our leases have remaining terms ranging from 1 year to 10 years. Most of our operating leases do not contain a readily determinable discount rate. Therefore, the present value of future operating lease payments is generally calculated using our borrowing rate at lease inception. Our operating leases were not material to the Financial Statements.

Capital Leases

We have a 20-year PPA with Black Hills Colorado IPP, an affiliate, expiring on December 31, 2031. Under the PPA, Black Hills Colorado IPP provides 200 MW of power and capacity to Colorado Electric from Black Hills Colorado IPP's 50.1% owned 200 MW gas fired electric generation plants in Pueblo, Colorado. The PPA is a tolling agreement under which we will provide fuel to Black Hills Colorado IPP at no cost and purchase 100% of the output at a specified charge per unit. Affiliate Black Hills Electric Generation is responsible for the operation and maintenance of the generation plants under a separate Operating & Maintenance Services Agreement with Black Hills Colorado IPP.

The output from the power plants and the related capacity payments under the 20-year PPA are accounted for as a capital lease. The plant reverts to Black Hills Colorado IPP at the end of the 20-year lease term and the lease has no guaranteed residual value. The property, plant and equipment recorded under this lease is amortized over the 20-year term of the PPA. The present value of future capital lease payments was calculated using the Black Hills Colorado IPP's internal rate of return at lease inception.

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

	Income Statement Location		2025		2024	
Capital lease	Operating Expenses (401)	\$ 31,428	\$ 31,428	\$ 33,177	\$ 33,177	
Total lease cost		<u>\$ 31,428</u>	<u>\$ 31,428</u>	<u>\$ 33,177</u>	<u>\$ 33,177</u>	

Supplemental balance sheet information related to our capital lease was as follows (in thousands):

	Balance Sheet Location		As of December 31, 2025		As of December 31, 2024	
Assets:						
Capital lease	Utility Plant (101-106,114)	\$ 261,441	\$ 261,441	\$ 261,441	\$ 261,441	
Capital lease	(Less) Accum. Prov. For Depr. Amort. Depl. (108, 110, 111,115)	(183,009)	(183,009)	(169,937)	(169,937)	
		<u>\$ 78,432</u>	<u>\$ 78,432</u>	<u>\$ 91,504</u>	<u>\$ 91,504</u>	
Liabilities:						
Current:						
Capital lease	Obligations Under Capital Leases - Current (243)	\$ 17,714	\$ 17,714	\$ 15,663	\$ 15,663	
Noncurrent:						
Capital lease	Obligations Under Capital Leases - Noncurrent (227)	130,831	130,831	148,702	148,702	
		<u>\$ 148,545</u>	<u>\$ 148,545</u>	<u>\$ 164,365</u>	<u>\$ 164,365</u>	

Supplemental cash flow information related to our capital lease was as follows (in thousands):

	2025	2024
Cash paid for amounts included in the measurement of capital lease liability:		
Operating cash flows from capital lease	\$ 31,428	\$ 33,177
	As of December 31, 2025	As of December 31, 2024
Weighted average remaining lease term (years):		
Capital lease	6 years	7 years
Weighted average discount rate:		
Capital lease	7.3%	7.3%

Scheduled maturities of our capital lease liability for future years were as follows (in thousands):

	Capital Lease	
2026	\$	35,088
2027		35,088
2028		35,088
2029		35,088
2030		35,088
Thereafter		35,088
Total lease payments	\$	210,528
Less imputed interest		(61,983)
Present value of capital lease liability	\$	148,545

(11) RELATED-PARTY TRANSACTIONS

Dividends to Parent

For the years ended December 31, 2025 and 2024, we paid net dividends of \$18.0 million and \$1.3 million, respectively, to our Parent.

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 Secured Overnight Financing Rate (SOFR) plus 1.125%. The cost of borrowing under the Utility Money Pool was 4.81% at December 31, 2025.

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

	2025	2024
Money pool notes receivable - Notes Receivable from Associated Companies (145)	\$ 30,230	\$ 11,571
Money pool interest receivable - Notes Receivable from Associated Companies (145)	119	61

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

	2025	2024
Money pool interest income - Interest and Dividend Income (419)	\$ 1,484	\$ 534
Money pool interest expense - Interest on Debt to Assoc. Companies (430)	406	500

Notes payable to Parent

Notes payable to Parent represent the Company's assigned debt from its Parent in support of their capital and accrue interest at a rate that reflects the weighted-average rate of the assigned debt instruments.

Notes payable to Parent as of December 31 (in thousands):

	2025	2024
Notes payable to Parent - Notes Payable to Associated Companies (233)	\$ 497,440	\$ 470,440
Notes payable to Parent interest payable - Notes Payable to Associated Companies (233)	1,918	1,808

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

	2025	2024
Notes payable to Parent interest expense - Interest on Debt to Assoc. Companies (430)	\$ 22,411	\$ 20,744

Interest expense allocation from Parent

BHC provides daily liquidity and cash management on behalf of all its subsidiaries. For the years ended December 31, 2025, and 2024, we were allocated \$3.4 million and \$4.4 million, respectively, of interest expense from BHC.

Tax Sharing Agreement

Our Parent, BHC, files consolidated federal and state income tax returns. We have a tax sharing agreement with BHC for the allocation of consolidated tax liabilities and benefits. Income taxes recorded represent amounts we would incur as a separate C-Corporation. During the year ended December 31, 2025, we received \$0.3 million from BHC for our tax sharing agreement. During the year ended December 31, 2024, we paid \$0.6 million, respectively, to BHC due to our tax sharing agreement. As of December 31, 2025, we had an income tax payable to BHC of \$1.2 million related to our tax sharing agreement. As of December 31, 2024, we did not have an income tax receivable or payable from BHC related to our tax sharing agreement.

Other Related-Party Agreements

- A shared services agreement with Black Hills Colorado IPP. Black Hills Colorado IPP assets are located at the Pueblo Airport Generating Station ("PAGS") site, with generation assets owned by us. We have entered into a facility agreement with Black Hills Colorado IPP that allows shared utilization of certain utility assets for a facility fee. The facility fee charge is based on the cost of the associated assets, along with the related operating expenses, and allocated between us and Black Hills Colorado IPP based on generation asset nameplate rating owned by each party at the PAGS site.
- A Power Purchase Agreement (PPA) with Black Hills Colorado IPP, which commenced January 1, 2012, and expires in 2031, provides 200 MW of energy and capacity to us from Black Hills Colorado IPP's combined-cycle turbines. This PPA is accounted for as a capital lease (see Note 10 for additional details).
- A renewable energy PPA with Black Hills Electric Generation (BHEG) expiring on October 16, 2037, which provides up to 14.5 MW of wind energy from BHEG's owned interest in the Busch Ranch I wind farm (see Note 6 for additional details).
- A renewable energy PPA with Black Hills Electric Generation (BHEG) expiring in November 2044, which provides 60 MW of wind energy from the Busch Ranch II wind farm.
- We have a service agreement with BHSC, whereby BHSC charges us, at cost, for various direct and indirect services provided to us. Pursuant to the BHSC Cost Allocation Manual, indirect service cost allocations are determined in accordance with the Public Utility Holding Company Act of 2005.

Costs under these power purchase contracts for the years ended December 31 were as follows (in thousands):

	2025	2024
Operating Revenues:		
Revenue from Black Hills Colorado IPP under shared services agreement	\$ 1,280	\$ 1,219
Operating Expenses:		
Capacity charges from Black Hills Colorado IPP	\$ 31,428	\$ 33,177
Energy purchases from Black Hills Colorado IPP	25,225	23,357
Purchase of renewable wind energy from BHEG - Busch Ranch I	1,784	2,113
Purchase of renewable wind energy from BHEG - Busch Ranch II	3,007	3,733
Direct services and fees from Black Hills Service Company	11,093	12,136
Indirect services and fees from Black Hills Service Company	35,530	33,436

(12) SUPPLEMENTAL CASH FLOW INFORMATION

Years ended December 31, (in thousands)

	2025	2024
Cash (paid) during the period for:		
Interest (net of amounts capitalized)	\$ (26,172)	\$ (24,104)
Income taxes	261	(551)
Non-cash investing activities:		
Accrued property, plant and equipment purchases at December 31	\$ 6,883	\$ 6,650

(13) ASSET RETIREMENT OBLIGATION

We have identified legal retirement obligations related to removal of fuel tanks, transformers containing polychlorinated biphenyls, an evaporation pond, our Busch Ranch I and Peak View wind turbines and removal of asbestos. We periodically review and update estimated costs related to these AROs. The actual cost may vary from estimates because of regulatory requirements, changes in technology and increased costs of labor, materials and equipment.

The following table presents our Asset Retirement Obligations (Account Z30) which are included on the Balance Sheets (in thousands):

					Balance at December 31, 2025
Balance at December 31, 2024	11,474	\$	-	\$	11,971
Liabilities Incurred				497	
Liabilities Settled					
Accretion					
Revisions					
Balance at December 31, 2023	10,998	\$	-	\$	11,474
Liabilities Incurred				318	
Liabilities Settled					
Accretion					
Revisions				158	

We also have legally required AROs related to certain assets within our electric transmission and distribution systems. These retirement obligations are pursuant to an easement or franchise agreement and are only required if we discontinue our utility service under such easement or franchise agreement. Accordingly, it is not feasible to estimate a time period when these obligations could be settled and therefore, a liability for the cost of these obligations cannot be measured at this time.

(14) PENDING MERGER BETWEEN BHC AND NORTHWESTERN

On August 18, 2025, BHC entered into an agreement and plan of merger, with NorthWestern Energy Group, Inc. ("NorthWestern") and River Merger Sub Inc. ("Merger Sub"). The merger agreement provides for Merger Sub to merge with and into NorthWestern, with NorthWestern continuing as the surviving entity and a direct wholly owned subsidiary of BHC, which will assume a new corporate name as the resulting parent company of the combined corporate group. At the effective time of the Merger (the "Effective Time"), each share of common stock of NorthWestern, par value \$0.01 per share, issued and outstanding as of immediately prior to the Effective Time will be converted into the right to receive 0.98 validly issued, fully paid and non-assessable shares of our common stock, par value \$1.00 per share (or cash-in-lieu of fractional shares thereof), in each case upon and subject to the terms and conditions of the merger agreement.

The merger agreement, which was unanimously approved by both the board of directors of BHC and the board of directors of NorthWestern on August 18, 2025, provides for a tax-free, all-stock business combination of BHC and NorthWestern upon the terms and subject to the conditions set forth therein. Such conditions include, among other things, clearance under the Hart-Scott-Rodino Act, consent of the Federal Communications Commission, approval from each company's shareholders, and regulatory approvals, including approval from the South Dakota Public Utilities Commission, Nebraska Public Service Commission and Montana Public Service Commission, as well as the United States Department of Energy's Federal Energy Regulatory Commission.

At closing, the combined company will be named Bright Horizon Energy Corporation.

We anticipate the transaction closing in the second half of 2026, subject to the satisfaction of certain closing conditions including receipt of shareholder approvals and certain regulatory approvals as mentioned above.

(15) SUBSEQUENT EVENTS

We have evaluated subsequent events through April 2, 2026, which is the date the financial statements were available to be issued. Except as described in Notes 2, 3, 9, and 14, there have been no events subsequent to December 31, 2025, which would require recognition in the financial statements or disclosures.

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 Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year									
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income									
3	Preceding Quarter/Year to Date Changes in Fair Value									
4	Total (lines 2 and 3)								23,785,085	23,785,085
5	Balance of Account 219 at End of Preceding Quarter/Year									
6	Balance of Account 219 at Beginning of Current Year									
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income									
8	Current Quarter/Year to Date Changes in Fair Value									
9	Total (lines 7 and 8)								16,713,041	16,713,041
10	Balance of Account 219 at End of Current Quarter/Year									

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)	1,317,200,899	1,287,770,797		29,430,102			
4	Property Under Capital Leases	262,364,147	922,743			261,441,404		
5	Plant Purchased or Sold							
6	Completed Construction not Classified	48,705,301	48,705,301					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	1,628,270,347	1,337,398,841		29,430,102	261,441,404		
9	Leased to Others							
10	Held for Future Use	3,251,715	3,251,715					
11	Construction Work in Progress	35,670,621	35,670,621					
12	Acquisition Adjustments	234,762,278	234,762,278					
13	Total Utility Plant (8 thru 12)	1,901,954,961	1,611,083,455		29,430,102	261,441,404		
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	622,372,392	428,605,291		10,758,119	183,008,982		
15	Net Utility Plant (13 less 14)	1,279,582,569	1,182,478,164		18,671,983	78,432,422		
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	620,811,181	427,044,080		10,758,119	183,008,982		
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	1,561,211	1,561,211					
22	Total in Service (18 thru 21)	622,372,392	428,605,291		10,758,119	183,008,982		
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							
33	Total Accum Prov (equals 14) (22,26,30,31,32)	622,372,392	428,605,291		10,758,119	183,008,982		

Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
(1) An Original
(2) A Resubmission

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: UtilityPlantInServicePropertyUnderCapitalLeases

Amount represents operating leases in accordance with ASC Topic 842 and FERC Docket No. AI19-1-000.

(b) Concept: UtilityPlantInServiceClassified

Amounts in column (e) represent allocated property and related accumulated provision for depreciation from Black Hills Service Company.

(c) Concept: UtilityPlantInServicePropertyUnderCapitalLeases

Amounts in column (f) represent capital lease asset and related accumulated depreciation associated with 20-year PPA with Black Hills Colorado IPP which is accounted for as a capital lease.

Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
(1) An Original
(2) A Resubmission

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ 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)					

Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
(1) An Original
(2) A Resubmission

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ 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	200,900					200,900
3	(302) Franchise and Consents						
4	(303) Miscellaneous Intangible Plant	329,000					329,000
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	529,900					529,900
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	254,248		133,718		(70,532)	49,998
9	(311) Structures and Improvements						
10	(312) Boiler Plant Equipment						
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units						
13	(315) Accessory Electric Equipment						
13.1	(315.1) Computer Hardware						
13.2	(315.2) Computer Software						
13.3	(315.3) Communication Equipment						
14	(316) Misc. Power Plant Equipment						
15	(317) Asset Retirement Costs for Steam Production						
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	254,248		133,718		(70,532)	49,998
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						
22.1	(324.1) Computer Hardware						
22.2	(324.2) Computer Software						
22.3	(324.3) Communication 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						
31.1	(334.1) Computer Hardware						
31.2	(334.2) Computer Software						
31.3	(334.3) Communication 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)						

35.1	D. Solar Production Plant						
35.2	(338.1) Land and Land Rights						
35.3	(338.2) Structures and Improvements						
35.5	(338.4) Solar Panels						
35.6	(338.5) Collector System						
35.7	(338.6) Generator Step-up Transformers (GSU)						
35.8	(338.7) Inverters						
35.9	(338.8) Other Accessory Electrical Equipment						
35.10	(338.9) Computer Hardware						
35.11	(338.10) Computer Software						
35.12	(338.11) Communication Equipment						
35.13	(338.12) Miscellaneous Power Plant Equipment						
35.14	(338.13) Asset Retirement Costs for Solar Production						
35.15	TOTAL Solar Production Plant (Enter Total of lines 35.2 thru 35.14)						
35.16	E. Wind Production Plant						
35.17	(338.20) Land and Land Rights						
35.18	(338.21) Structures and Improvements					16,512,675	16,512,675
35.20	(338.23) Wind Turbines					68,971,675	68,971,675
35.21	(338.24) Wind Towers and Fixtures					22,992,966	22,992,966
35.23	(338.26) Collector System					8,567,264	8,567,264
35.24	(338.27) Generator Step-up Transformers (GSU)						
35.25	(338.28) Inverters					69,908	69,908
35.26	(338.29) Other Accessory Electrical Equipment						
35.27	(338.30) Computer Hardware						
35.28	(338.31) Computer Software						
35.29	(338.32) Communication Equipment		143,676			81,804	225,480
35.30	(338.33) Miscellaneous Power Plant Equipment						
35.31	(338.34) Asset Retirement Costs for Wind Production					4,326,815	4,326,815
35.32	TOTAL Wind Production Plant (Enter Total of lines 35.17 thru 35.31)		143,676			121,523,107	121,666,783
35.33	F. Other Renewable Production Plant						
35.34	(339.1) Land and Land Rights						
35.35	(339.2) Structures and Improvements						
35.36	(339.3) Fuel Holders						
35.37	(339.4) Boilers						
35.39	(339.6) Generators						
35.41	(339.8) Other Accessory Electrical Equipment						
35.42	(339.9) Computer Hardware						
35.43	(339.10) Computer Software						
35.44	(339.11) Communication Equipment						
35.45	(339.12) Miscellaneous Power Plant Equipment						
35.46	(339.13) Asset Retirement Costs for Other Renewable Production						
35.47	TOTAL Other Renewable Production Plant (Enter Total of lines 35.34 thru 35.46)						
36	G. Other Production Plant						
37	(340) Land and Land Rights	6,436,743					6,436,743
38	(341) Structures and Improvements	16,859,547	117,379		(41,588)		16,935,338
39	(342) Fuel Holders, Products, and Accessories	9,020,423	277,665	270,519	165,617		9,193,186
40	(343) Prime Movers	2,273,005			(415,796)		1,857,209
41	(344) Generators	375,838,430	4,345,006	984,874	(1,228,006)	(117,044,579)	260,925,977
42	(345) Accessory Electric Equipment	18,867,818	67,275	84,270	(115,403)	(331,760)	18,403,660
42.1	(345.1) Computer Hardware		43,648			365,264	408,912
42.2	(345.2) Computer Software						
42.3	(345.3) Communication Equipment					604,861	604,861
43	(346) Misc. Power Plant Equipment	2,802,388				(128,352)	2,674,036
44	(347) Asset Retirement Costs for Other Production	7,184,936				(4,326,815)	2,858,121
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	439,283,290	4,850,973	1,339,663	(1,635,176)	(120,861,381)	320,298,043
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, 35.15, 35.32, 35.47, and 45)	439,537,538	4,994,649	1,473,381	(1,635,176)	591,194	442,014,824
47	3. Transmission Plant						

48	(350) Land and Land Rights	7,828,019	3,980				7,831,999
48.2	(351.1) Computer Hardware						
48.3	(351.2) Computer Software						
48.4	(351.3) Communication Equipment		3,176,928	1,391,095	(1,324,389)	5,016,988	5,478,432
49	(352) Structures and Improvements	12,257,762	9,859				12,267,621
50	(353) Station Equipment	131,880,786	307,926	369,076	66,133	(4,969,283)	126,916,486
51	(354) Towers and Fixtures						
52	(355) Poles and Fixtures	111,918,547	7,147,597	3,614,373	603,235		116,055,006
53	(356) Overhead Conductors and Devices	69,553,782	1,396,235	1,253,165	580,098	(21,173)	70,255,777
54	(357) Underground Conduit						
55	(358) Underground Conductors and Devices						
56	(359) Roads and Trails						
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	333,438,896	12,042,525	6,627,709	(74,923)	26,532	338,805,321
59	4. Distribution Plant						
60	(360) Land and Land Rights	1,650,603	(543)			(242,634)	1,407,426
61	(361) Structures and Improvements	4,124,819					4,124,819
62	(362) Station Equipment	68,250,777	2,898,314	88,330	28,271	(1,216,432)	69,872,600
63.1	(363.1) Computer Hardware						
63.2	(363.2) Computer Software						
63.3	(363.3) Communication Equipment		363,817	142,607	(33,518)	1,348,439	1,536,131
64	(364) Poles, Towers, and Fixtures	124,774,851	770,801	283,577	870,996	22,051	126,155,122
65	(365) Overhead Conductors and Devices	63,022,816	1,700,325	81,347	129,376	82,735	64,853,905
66	(366) Underground Conduit	31,367,241	(614,507)	(3,769)	691		30,757,194
67	(367) Underground Conductors and Devices	38,665,720	4,448,139	85,025	640,908	29,080	43,698,822
68	(368) Line Transformers	84,168,646	8,027,801	371,667	55,587	(23,239)	91,857,128
69	(369) Services	28,782,129	2,151,238	66,325	(18,729)		30,848,313
70	(370) Meters	18,535,980	824,363	1,546,477		1,233,572	19,047,438
71	(371) Installations on Customer Premises	3,066,772	159,373	46,204	9,982		3,189,923
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	12,399,830	1,029,772	52,087	15,570		13,393,085
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	478,810,184	21,758,893	2,759,877	1,699,134	1,233,572	500,741,906
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)						
84.1	6. ENERGY STORAGE PLANT						
84.2	(387.1) Land and Land Rights						
84.3	(387.2) Structures and Improvements						
84.4	(387.3) Energy Storage Equipment						
84.6	(387.5) Collector System						
84.7	(387.6) Generator Step-up Transformers (GSU)						
84.8	(387.7) Inverters						
84.9	(387.8) Computer Hardware						
84.10	(387.9) Computer Software						
84.11	(387.10) Communication Equipment						
84.12	(387.11) Miscellaneous Energy Storage Equipment						
84.13	(387.12) Asset Retirement Costs for Energy Storage						
84.14	TOTAL Energy Storage Plant (Total lines 84.2 thru 84.13)						
85	7. General Plant						
86	(389) Land and Land Rights	283,939					283,939

87	(390) Structures and Improvements	9,874,844	725,991	111,988	18,068		10,506,915
88	(391) Office Furniture and Equipment	3,228,719	154,434	165,350		(1,705,215)	1,512,588
89	(392) Transportation Equipment	25,230,735	2,761,679	1,106,853			26,885,561
90	(393) Stores Equipment	24,905	24,391				49,296
91	(394) Tools, Shop and Garage Equipment	3,873,018	7,075	2,384			3,877,709
92	(395) Laboratory Equipment	1,390,161	13,300	6,119			1,397,342
93	(396) Power Operated Equipment	5,639,339	243,699	326,596		(2,257)	5,554,185
94	(397.1) Computer Hardware		242,481	177,814			536,292
94.1	(397.2) Computer Software						
94.2	(397.3) Communication Equipment	1,067,691	2,056,437	2,183			483,665
95	(398) Miscellaneous Equipment	85,443	18,924	2,612			101,755
96	SUBTOTAL (Enter Total of lines 86 thru 95)	50,698,794	6,248,411	1,901,899		15,811	(685,258)
97	(399) Other Tangible Property	939,680				(16,937)	922,743
98	(399.1) Asset Retirement Costs for General Plant	11,288					11,288
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	51,649,762	6,248,411	1,901,899		(1,126)	(685,258)
100	TOTAL (Accounts 101 and 106)	1,303,966,280	45,044,478	12,762,866		(12,091)	1,166,040
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)	1,303,966,280	45,044,478	12,762,866		(12,091)	1,166,040

Name of Respondent:
Black Hills Colorado Electric, LLC

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12/31/2025

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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)
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47	TOTAL					

Name of Respondent:
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12/31/2025

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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	3000 Lake Ave Pueblo CO - 91004 Parcel 1 & 2	03/01/2017		339,973
3	Greenhorn Street Substation	03/01/2021		2,753,405
4				
21	Other Property:			
22	Osage Plant - Water/Well Assets	10/01/2014		158,337
47	TOTAL			3,251,715

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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	10086235-Fowler Sub XFMR Replacement	1,729,353
2	10086230-Canon Plant Substation XFMR Add	1,780,815
3	DISTRIBUTION PLANT LESS THAN \$1,000,000 EACH	8,668,598
4	GENERAL PLANT-ELECTRIC LESS THAN \$1,000,000 EACH	3,167,446
5	10088248-PAGS Unit 1 Hot Section Overhaul	2,599,898
6	10084366-COE PAGS LMS100 Power Turbine	7,392,347
7	OTHER GENERATION -PLANT LESS THAN \$1,000,000 EACH	755,647
8	10079179-West Station-Portland 115	8,626,443
9	MISC TRANSMISSION LESS THAN \$1,000,000 EACH	950,074
43	Total	35,670,621

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	402,359,365	402,359,365		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	36,457,148	36,457,148		
4	(403.1) Depreciation Expense for Asset Retirement Costs	315,683	315,683		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,397,234	1,397,234		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Right of Use	518,808	518,808		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	38,688,873	38,688,873		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(10,977,494)	(10,977,494)		
13	Cost of Removal	(3,889,035)	(3,889,035)		
14	Salvage (Credit)	665,878	665,878		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(14,200,651)	(14,200,651)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Asset Retirement Obligation and Pending Retirements	196,493	196,493		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	427,044,080	427,044,080		
Section B. Balances at End of Year According to Functional Classification					
20	Steam Production	40,269	40,269		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
23.1	Solar Production				
23.2	Wind Production	48,481,464	48,481,464		
23.3	Other Renewable Production				
24	Other Production	118,192,101	118,192,101		
25	Transmission	53,786,921	53,786,921		
26	Distribution	182,438,180	182,438,180		
27	Regional Transmission and Market Operation				
27.1	Energy Storage				
28	General	24,105,145	24,105,145		
29	TOTAL (Enter Total of lines 20 thru 28)	427,044,080	427,044,080		

(a) Concept: AccumulatedDepreciationOtherProduction

Includes an ARO amount of \$1,350,783

(b) Concept: AccumulatedDepreciationGeneral

Includes an ARO amount of \$10,824

Name of Respondent:
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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								
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42	Total Cost of Account 123.1 \$		Total					

MATERIALS AND SUPPLIES

- 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.
- 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)	446,621	408,586	Production
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	6,145,367	8,496,599	Transmission & Distribution
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	5,487,217	5,313,660	Production
8	Transmission Plant (Estimated)	525	896	Transmission
9	Distribution Plant (Estimated)	15,684	26,770	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
10.1	Energy Storage Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	6,275	16,752	General
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	11,655,068	13,854,677	
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)	713,582	906,025	
17				
18				
19				
20	TOTAL Materials and Supplies	12,815,271	15,169,288	

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FOOTNOTE DATA

[\(a\)](#) Concept: PlantMaterialsAndOperatingSuppliesOther

This amount represents allocated O&M capitalized to General material and supplies.

Name of Respondent:
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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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
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20	TOTAL					

Name of Respondent:
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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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
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49	TOTAL					

Name of Respondent:
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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	G69-2 Restudy	175,170	561.7	175,170	561.7
3	TSA-11 NITS-60M	11,947	561.6	12,347	561.6
4	NITS-432MW Greenhorn	52,680	561.6	329	561.6
5	12-Greenhorn-311		561.6	9,294	561.6
20	Total	239,797		197,140	
21	Generation Studies				
39	Total				
40	Grand Total	239,797		197,140	

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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		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Asset Retirement Obligation	348,314	5,809			354,123
2	Pension Plan	10,686,121	336,067	Various	302,907	10,719,281
3	Energy Cost Adjustment	0	144,601,818	Various	144,601,818	0
4	Energy Efficiency Program / Demand Side Management	2,177,626	8,887,247	Various	10,314,158	750,715
5	Decommissioning Costs (Jan 2014 - Dec 2018)	2,406,687	136,298		67,469	2,475,516
6	Deferred Taxes related to Retiree Healthcare Plan Regulatory Liability	537,098	13,805	Various	1,262	549,641
7	^(a) Electric Vehicle Transportation Electrification Program	172,695	670,532	Various	692,472	150,755
8	Deferred Taxes on AFUDC	209,321	13,680	Various	27,371	195,630
9	^(a) Electric Resource Plan	2,476,224	1,652,741	Various	2,105,795	2,023,170
10	^(a) Net Operating Loss Deficient Deferred Income Tax	29,701,087	1,253,970	Various	1,581,815	29,373,242
11	^(a) State Deficient Deferred Income Tax	8,301,618	196,864	Various	507,614	7,990,868
12	^(a) Cost of Removal Deficient Deferred Income Tax	1,595,020	18,688	Various	18,714	1,594,994
13	Black Hills Energy Assistance Program	0	5,669,902	Various	5,669,902	0
14	Rate Case Expenses	0	1,133,069	Various	193,499	939,570
44	TOTAL	58,611,811	164,590,490		166,084,796	57,117,505

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FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

The description in column (a) of this regulatory asset was updated from "Renewable RFP" in the prior year.

(b) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Began in January 2020.

(c) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

In prior year, 'Net Operating Loss Deficient Deferred Income Tax', 'State Deficient Deferred Income Tax', and Cost of Removal Deficient Deferred Income Tax' were combined as 'Deficient Deferred Income Taxes'.

(d) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

In prior year, 'Net Operating Loss Deficient Deferred Income Tax', 'State Deficient Deferred Income Tax', and Cost of Removal Deficient Deferred Income Tax' were combined as 'Deficient Deferred Income Taxes'.

(e) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

In prior year, 'Net Operating Loss Deficient Deferred Income Tax', 'State Deficient Deferred Income Tax', and Cost of Removal Deficient Deferred Income Tax' were combined as 'Deficient Deferred Income Taxes'.

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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	Deferred Rate Case Expenses	502,621	144,453		647,074	0
2	Deferred Distribution System Planning Expenses	390,532	39,721		280,871	149,382
3	Deferred Assets Other	0	82,412			82,412
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	893,153				231,794

Name of Respondent:
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12/31/2025

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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	Accelerated depreciation and other plant-related differences	3,652,000	3,910,417
3	Credit Carryovers	40,095,029	40,069,823
4	Federal NOL carryforward	6,523,328	6,130,931
5	Regulatory Assets	9,537,952	9,158,923
6	State NOL carryforward	478,613	124,248
7	State deferred income taxes	4,074,753	3,174,603
8	State tax credits	6,081,213	6,023,749
9	Valuation allowance	(335,926)	(330,807)
7	Other	6,579,863	2,518,637
8	TOTAL Electric (Enter Total of lines 2 thru 7)	76,686,825	70,780,524
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	76,686,825	70,780,524
Notes			

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End of: 2025/ 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							
6	Total	50,000,000								
7	Preferred Stock (Account 204)									
9	Total									

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	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	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	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	418,981,943
15.1	Dividend from Parent	8,000,000
15	Increases (Decreases) Due to Miscellaneous Paid-In Capital	8,000,000
16	Ending Balance Amount	426,981,943
17	Other Paid in Capital	
18	Beginning Balance Amount	
19	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	426,981,943

Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
(1) An Original
(2) A Resubmission

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ 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	
22	TOTAL	

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12/31/2025

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End of: 2025/ 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 from Associated Companies, and 224, Other 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 (b) include the related account number.
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received, 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 (b) include the related account number.
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, show for each company: (a) principal advanced 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 of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
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 (m). Explain in a footnote any difference 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)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1	Bonds (Account 221)												
2													
3													
4													
5	Subtotal												
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												

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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 filed, 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)	16,713,041
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5		
9	Deductions Recorded on Books Not Deducted for Return	
10	Nondeductible and deferred taxes-principally federal income	(2,770,563)
11	Benefits Addback	36,657
12	Fines & Penalties	1,266
13	Club Dues	40,943
14	Lobbying	95,049
15	Entertainment	10,025
16	Operating Lease Assets	75,240
17	ARO FASB 143 Asset	806,594
18	Public Utilities Commission Fees	(558,906)
19	Meals	199,314
20	Bad Debt Reserve	125,378
21	Deferred Regulatory Asset	15,678,042
14	Income Recorded on Books Not Included in Return	
15	Operating Lease Liability	(75,878)
16	Prepaid Expenses	(497,246)
17	Benefits	(40,488)
18	Depreciation	(3,181,842)
19	Net Operating Loss Carryover	(19,126,385)
19	Deductions on Return Not Charged Against Book Income	
20		
27	Federal Tax Net Income	7,530,242
28	Show Computation of Tax:	
29	Tax Amount	1,511,771
30	Intercompany Payment	926,668

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 during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (g) and (h). The balancing of this 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, (b) amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d).
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 by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)	
1	Federal Income Tax	Income Tax	Federal	2025	172,360		277,150	(1,234,621)		1,684,131		641,482				(364,332)
2	State Income Tax	Income Tax	CO	2025	37,778		1,305,422	974,092		369,108		1,385,272				(79,850)
3	Property Tax	Property Tax	CO	2025	11,473,076		11,329,101	11,427,129		11,375,048		11,018,404				310,696
4	Sales and Use Tax	Sales And Use Tax	CO	2025	17,180		57,706	48,676		26,210		(54,181)				111,887
5	Federal Insurance Contribution Tax	Federal Insurance Tax	Federal	2025	92,165		2,879,340	2,871,505		100,000		1,705,365				1,173,975
6	Federal Unemployment Tax	Unemployment Tax	Federal	2025	8		8,434	8,421		21		13,619				(5,185)
7	State Unemployment Tax	Unemployment Tax	CO	2025	140		61,080	61,155		65		70,935				(9,855)
40	TOTAL				11,792,707	0	15,918,233	14,156,357	0	13,554,583	0	14,780,896	0	0	0	1,137,336

FOOTNOTE DATA

(a) Concept: TaxesAccruedPrepaidAndCharged

Note: Below is the income tax as adjusted with the income tax effect of non-operating interest expense

Taxes as booked on FERC:	
Income Taxes- 409.1	2,026,754
Net Interest Expense - Total	27,497,901
Net Interest Expense Already Accounted for in Income Tax	(5,590,810)
Non-Operating Net Interest Expense Needing an Income Tax Adj	21,907,091
Remove Income Tax Effect of Non-Operating Interest Expense	(5,361,980)
Income Taxes- 409.1 As Adjusted	7,388,734

(b) Concept: TaxesAccruedPrepaidAndCharged

Note: Below is the income tax as adjusted with the income tax effect of non-operating interest expense

Taxes as booked on FERC:	
Income Taxes- 409.1	2,026,754
Net Interest Expense - Total	27,497,901
Net Interest Expense Already Accounted for in Income Tax	(5,590,810)
Non-Operating Net Interest Expense Needing an Income Tax Adj	21,907,091
Remove Income Tax Effect of Non-Operating Interest Expense	(5,361,980)
Income Taxes- 409.1 As Adjusted	7,388,734

Name of Respondent:
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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%	3,133,477			411.4	172,342		2,961,135		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	3,133,477				172,342		2,961,135		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
47	OTHER TOTAL									
48	GRAND TOTAL	3,133,477				172,342		2,961,135		

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12/31/2025

Year/Period of Report
End of: 2025/ 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	Black Hills Energy Assistance Program	23,912	Various	150,241	152,713	26,384
2	Contractor Retainage	99,159	Various	3,409,565	3,460,332	149,926
47	TOTAL	123,071		3,559,806	3,613,045	176,310

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 relating 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)
			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)	Debits		Credits		
							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										
5.2	Other										
8	TOTAL Electric (Enter Total of lines 3 thru 7)										
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other										
12.2	Other										
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										

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to property not subject to accelerated 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 at End of Year (k)
			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)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 282										
2	Electric	142,243,027	10,997,015	9,836,704			182.3	16,181	182.3	26,520	143,413,677
3	Gas										
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	142,243,027	10,997,015	9,836,704				16,181		26,520	143,413,677
6											
7											
8											
9	TOTAL Account 282 (Total of Lines 5 thru 8)	142,243,027	10,997,015	9,836,704				16,181		26,520	143,413,677
10	Classification of TOTAL										
11	Federal Income Tax	116,822,644	9,577,677	8,625,954			182.3	13,542	182.3	22,022	117,782,847
12	State Income Tax	25,420,383	1,419,338	1,210,750			182.3	2,639	182.3	4,498	25,630,830
13	Local Income Tax										

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				ADJUSTMENTS				Balance at End of Year (k)
			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)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	Deferred Energy Costs	(155,175)	3,958,934	3,630,907							172,852
4	Depreciation	44,148,420	(2,481,259)	(2,904,419)							44,571,580
5	Other	3,315,163	10,119,644	17,492,524		182.3	8,595	182.3	(5,244)		(4,071,556)
6	State Deferred Income Taxes	11,904,736	2,555,938	5,604,874		254.0	2,109	254.0			8,853,691
9	TOTAL Electric (Total of lines 3 thru 8)	59,213,144	14,153,257	23,823,886					10,704	(5,244)	49,526,567
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other										
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	59,213,144	14,153,257	23,823,886					10,704	(5,244)	49,526,567
20	Classification of TOTAL										
21	Federal Income Tax	43,719,750	12,144,591	20,092,124				9,246		(4,389)	35,758,582
22	State Income Tax	15,493,394	2,008,666	3,731,762				1,458		(855)	13,767,985
23	Local Income Tax										

NOTES

Name of Respondent:
Black Hills Colorado Electric, LLC

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12/31/2025

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End of: 2025/ 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	^(b) Investment Tax Credits	1,015,507	Various	55,853		959,654
2	Deferred Taxes related to Pension Plan Regulatory Asset	3,463,184	Various	89,986	81,180	3,454,378
3	^(b) Protected Property Excess Deferred Income Tax	69,848,713	Various	3,371,451	1,224,735	67,701,997
4	^(b) Non-Protected Property Excess Deferred Income Tax	22,808	Various	1,140	1,578	23,246
5	Energy Assistance Program	159,323	Various	884,922	1,129,211	403,612
6	Retiree Healthcare Program	1,657,288	Various	4,248	65,231	1,718,271
7	Renewable Energy Standard Adjustment	24,071,905	Various	108,500,171	113,781,834	29,353,568
8	Power Cost Adjustment	3,163,037	Various	9,202,272	13,976,686	7,937,451
9	Clean Energy Plan	0	Various	5,482,103	9,304,914	3,822,811
41	TOTAL	103,401,765		127,592,146	139,565,369	115,374,988

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End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Monthly amortization ending 12/31/2035.

(b) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Monthly amortization ending 12/31/2067.

(c) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Monthly amortization ending 12/31/2067.

Electric Operating Revenues

- 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.
- Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
- 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.
- 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.
- Disclose amounts of \$250,000 or greater in a footnote for accounts 451, 456, and 457.2.
- 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.)
- See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
- For Lines 2,4,5, and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
- 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	111,320,411	104,283,607	594,925	611,784	89,731	89,252
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	\$97,882,062	91,907,515	716,748	749,332	11,952	11,950
5	Large (or Ind.) (See Instr. 4)	\$37,207,648	34,813,856	338,097	351,971	55	55
6	(444) Public Street and Highway Lighting	989,561	904,401	6,239	6,189	180	175
7	(445) Other Sales to Public Authorities	11,185,852	10,486,311	98,147	101,525	292	285
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	258,585,534	242,395,690	1,754,156	1,820,801	102,210	101,717
11	(447) Sales for Resale	21,619,352	19,828,286	463,981	571,850	22	22
12	TOTAL Sales of Electricity	280,204,886	262,223,976	2,218,137	2,392,651	102,232	101,739
13	(Less) (449.1) Provision for Rate Refunds	(10)	(413)				
14	TOTAL Revenues Before Prov. for Refunds	280,204,896	262,224,389	2,218,137	2,392,651	102,232	101,739
15	Other Operating Revenues						
16	(450) Forfeited Discounts	260,628	158,451				
17	(451) Miscellaneous Service Revenues	\$557,314	719,577				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	2,049,834	1,909,504				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	\$990,188	\$2,054,850				
22	(456.1) Revenues from Transmission of Electricity of Others	2,859,777	9,074,503				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	6,717,741	13,916,885				
27	TOTAL Electric Operating Revenues	286,922,637	276,141,274				

Line12, column (b) includes \$ of unbilled revenues.
Line12, column (d) includes MWH relating to unbilled revenues

Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
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12/31/2025

Year/Period of Report
End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Commercial revenues

(b) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Industrial revenues

(c) Concept: MiscellaneousServiceRevenues

Consists of site visit and interconnection revenue

(d) Concept: OtherElectricRevenue

In June 2025, Colorado Electric received \$0.6 million in payments from NextEra Energy, Inc. to transfer electric service of NextEra subsidiaries Neptune Energy Center, LLC and Thunder Wolf Energy Center, LLC (solar and energy storage projects in Pueblo, Colorado) to Public Service Company of Colorado. Additionally, Colorado Electric received \$0.4 million in payments related to the Demand Side Management performance incentive.

(e) Concept: OtherElectricRevenue

In June 2024, Colorado Electric received \$0.8 million in payments from NextEra Energy, Inc. to transfer electric service of NextEra subsidiaries Neptune Energy Center, LLC and Thunder Wolf Energy Center, LLC (solar and energy storage projects in Pueblo, Colorado) to Public Service Company of Colorado. Additionally, Colorado Electric received \$1.2 million in payments related to the Demand Side Management performance incentive.

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12/31/2025

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End of: 2025/ 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)
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43					
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45					
46	TOTAL				

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on 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	CO900 - Residential-Electric Vehicle Time of Day	233	33,741	18	12,944	0.145
2	CO885 - Net Metering-Residential Non-Photovoltaic System	57	8,921	3	19,000	0.157
3	COM26 - Private Area Lighting Dusk to Dawn Burning	208	51,324	39	5,333	0.247
4	COPA2 - New Lamp-Customer Owns 0%-B	38	21,338	11	3,455	0.562
5	COPB2 - New Lamp-Customer Owns 25%	2	899			0.450
6	COPC1 - New Lamp-Customer Owns 50%-A	4	799			0.200
7	COPC2 - New Lamp-Customer Owns 50%-B	1	332	1	1,000	0.332
8	COPD1 - New Lamp-Customer Owns 75%-A	4	514			0.129
9	COPD2 - New Lamp-Customer Owns 75%-B	43	7,848	12	3,583	0.183
10	COPE1 - New Lamp-Customer Owns 100%-A	31	2,339	7	4,429	0.075
11	COPE2 - New Lamp-Customer Owns 100%-B	734	68,047	145	5,062	0.093
12	CO901 - Residential Adjustment	245	50,094	19	12,895	0.204
13	Renewable Energy Standard Adjustment		(1,768,392)			
14	Demand Side Management		(3,311,628)			
15	Peak View		2,162,861			
16	Excess Deferred Income Taxes		(125,212)			
17	CO860 - Residential Service	559,834	86,407,405	77,829	7,193	0.154
18	CO861 - Residential-Multi Dwelling Units	905	163,203	66	13,712	0.180
19	CO862 - Residential-Pilot Innovative Pricing	252	38,448	32	7,875	0.153
20	CO863 - Residential-Pilot Direct Load Control	279	42,434	35	7,971	0.152
21	CO865 - Residential-Other Use	6,732	631,026	1,947	3,458	0.094
22	CO864 - Residential-Medium Exempt	1,687	248,824	126	13,389	0.147
23	CO875 - Net Meeting-Residential Solar	23,321	4,228,499	9,441	2,470	0.181
41	TOTAL Billed Residential Sales	594,610	88,963,664	89,731	6,627	0.150
42	TOTAL Unbilled Rev. (See Instr. 6)	315	22,356,747			70.974
43	TOTAL	594,925	111,320,411	89,731	6,630	0.187

SALES OF ELECTRICITY BY RATE SCHEDULES

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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	CO904 - Large General Service Electric Vehicle Time of Day	1,274	508,703	5	254,800	0.399
2	CO811 - Commercial Firm	5	738	1	5,000	0.148
3	CO876 - Net Metering-NonRes less than 10 KW-Photovoltaic	466	67,586	97	4,804	0.145
4	CO877 - Net Metering-NonRes 10 to 50KW-Photovoltaic	5,011	600,530	121	41,413	0.120
5	CO878 - Net Metering-NonRes to 1400KW-Photovoltaic	21,202	2,492,342	36	588,944	0.118
6	CO879 - Net Metering-NonRes over 1400KW-Photovoltaic	6,045	470,245	4	1,511,250	0.078
7	CO906 - COE Commercial Firm	252	101,201	5	50,400	0.402
8	CO920 - Large General Service-Secondary-Time of Use	8,502	794,962	9	944,667	0.094
9	CO936 - Large Power Service-Transmission-Time of Use	432	133,406			0.309
10	CO938 - Industrial Firm	3,378	322,252			0.095
11	COM26 - Private Area Lighting Dusk to Dawn Burning	426	92,585	45	9,467	0.217
12	CO905 - Commercial Firm	472	170,411	1	472,000	0.361
13	COM46 - Special Contract	13	3,059	26	500	0.235
14	COPA1 - New Lamp-Customer Owns 0%-A	13	8,450	2	6,500	0.650
15	COPA2 - New Lamp-Customer Owns 0%-B	211	68,437	11	19,182	0.324
16	COPB2 - New Lamp-Customer Owns 25%	13	5,720	4	3,250	0.440
17	COPC2 - New Lamp-Customer Owns 50%-B	3	774	1	3,000	0.258
18	COPD2 - New Lamp-Customer Owns 75%-B	103	12,997	18	5,722	0.126
19	COPE1 - New Lamp-Customer Owns 100%-A	183	15,342	12	15,250	0.084
20	COPE2 - New Lamp-Customer Owns 100%-B	1,965	139,716	126	15,595	0.071
21	Renewable Energy Standard Adjustment		(1,564,949)			
22	Demand Side Management		(2,918,661)			
23	CO710 - Small General Service-No Demand	55,225	7,454,437	7,302	7,563	0.135
24	Peak View		2,594,246			
25	Excess Deferred Income Taxes		(106,173)			
26	CO711 - Small General Service-Demand	127,064	15,252,770	3,138	40,492	0.120
27	CO720 - Large General Service-Secondary	323,229	32,761,041	684	472,557	0.101
28	CO725 - Large General Service-Primary	67,387	4,624,907	31	2,173,774	0.069
29	CO735 - Large Power Service-Primary	88,008	6,238,173	3	29,336,000	0.071
30	CO736 - Large Power Service-Transmission	799	249,362	1	799,000	0.312
31	CO770 - Irrigation	6,447	908,269	269	23,967	0.141
41	TOTAL Billed Small or Commercial	718,128	71,502,878	11,952	36,805,097	0.100
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	(1,380)	26,379,184			(19.115)
43	TOTAL Small or Commercial	716,748	97,882,062	11,952	59,969	0.137

Name of Respondent:
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12/31/2025

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End of: 2025/ Q4

FOOTNOTE DATA

[\(a\)](#) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Commercial revenues

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	CO710 - Small General Serv-No Demand	18	2,305	2	9,000	0.128
2	CO936 - Large Power Service-Transmission-Time of Use	34,352	2,933,808	2	17,176,000	0.085
3	CO937 - Generation Supplemental Service-Transmission	165	100,762	1	165,000	0.611
4	CO938 - Industrial Firm	27,505	2,116,172	2	13,752,500	0.077
5	COM26 - Private Area Lighting Dusk to Dawn Burning	37	8,323	6	6,167	0.225
6	COPA2 - New Lamp-Customer Owns 0%-B	1	258			0.258
7	COPD2 - New Lamp-Customer Owns 75%-B	6	804	1	6,000	0.134
8	COPE2 - New Lamp-Customer Owns 100%-B	21	1,730	4	5,250	0.082
9	Renewable Energy Standard Adjustment		(584,269)			
10	Demand Side Management		(1,090,088)			
11	Peak View		1,244,953			
12	CO711 - Small General Service-Demand	452	52,759	6	75,333	0.117
13	Excess Deferred Income Taxes		(23,965)			
14	CO720 - Large General Service-Secondary	23,180	2,338,105	22	1,053,636	0.101
15	CO725 - Large General Service-Primary	8,978	744,160	4	2,244,500	0.083
16	CO735 - Large Power Service-Primary	140,351	9,327,859	3	46,783,667	0.066
17	CO736 - Large Power Sev-Transmission	102,409	6,703,559			0.065
18	CO878 - Net Metering - NonRes to 1400kW PV	65	42,256			0.650
19	CO881 - Net Metering - NonRes over 1400kW PV		867,545	1		
20	CO920 - Large General Service - Secondary-Time of Use	72	21,130	1	72,000	0.293
41	TOTAL Billed Large (or Ind.) Sales	337,612	24,808,166	55	6,138,400	0.073
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	485	12,399,482			25.566
43	TOTAL Large (or Ind.)	338,097	37,207,648	55	6,147,218	0.110

Name of Respondent:
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Date of Report:
12/31/2025

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End of: 2025/ Q4

FOOTNOTE DATA

[\(a\)](#) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Industrial revenues

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.
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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	CO784 - Emerging Energy Efficiency Lighting Technology Option Provision	4,144	752,253	51	81,255	0.182
2	COM28 - Customer Owned Street Lighting	405	85,437	37	10,946	0.211
3	COM41 - Traffic Signals-Flashers		1,591	22		
4	COPA1 - New Lamp-Customer Owns 0%-A	33	22,381	1	33,000	0.678
5	COPA2 - New Lamp-Customer Owns 0%-B	84	29,447	4	21,000	0.351
6	COPB2 - New Lamp-Customer Owns 25%	8	3,437	3	2,667	0.430
7	COPC2 - New Lamp-Customer Owns 50%-B	2	243			0.122
8	COPD2 - New Lamp-Customer Owns 75%-B	21	2,491	5	4,200	0.119
9	COPE1 - New Lamp-Customer Owns 100%-A	524	38,794	5	104,800	0.074
10	COPE2 - New Lamp-Customer Owns 100%-B	1,018	72,635	52	19,577	0.071
11	Renewable Energy Standard Adjustment		(19,148)			
41	TOTAL Billed Public Street and Highway Lighting	6,239	989,561	180	34,661	0.159
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	6,239	989,561	180	34,661	0.159

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.
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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	CO710 - Small General Service-No Demand	613	78,718	52	11,788	0.128
2	CO711 - Small General Service-Demand	2,167	257,172	44	49,250	0.119
3	CO720 - Large General Service-Secondary	14,582	1,440,575	16	911,375	0.099
4	CO725 - Large General Service-Primary	2,763	251,934	2	1,381,500	0.091
5	CO735 - Large Power Service-Primary	24,602	1,583,516	1	24,602,000	0.064
6	CO736 - Large Power Service-Transmission	6,588	543,473	1	6,588,000	0.082
7	CO780 - Large Power Service-Special Contract	5,315	310,752	1	5,315,000	0.058
8	CO782 - Traffic Lights-Metered	217	31,551	57	3,807	0.145
9	CO783 - Traffic Signals-City of Pueblo	268	45,165	103	2,602	0.169
10	CO876 - Net Metering-NonResidential less than 10 KW-Photovoltaic	27	3,248	1	27,000	0.120
11	CO877 - Net Metering-NonRes 10 to 50KW-Photovoltaic	32	3,951	2	16,000	0.123
12	CO878 - Net Metering-NonRes to 1400kw PV	1,606	157,915	4	401,500	0.098
13	CO879 - Net Metr-NonRes to 1400 KW PV	6,782	371,500	1	6,782,000	0.055
14	CO881 - Net Metrng-NonRes over 1400 PV	20,737	1,276,784	1	20,737,000	0.062
15	CO904 - Large General Service Electric Vehicle Time of Day	41	22,830	1	41,000	0.557
16	CO920 - Large General Service-Secondary-Time of Use	5,656	504,186	2	2,828,000	0.089
17	CO925 - Large General Service-T-Time of Use	7,130	528,192	1	7,130,000	0.074
18	CO930 - Large Power Service-Secondary-Time of Use	898	149,107	1	898,000	0.166
19	CO938 - Industrial Firm	(838)	(66,518)	1	(838,000)	0.079
20	Demand Side Management		(328,112)			
21	Excess Deferred Income Taxes		(14,815)			
22	Peak View		381,785			
23	Renewable Energy Standard Adjustment		(177,396)			
41	TOTAL Billed Other Sales to Public Authorities	99,186	7,355,513	292	339,678	0.074
42	TOTAL Unbilled Rev. (See Instr. 6)	(1,039)	3,830,339			(3.687)
43	TOTAL	98,147	11,185,852	292	336,120	0.114

SALES OF ELECTRICITY BY RATE SCHEDULES

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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)
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35						
36						
37						
38						
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40						
41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL			(10)		

Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
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SALES OF ELECTRICITY BY RATE SCHEDULES

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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)
41	TOTAL Billed - All Accounts	1,755,775	193,619,782	102,210	6,579,450	0.556
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	(1,619)	64,965,752			73.738
43	TOTAL - All Accounts	1,754,156	258,585,534	102,210	6,584,598	0.707

SALES FOR RESALE (Account 447)

- Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326).
- Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
- In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

 LF - for long-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 seller can unilaterally get out of the contract.

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

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

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

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

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

 AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
- 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).
- 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.
- For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
- Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
- Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
- 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.
- 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)		Megawatt Hours Sold (g)	REVENUE			Total (\$) (h++)(k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)	
1	Alltop Energy	OS	2				1,068		39,256		39,256
2	Arizona Electric Power	OS					342		13,708		13,708
3	Basin Electric Power	OS					200		9,000		9,000
4	Colorado Springs Utilities - Wind	LF					202,857		3,902,256		3,902,256
5	Colorado Spring Utilities	OS	2				21,415		1,063,125		1,063,125
6	Dynasty Power	OS	2				40		480		480
7	The Energy Authority	OS	2				3,295		110,900		110,900
8	The Energy Authority (MEAN)	OS	2				410		17,130		17,130
9	Guzman Energy	OS	2				12,334		449,297		449,297
10	Guzman Renewables	OS	2				200		10,000		10,000
11	Macquarie Energy	OS	2				82		1,712		1,712
12	Morgan Stanley	OS	2				2,334		76,082		76,082
13	Mercuria	OS	2				480		15,752		15,752
14	North West Power Pool	OS	2				134		8,304		8,304
15	PacifiCorp	OS	2				1,800		106,800		106,800
16	Platte River Power Authority	OS	2				8,105		347,080		347,080
17	Public Service Company of Colorado	OS	2				36,870		1,725,454		1,725,454
18	Public Service Company of New Mexico	OS	2				3,567		134,267		134,267
19	Southwest Power Pool - WEIS	OS	SPP RTO							7,767,391	7,767,391
20	Transalta Energy	OS	2				50		2,350		2,350
21	Tri-State Generation	OS	2				7,450		319,325		319,325
22	Uniper Power	OS	2				115,420		4,687,768		4,687,768
23	Western Area Power Administration - Colorado River Storage Project	OS	2				33,706		1,929,453		1,929,453
24	Western Area Power Administration - Loveland Area Power	OS	2				11,822		692,478		692,478
25	Retail Customer									(1,810,016)	(1,810,016)
15	Subtotal - RQ						0	0	0	0	0
16	Subtotal-Non-RQ						463,981	0	15,661,977	5,957,375	21,619,352
17	Total						463,981		15,661,977	5,957,375	21,619,352

Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
(1) An Original
(2) A Resubmission

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: OtherChargesRevenueSalesForResale

Energy Imbalance Market charges

(b) Concept: OtherChargesRevenueSalesForResale

Colorado Electric shares a portion of Marketing Sales margin with its retail customers through the Energy Cost Adjustment

Name of Respondent:
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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering		
5	(501) Fuel		
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses		
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)		
14	Maintenance		
15	(510) Maintenance Supervision and Engineering		
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant		
18	(513) Maintenance of Electric Plant		
18.1	(513.1) Maintenance of Computer Hardware		
18.2	(513.2) Maintenance of Computer Software		
18.3	(513.3) Maintenance of Communication Equipment		
19	(514) Maintenance of Miscellaneous Steam Plant		
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)		
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)		
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		
38.1	(531.1) Maintenance of Computer Hardware		
38.2	(531.2) Maintenance of Computer Software		
38.3	(531.3) Maintenance of Communication Equipment		
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) Maintenance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
56.1	(544.1) Maintenance of Computer Hardware		
56.2	(544.2) Maintenance of Computer Software		
56.3	(544.3) Maintenance of Communication Equipment		
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	358,879	461,381
63	(547) Fuel	20,544,397	18,541,453
64	(548) Generation Expenses	580,261	183,811
65	(549) Miscellaneous Other Power Generation Expenses	840,616	1,707,034
66	(550) Rents	1,095	502,470
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	22,325,248	21,396,149
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	50,128	2,266
70	(552) Maintenance of Structures	46,417	123,654
71	(553) Maintenance of Generating and Electric Plant	3,820,977	2,576,102
71.1	(553.1) Maintenance of Computer Hardware	1,371	
71.2	(553.2) Maintenance of Computer Software	10,204	
71.3	(553.3) Maintenance of Communication Equipment	6,724	
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	209,878	738,953
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	4,145,699	3,440,975
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	26,470,947	24,837,124
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	106,602,266	98,962,064
76.1	(555.1) Power Purchased for Storage Operations		
76.2	(555.2) Bundled Environmental Credits		
76.3	(555.3) Unbundled Environmental Credits		
77	(556) System Control and Load Dispatching	1,390,680	1,537,870
78	(557) Other Expenses	1,425	264
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	107,994,371	100,500,198
79.1	F. Solar Generation		
79.2	Operation		
79.3	(558.1) Operation Supervision and Engineering	1,251,482	
79.4	(558.2) Solar Panel Generation and Other Plant Operating Expenses	3,813	
79.6	(558.4) Rents		
79.7	TOTAL Operation (Enter Total of lines 79.3 thru 79.6)	1,255,295	
79.8	Maintenance		
79.9	(558.6) Maintenance Supervision and Engineering		
79.10	(558.7) Maintenance of Solar Panels, Structures, and Equipment		
79.11	(558.8) Maintenance of Computer Hardware		
79.12	(558.9) Maintenance of Computer Software		
79.13	(558.10) Maintenance of Communication Equipment		
79.14	(558.11) Maintenance of Miscellaneous Solar Generation Plant		
79.15	TOTAL Maintenance (Enter Total of lines 79.9 thru 79.14)		
79.16	TOTAL Power Production Expenses-Solar (total of lines 79.7 & 79.15)	1,255,295	

79.17	G. Wind Generation		
79.18	Operation		
79.19	(558.13) Operation Supervision and Engineering		
79.20	(558.14) Wind Turbine Generation and Other Plant Operating Expenses		
79.21	(558.16) Rents		
79.22	TOTAL Operation (Enter Total of lines 79.19 thru 79.21)		
79.23	Maintenance		
79.24	(558.18) Maintenance Supervision and Engineering		
79.25	(558.19) Maintenance of Wind Turbines, Structures, and Equipment		
79.26	(558.20) Maintenance of Computer Hardware		
79.27	(558.21) Maintenance of Computer Software		
79.28	(558.22) Maintenance of Communication Equipment		
79.29	(558.23) Maintenance of Miscellaneous Wind Generation Plant		
79.30	TOTAL Maintenance (Enter Total of lines 79.24 thru 79.29)		
79.31	TOTAL Power Production Expenses-Wind (total of lines 79.22 & 79.30)		
79.32	H. Other Renewable Generation		
79.33	Operation		
79.34	(559.1) Operation Supervision and Engineering		
79.35	(559.2) Other Miscellaneous Generation and Other Plant Operating Expenses		
79.36	(559.3) Fuel		
79.37	(559.4) Rents		
79.38	TOTAL Operation (Enter Total of lines 79.34 thru 79.37)		
79.39	Maintenance		
79.40	(559.6) Maintenance Supervision and Engineering		
79.41	(559.7) Maintenance of Structures		
79.42	(559.9) Maintenance of Boilers		
79.43	(559.10) Maintenance of Generating and Electric Equipment		
79.44	(559.12) Maintenance of Computer Hardware		
79.45	(559.13) Maintenance of Computer Software		
79.46	(559.14) Maintenance of Communication Equipment		
79.47	(559.15) Maintenance of Miscellaneous Renewable Production Plant		
79.48	TOTAL Maintenance (Enter Total of lines 79.40 thru 79.47)		
79.49	TOTAL Power Production Expenses-Other Renewable (total of lines 79.38 & 79.48)		
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74, 79, 79.16, 79.31, & 79.49)	135,720,613	125,337,322
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	311,734	403,218
85	(561.1) Load Dispatch-Reliability	96,024	100,354
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	941,999	707,270
87	(561.3) Load Dispatch-Transmission Service and Scheduling	13,908	26,666
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	670,488	677,310
90	(561.6) Transmission Service Studies	(4,755)	9,694
91	(561.7) Generation Interconnection Studies	81,272	90,214
92	(561.8) Reliability, Planning and Standards Development Services	129,208	98,839
93	(562) Station Expenses	22,874	2,861
94	(563) Overhead Lines Expenses	9,887	1,050
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	1,717,062	2,195,835
97	(566) Miscellaneous Transmission Expenses	64,249	67,305
98	(567) Rents	86,713	86,985
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	4,140,663	4,467,601
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	112	56
102	(569) Maintenance of Structures	100	241
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	868,903	781,400
108	(571) Maintenance of Overhead Lines	154,084	215,692
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of Lines 101 thru 110)	1,023,199	997,389
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	5,163,862	5,464,990
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation	174,206	148,092
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)	174,206	148,092
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)	174,206	148,092
131.1	4. ENERGY STORAGE EXPENSES		
131.2	Operation		
131.3	(577.1) Operation Supervision and Engineering		
131.4	(577.2) Operation of Energy Storage Equipment		
131.5	(577.3) Storage Fuel		
131.6	(577.4) Rents		
131.7	Total Operation (Lines 131.3 thru 131.6)		
131.8	Maintenance		
131.9	(578.1) Maintenance Supervision and Engineering		
131.10	(578.2) Maintenance of Energy Storage Equipment and Structures		
131.11	(578.3) Maintenance of Computer Hardware		
131.12	(578.4) Maintenance of Computer Software		
131.13	(578.5) Maintenance of Communication Equipment		
131.14	(578.6) Maintenance of Miscellaneous Other Energy Storage Plant		
131.15	Total Maintenance (Lines 131.9 thru 131.14)		
131.16	TOTAL Energy Storage Expenses (Total of 131.7 and 131.15)		
132	5. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	930,531	868,548
135	(581) Load Dispatching	518,659	490,141
136	(582) Station Expenses	20,896	11,022
137	(583) Overhead Line Expenses	1,309,558	774,383
138	(584) Underground Line Expenses	905,814	992,879
139	(585) Street Lighting and Signal System Expenses	(10,524)	67,561
140	(586) Meter Expenses	1,037,835	872,886
141	(587) Customer Installations Expenses	941,332	1,136,269
142	(588) Miscellaneous Expenses	3,961,186	3,621,208
143	(589) Rents	15,519	14,298
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	9,630,806	8,849,195
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	3,173	17,182
147	(591) Maintenance of Structures		

148	(592) Maintenance of Station Equipment		989,763	944,826
148.1	(592.2) Maintenance of Computer Hardware			
148.2	(592.3) Maintenance of Computer Software			
148.3	(592.4) Maintenance of Communication Equipment			
149	(593) Maintenance of Overhead Lines		5,933,831	6,564,961
150	(594) Maintenance of Underground Lines		397,753	226,181
151	(595) Maintenance of Line Transformers			6,709
152	(596) Maintenance of Street Lighting and Signal Systems		256,228	33,261
153	(597) Maintenance of Meters		18,276	59,889
154	(598) Maintenance of Miscellaneous Distribution Plant			20,549
155	TOTAL Maintenance (Total of Lines 146 thru 154)		7,599,024	7,873,558
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)		17,229,830	16,722,753
157	6. CUSTOMER ACCOUNTS EXPENSES			
158	Operation			
159	(901) Supervision		99,142	98,888
160	(902) Meter Reading Expenses		83,426	207,180
161	(903) Customer Records and Collection Expenses		1,683,037	1,679,180
162	(904) Uncollectible Accounts		1,335,211	1,241,989
163	(905) Miscellaneous Customer Accounts Expenses		39,835	36,746
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)		3,240,651	3,263,983
165	7. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES			
166	Operation			
167	(907) Supervision		218,772	186,733
168	(908) Customer Assistance Expenses		136,710	83,196
169	(909) Informational and Instructional Expenses		357,829	352,340
170	(910) Miscellaneous Customer Service and Informational Expenses		1,930	846
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)		715,241	623,115
172	8. SALES EXPENSES			
173	Operation			
174	(911) Supervision			
175	(912) Demonstrating and Selling Expenses		16,834	325
176	(913) Advertising Expenses		97	229
177	(916) Miscellaneous Sales Expenses			
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)		16,931	554
179	9. ADMINISTRATIVE AND GENERAL EXPENSES			
180	Operation			
181	(920) Administrative and General Salaries		11,556,305	11,584,951
182	(921) Office Supplies and Expenses		2,915,221	2,745,309
183	(Less) (922) Administrative Expenses Transferred-Credit		2,584,423	2,822,164
184	(923) Outside Services Employed		2,091,142	2,136,483
185	(924) Property Insurance		1,298,117	1,132,136
186	(925) Injuries and Damages		3,000,047	2,395,943
187	(926) Employee Pensions and Benefits		5,236,894	5,062,001
188	(927) Franchise Requirements			
189	(928) Regulatory Commission Expenses		1,703,275	1,447,193
190	(929) (Less) Duplicate Charges-Cr.		120,060	119,375
191	(930.1) General Advertising Expenses		197,655	260,069
192	(930.2) Miscellaneous General Expenses		576,886	734,361
193	(931) Rents		1,249,791	1,599,177
194	TOTAL Operation (Enter Total of Lines 181 thru 193)		27,120,850	26,156,084
195	Maintenance			
196	(935) Maintenance of General Plant		2,816,017	2,630,905
196.1	(935.1) Maintenance of Computer Hardware		10	
196.2	(935.2) Maintenance of Computer Software		39,742	
196.3	(935.3) Maintenance of Communication Equipment			
196.4	TOTAL Maintenance (Enter Total of lines 196 thru 196.3)		2,855,769	2,630,905
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196.4)		29,976,619	28,786,989
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 131.16, 156, 164, 171, 178, and 197)		192,237,953	180,347,798

Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
(1) An Original
(2) A Resubmission

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ 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 for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

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

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

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

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatt-hours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the megawatt-hours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) the megawatt-hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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, in column (m). Explain in a footnote all 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 power exchanges, report in column (n) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in 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 Purchases on Page 401, line 10. The total amount in 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 Page 401, line 13.
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)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total (k+l+m) of Settlement (\$) (n)	
1	Altop Energy	OS					13,706						414,873		414,873
2	Public Service Company of Colorado	OS					14,252						510,739		510,739
3	Arizona Electric Power	OS					5,141						82,490		82,490
4	Basin Electric Power	OS					1,140						41,870		41,870
5	Colorado Springs Utilities	OS					27,823						1,199,354		1,199,354
6	Community Solar Garden	OS					24,537								
7	Dynasty Power	OS					2,449						82,480		82,480
8	The Energy Authority (MEAN)	OS					253						7,590		7,590
9	Guzman Energy	OS					27,742						1,067,546		1,067,546
10	Idaho Power	OS					50						50		50
11	Macquarie Energy	OS					1,160						28,480		28,480
12	MAG Energy	OS					80						2,000		2,000
13	Mercuria	OS					675						14,880		14,880
14	Morgan Stanley	OS					180						5,400		5,400
15	Mountain View	OS					690						62,748		62,748
16	North West Power Pool	OS					63						8,672		8,672
17	PacifiCorp	OS					719						31,435		31,435
18	Platte River Power Authority	OS					1,345						60,390		60,390
19	Public Service Company of New Mexico	OS					4,810						74,855		74,855
20	Salt River Project	OS					354						25,733		25,733
21	Southwest Power Pool	OS											4,843		4,843
22	Southwest Power Pool - WEIS		SPP RTO											3,071,653	3,071,653
23	Tenaska Power	OS					60						2,880		2,880
24	Transalta Energy	OS					89						1,450		1,450
25	Tri-State Generation	OS					7,813						335,763		335,763
26	United Power	OS					42						1,550		1,550
27	Western Area Power Administration - Western Area Colorado Missouri	OS					25						50		50
28	Western Area Power Administration - Colorado River Storage Project	OS					9,768						162,249		162,249

29	Retail Customer Generation	OS									694,800		694,800	
30	⁴³ Black Hills Colorado IPP - PAGES	LF		200	200	200	1,072,012				41,289,392	48,725,044	90,014,436	
31	⁴³ Black Hills Electric Generation - Busch Ranch Wind Farm	LU					34,683					1,784,139	1,784,139	
32	⁴³ Black Hills Electric Generation - Busch Ranch II Wind Farm	LU					138,970					3,007,303	3,007,303	
33	⁴⁶ Platte River Power Authority - Wind	LU					205,382					3,799,565	3,799,565	
15	TOTAL						1,596,013		3,009,282	3,009,282	41,289,392	62,241,221	3,071,653	106,602,266

Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
(1) An Original
(2) A Resubmission

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Affiliate transaction

(b) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Affiliate transaction

(c) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Affiliate transaction

(d) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Contract Agreement

(e) Concept: EnergyChargesOfPurchasedPower

Renewable Energy Buy-back from Customers


(f) Concept: OtherChargesOfPurchasedPower

Energy Imbalance Market Charges

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
5. In column (e), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatt-hours 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 to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

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 OF ENERGY		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
									Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total Revenues (\$) (k+l+m) (n)
1	Arkansas River Power Authority	Black Hills Colorado Electric	Arkansas River Power Authority	FNO	Network	Various	ARPA		17,202	17,202		358,046	12,497	370,543
2	Tri State Generation & Transmission	Black Hills Colorado Electric	Tri State Generation & Transmission	FNO	Network	Various	BHCE		56,678	56,678		739,083	39,443	778,526
3	^(a) Black Hills Colorado Electric	Black Hills Colorado Electric	Black Hills Colorado Electric	FNS	Network	Various	BHCE		1,873,324	1,873,324				
4	Western Area Power Administration - CRSP	Black Hills Colorado Electric	Western Area Power Administration-CRSP	LFP	7	Craig	TSGTWSTATION		4,450	4,450	190,080		5,080	195,160
5	Tri State Generation & Transmission	Black Hills Colorado Electric	Tri State Generation & Transmission	LFP	7	MIDW	TSGTWSTATION		18,812	18,812	395,560		13,398	408,958
6	Arkansas River Power Authority	Black Hills Colorado Electric	Arkansas River Power Authority	OS		Various	ARPA		22,048	22,048	61,513			61,513
7	Tri State Generation & Transmission	Black Hills Colorado Electric	Tri State Generation & Transmission	OS		MIDW	TSGTWSTATION		56,678	56,678	157,194			157,194
8	Pueblo Depot Authority	Black Hills Colorado Electric	Pueblo Depot Authority	OS		MIDW	PDA		7,542	7,542	21,041			21,041
9	Tri State Generation & Transmission	Black Hills Colorado Electric	Tri State Generation & Transmission	SFP	7	BOON	BHCE		56	56		735	23	758
10	Tri State Generation & Transmission	Black Hills Colorado Electric	Tri State Generation & Transmission	SFP	7	MIDW	BHCE		76	76		998	31	1,029
11	Tri State Generation & Transmission	Black Hills Colorado Electric	Tri State Generation & Transmission	SFP	7	MIDW	TSGTWSTATION		11,430	11,430		150,126	4,679	154,805
12	Western Area Power Administration - CRSP	Black Hills Colorado Electric	Tri State Generation & Transmission	SFP	7	MIDW	BHCE		2,276	2,276		22,289	661	22,950
13	Western Area Power Administration - CRSP	Black Hills Colorado Electric	Western Area Power Administration - CRSP	SFP	7	MIDW	TSGTWSTATION		2	2		20	1	21
14	Altop Energy	Black Hills Colorado Electric	Western Area Power Administration - CRSP	SFP	7	CCW	MIDW		25	25		37	8	45
15	^(a) Black Hills Power, Inc.	Black Hills Colorado Electric	Altop Energy	NF	8	BHCE	MIDW		165	165		247	46	293
16	^(a) Black Hills Power, Inc.	Black Hills Colorado Electric	Black Hills Power	NF	8	MIDW	BHCE		140	140		210	39	249
17	^(a) Black Hills Colorado Electric	Black Hills Colorado Electric	Black Hills Power	NF	8	BHCE	MIDW		268,238	268,238		402,357	89,408	491,765
18	^(a) Black Hills Colorado Electric	Black Hills Colorado Electric	Black Hills Colorado Electric	NF	8	CCW	BHCE		132	132		198	44	242
19	^(a) Black Hills Colorado Electric	Black Hills Colorado Electric	Black Hills Colorado Electric	NF	8	MIDW	BHCE		129,127	129,127		193,690	43,040	236,730
20	^(a) Black Hills Colorado Electric	Black Hills Colorado Electric	Black Hills Colorado Electric	NF	8	READER	BHCE		1,049	1,049		1,573	350	1,923
21	Colorado Springs Utilities	Black Hills Colorado Electric	Black Hills Colorado Electric	NF	8	BHCE	MIDW		28,320	28,320		42,480	9,005	51,485
22	Dynasty Power Inc.	Black Hills Colorado Electric	Colorado Springs Utilities	NF	8	READER	MIDW		17	17		25	8	33
23	Guzman Energy LLC	Black Hills Colorado Electric	Dynasty Power Inc.	NF	8	BHCE	MIDW		13	13		19	4	23
24	Guzman Energy LLC	Black Hills Colorado Electric	Guzman Energy LLC	NF	8	BHCE	TSGTWSTATION		107	107		161	35	196
25	Guzman Energy LLC	Black Hills Colorado Electric	Guzman Energy LLC	NF	8	BOON	MIDW		90,771	90,771		136,157	29,525	165,682
26	Guzman Energy LLC	Black Hills Colorado Electric	Guzman Energy LLC	NF	8	BOON	TSGTWSTATION		101,078	101,078		151,617	32,878	184,495

27	Guzman Energy LLC	Black Hills Colorado Electric	Guzman Energy LLC	NF	8	CCW	MIDW			36	36		54	12	66
28	Guzman Energy LLC	Black Hills Colorado Electric	Guzman Energy LLC	NF	8	MIDW	BHCE			28	28		42	9	51
29	Guzman Energy LLC	Black Hills Colorado Electric	Guzman Energy LLC	NF	8	MIDW	TSGTWSTATION			78,431	78,431		117,647	25,512	143,159
30	Guzman Energy LLC	Black Hills Colorado Electric	Guzman Energy LLC	NF	8	MIDW	BOON			162	162		243	53	296
31	Guzman Energy LLC	Black Hills Colorado Electric	Guzman Energy LLC	NF	8	TSGTWSTATION	BHCE			13	13		20	4	24
32	Guzman Energy LLC	Black Hills Colorado Electric	Guzman Energy LLC	NF	8	TSGTWSTATION	MIDW			11,290	11,290		16,935	3,672	20,607
33	Public Service Company of Colorado	Black Hills Colorado Electric	Guzman Energy LLC	NF	8	MIDW	TSGTWSTATION			6,239	6,239		9,359	2,935	12,294
34	Tri State Generation & Transmission	Black Hills Colorado Electric	Tri State Generation & Transmission	NF	8	MIDW	BHCE			4,398	4,398		6,597	1,419	8,016
35	Tri State Generation & Transmission	Black Hills Colorado Electric	Tri State Generation & Transmission	NF	8	MIDW	TSGTWSTATION			171,805	171,805		257,708	55,449	313,157
36	Tri State Generation & Transmission	Black Hills Colorado Electric	Tri State Generation & Transmission	NF	8	TSGTWSTATION	MIDW			46,103	46,103		69,155	14,879	84,034
37	WestConnect	Black Hills Colorado Electric	Altop Energy	NF	8	READER	MIDW			366	366		610	114	724
38	WestConnect	Black Hills Colorado Electric	Guzman Energy LLC	NF	8	BOON	MIDW			247	247		347	76	423
39	WestConnect	Black Hills Colorado Electric	Guzman Energy LLC	NF	8	BOON	TSGTWSTATION			96	96		135	29	164
40	WestConnect	Black Hills Colorado Electric	Guzman Energy LLC	NF	8	MIDW	CCW			15	15		21	5	26
41	WestConnect	Black Hills Colorado Electric	TransAlta Energy Marketing U.S.Inc.	NF	8	BOON	MIDW			57	57		62	17	79
42	WestConnect	Black Hills Colorado Electric	TransAlta Energy Marketing U.S.Inc.	NF	8	CCW	MIDW			240	240		261	72	333
43	Arkansas River Power Authority	Black Hills Colorado Electric	Arkansas River Power Authority	AD									(49,583)		(49,583)
44	Pueblo Depot Authority	Black Hills Colorado Electric	Pueblo Depot Authority	AD									(11,559)	(407)	(11,966)
45	Tri State Generation & Transmission	Black Hills Colorado Electric	Tri State Generation & Transmission	AD									(101,862)	(4,996)	(106,858)
46	Western Area Power Administration - CRSP	Black Hills Colorado Electric	Western Area Power Administration-CRSP	AD									(60,025)	(2,250)	(62,275)
47	Tri State Generation & Transmission	Black Hills Colorado Electric	Tri State Generation & Transmission	AD									(699,866)	(34,800)	(734,666)
48	Tri State Generation & Transmission	Black Hills Colorado Electric	Tri State Generation & Transmission	AD									(3)	(459)	(462)
49	Western Area Power Administration - CRSP	Black Hills Colorado Electric	Western Area Power Administration - CRSP	AD										(191)	(191)
50	 Black Hills Colorado Electric	Black Hills Colorado Electric	Black Hills Colorado Electric	AD										(34,862)	(34,862)
51	 Black Hills Power	Black Hills Colorado Electric	Black Hills Power	AD										(30)	(30)
52	Colorado Springs Utilities	Black Hills Colorado Electric	Colorado Springs Utilities	AD										(2,585)	(2,585)
53	Dynasty Power Inc.	Black Hills Colorado Electric	Dynasty Power Inc.	AD										(14)	(14)
54	Guzman Energy LLC	Black Hills Colorado Electric	Guzman Energy LLC	AD										(22,699)	(22,699)
55	Public Service Company of Colorado	Black Hills Colorado Electric	Public Service Company of Colorado	AD										(3,144)	(3,144)
35	TOTAL									3,009,282	3,009,282	825,388	1,756,366	 278,023	2,859,777

Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
(1) An Original
(2) A Resubmission

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: PaymentByCompanyOrPublicAuthority

Nonfirm transmission provided to self, therefore, no revenue received.

(b) Concept: PaymentByCompanyOrPublicAuthority

Affiliate transaction

(c) Concept: PaymentByCompanyOrPublicAuthority

Affiliate transaction

(d) Concept: PaymentByCompanyOrPublicAuthority

Affiliate transaction

(e) Concept: PaymentByCompanyOrPublicAuthority

Affiliate transaction

(f) Concept: PaymentByCompanyOrPublicAuthority

Affiliate transaction

(g) Concept: PaymentByCompanyOrPublicAuthority

Affiliate transaction

(h) Concept: PaymentByCompanyOrPublicAuthority

Nonfirm transmission provided to self, therefore, no revenue received.

(i) Concept: PaymentByCompanyOrPublicAuthority

Affiliate transaction

(j) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Ancillary charges

Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
(1) An Original
(2) A Resubmission

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ 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					
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Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
(1) An Original
(2) A Resubmission

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ 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		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Public Service Company of Colorado	LFP	10,743	10,743			841,099	841,099
2	Basin Electric	NF	2,362	2,362		5,117		5,117
3	Black Hills Colorado Electric	NF	398,546	398,546		693,401		693,401
4	Western Area Power Administration - Rocky Mountain	NF	35,348	35,348		102,985		102,985
5	Public Service Company of Colorado	NF	2,591	2,591		39,369		39,369
6	Salt River Project	NF	50	50		3,764		3,764
7	Tucson Electric Power Company	NF	65	65		598		598
8	Tri-State Generation & Transmission	NF	(372)	(372)		4,604		4,604
9	Western Area Power Administration - Desert Southwest	NF	2	2		294		294
10	Western Area Power Administration - Loveland	NF	80	80		434		434
11	Western Area Colorado Missouri Losses	NF	649	649		24,681		24,681
12	Power Purchase and Wheeling	NF	156	156		716		716
	TOTAL		450,220	450,220		875,963	841,099	1,717,062

(a) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Affiliate charges

(b) Concept: OtherChargesTransmissionOfElectricityByOthers

Ancillary charges

Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
(1) An Original
(2) A Resubmission

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	19,058
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than \$5,000	
6	Directors' Fees and Expenses	251,683
7	Bank Fees	139,892
8	Travel	12,117
9	Amortization of Deferred Financing Costs	73,743
10	Consulting Fees	47,972
11	Software Service Expense	13,767
12	Sponsorships	6,095
13	Miscellaneous Other	12,559
46	TOTAL	576,886

Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
(1) An Original
(2) A Resubmission

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ Q4

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

- 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).
- 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.
- 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.
- 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					
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
5.1	Solar Production Plant					
5.2	Wind Production Plant	5,319,473	221,474			5,540,947
5.3	Other Renewable Production Plant					
6	Other Production Plant	9,718,256	94,209			9,812,465
7	Transmission Plant	8,392,927		73,955		8,466,882
8	Distribution Plant	11,985,060				11,985,060
9	Regional Transmission and Market Operation					
9.1	Energy Storage Plant					
10	General Plant	4,478,796		469,512		4,948,308
11	Common Plant-Electric					
12	TOTAL	39,894,512	315,683	543,467		40,753,662

B. Basis for Amortization Charges

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	Intangible Plant						
13	(303)Miscellaneous Intangible Plant	329					
14	SUBTOTAL INTANGIBLE	329					
15	Steam Production Plant						
16	(311)Structures and Improvements		80 years	12%	4.82%		
17	(312)Boiler Plant Equipment		45 years	12%	18.33%		
18	(314)Turbogenerator Units		55 years	12%	10.22%		
19	(315)Accessory Electric Equipment		50 years	12%	16.76%		
20	(316)Miscellaneous Power Plant Equipment		25 years	12%	3.72%		
21	SUBTOTAL STEAM PROD						
22	Wind Production						
23	(338.21) Structures and Improvements	16,513	45 years	10%	4.7%		16 years
24	(338.23) Wind Turbines	68,972	45 years	10%	4.7%		16 years
25	(338.24) Wind Towers and Fixtures	22,993	45 years	10%	4.7%		16 years
26	(338.26) Collector System	8,567	45 years	10%	4.7%		16 years
27	(338.29) Other Accessory Electrical Equipment	70	55 years	10%	5.45%		14 years
28	(338.32) Communication	122	15 years		6.67%		5 years

	Equipment						
29	SUBTOTAL WIND PRODUCTION	117,237					
30	Other Production Plant						
31	(341)Structures and Improvements	16,957	50 years		5%	2.44%	28 years
32	(342)Fuel Holders, Producers and Accessories	9,275	60 years		10%	6.47%	27 years
33	(343)Prime Movers	2,273	20 years		10%	4.64%	4 years
34	(344)Generators	261,180	45 years		10%	3.03%	26 years
35	(345)Accessory Electric Equipment	18,312	20 years		10%	3.91%	26 years
36	(345.1) Computer Hardware	381	5 years			20%	2 years
37	(345.2) Communication Equipment	902	15 years			6.67%	5 years
38	(346)Miscellaneous Power Plant Equipment	2,674	20 years				31 years
39	SUBTOTAL OTHER PRODUCTION PLANT	311,954					
40	Transmission Plant						
41	(351.3) Communication Equipment	5,893	15 years			6.67%	5 years
42	(352)Structures and Improvements	13,020	60 years		5%	1.8%	48 years
43	(353)Station Equipment	124,903	60 years		15%	1.84%	47 years
44	(354)Towers and Fixtures						45 years
45	(355)Poles and Fixtures	116,083	48 years		40%	3.81%	43 years
46	(356)Overhead Conductors and Devices	70,279	50 years		30%	3.25%	42 years
47	(357)Underground Conduit		45 years			2.22%	
48	(358)Underground Conductors and Devices		45 years			2.17%	
49	(359)Roads & Trails						
50	SUBTOTAL TRANSMISSION	330,178					
51	Distribution Plant						
52	(361)Structures and Improvements	4,125	65 years		5%	1.63%	60 years
53	(362)Station Equipment	73,476	65 years		20%	1.75%	54 years
54	(363.3) Communication Equipment	1,554	15 years			6.67%	5 years
55	(364)Poles, Towers & Fixtures	126,096	55 years		50%	3.24%	41 years
56	(365)Overhead Conductor	64,806	60 years		50%	2.16%	47 years
57	(366)Underground Conduit	31,196	65 years		40%	2.21%	52 years
58	(367)Underground Conductors and Devices	43,808	55 years		15%	1.67%	44 years
59	(368)Line Transformers	91,305	51 years			2.53%	38 years
60	(369)Services	30,824	50 years		100%	3.62%	36 years
61	(370)Meters	19,010	45 years		5%	11.65%	7 years
62	(371)Installation on Customer Premises	3,175	40 years		20%	2.23%	31 years
63	(373)Street Lighting	13,428	46 years		20%	1.78%	37 years
64	SUBTOTAL DISTRIBUTION	502,803					
65	General Plant						
66	(390)Structures and Improvements	10,315	60 years		10%	3.83%	15 years
67	(391)Office Furniture & Equipment	1,545	5 years			20%	2 years
68	(392)Transportation Equipment	26,276	15 years		10%	6.93%	11 years

69	(393)Stores Equipment	49	25 years		4%		6 years
70	(394)Tools, Shop. & Garage Equipment	3,826	25 years		4%		17 years
71	(395)Laboratory Equipuipment	1,397	25 years		4%		15 years
72	(396)Power Operated Equipment	5,612	19 years	10%	4.66%		11 years
73	(397)Communication Equipment	3,000	5 years		6.67%		5 years
74	(397.1) Computer Hardware	741	5 years		20%		2 years
75	(397.3) Communication Equipment	457	15 years		6.67%		5 years
76	(398)Miscellaneous Equipment	92	20 years		5%		11 years
77	SUBTOTAL GENERAL	53,310					
78	TOTAL	1,315,811					

Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
(1) An Original
(2) A Resubmission

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12/31/2025

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End of: 2025/ Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.
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.

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 (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)	EXPENSES INCURRED DURING YEAR			AMORTIZED DURING YEAR			
						CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
						Department (f)	Account No. (g)	Amount (h)				
1	FERC Assessment	181,433		181,433		Regulatory	928	181,433				
2	Colorado Public Utilities Commission Fees	975,549	8,435	983,984		Regulatory	928	983,984				
3	Rate Case Expenses		430,540	430,540		Regulatory	928	430,540	2,282,987		417,976	1,865,011
4	Electric Vehicle Transportation Electrification Program		107,318	107,318	96,088	Regulatory	928	107,318	(50,601)		23,899	21,588
46	TOTAL	1,156,982	546,293	1,703,275	96,088			1,703,275	2,232,386		441,875	1,886,599

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End of: 2025/ 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. Solar
 - f. Wind
 - g. Other renewable
 - h. Unconventional generation
 - i. Siting and heat rejection
 - 2. Transmission
 - 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		Unamortized Accumulation (g)
					Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	
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Name of Respondent:
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DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	656,336		656,336
4	Transmission	1,274,545		1,274,545
5	Regional Market			
5.1	Energy Storage			
6	Distribution	5,196,542		5,196,542
7	Customer Accounts	928,710		928,710
8	Customer Service and Informational	446,769		446,769
9	Sales	9,361		9,361
10	Administrative and General	12,190,383		12,190,383
11	TOTAL Operation (Enter Total of lines 3 thru 10)	20,702,646		20,702,646
12	Maintenance			
13	Production	682,100		682,100
14	Transmission	454,520		454,520
15	Regional Market			
15.1	Energy Storage			
16	Distribution	2,543,235		2,543,235
17	Administrative and General	35,337		35,337
18	TOTAL Maintenance (Total of lines 13 thru 17)	3,715,192		3,715,192
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	1,338,436		1,338,436
21	Transmission (Enter Total of lines 4 and 14)	1,729,065		1,729,065
22	Regional Market (Enter Total of Lines 5 and 15)			
22.1	Energy Storage (Enter Total of Lines 5.1 and 15.1)			
23	Distribution (Enter Total of lines 6 and 16)	7,739,777		7,739,777
24	Customer Accounts (Transcribe from line 7)	928,710		928,710
25	Customer Service and Informational (Transcribe from line 8)	446,769		446,769
26	Sales (Transcribe from line 9)	9,361		9,361
27	Administrative and General (Enter Total of lines 10 and 17)	12,225,720		12,225,720
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	24,417,838		24,417,838
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminating 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 Terminating 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 Terminating 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	(23,865)	223,269	199,404
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	24,393,973	223,269	24,617,242
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	4,651,949		4,651,949
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	4,651,949		4,651,949
72	Plant Removal (By Utility Departments)			
73	Electric Plant	42,242		42,242
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	42,242		42,242
77	Other Accounts (Specify, provide details in footnote):			
78	Stores Expenses Undistributed (163)	502,423		502,423
79	Clearing Accounts (184)	3,382,644		3,382,644
80				
81				
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93				
94				
95	TOTAL Other Accounts	3,885,067		3,885,067
96	TOTAL SALARIES AND WAGES	32,973,231	223,269	33,196,500

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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.

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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, Purchase 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)	1,011,667	1,323,495	2,321,588	3,071,653
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(1,729,636)	(3,342,099)	(5,317,734)	(7,767,391)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
46	TOTAL	(717,969)	(2,018,604)	(2,996,146)	(4,695,738)

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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.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
		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	3,554,000	KW/M	220,073	1,141,823	KW/M	269,724
2	Reactive Supply and Voltage				577,312	KW/M	81,957
3	Regulation and Frequency Response	7,191,398	KW/M	663,513			
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other			(42,487)			(73,658)
8	Total (Lines 1 thru 7)	10,745,398		841,099	1,719,135		278,023

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FOOTNOTE DATA

[\(a\)](#) Concept: AncillaryServicesPurchasedAmount

FERC Annual Charge Assessment, true ups, and current year adjustments

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: Colorado Electric									
1	January	316	20	19	299	17			1	96
2	February	307	11	18	292	15			1	175
3	March	280	20	8	266	13	3			103
4	Total for Quarter 1				857	45	3		2	374
5	April	264	4	21	252	11	3			103
6	May	287	23	19	276	11	3			63
7	June	390	20	19	375	13	3			339
8	Total for Quarter 2				903	35	9			505
9	July	414	9	19	399	14	3			186
10	August	410	6	17	396	14	3			126
11	September	343	4	18	330	11	3			55
12	Total for Quarter 3				1,125	39	9			367
13	October	286	3	18	277	10	3			13
14	November	283	30	18	268	14	3			55
15	December	298	4	18	283	14	3			133
16	Total for Quarter 4				828	38	9			201
17	Total				3,713	157	30		2	1,447

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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									

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)	1,754,156
3	Steam		23	Requirements Sales for Resale (See instruction 4, page 311.)	0
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	463,981
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	3,761
6.1	Solar		27	Total Energy Losses	116,552
6.2	Wind	215,288	27.1	Total Energy Stored	
6.3	Other Renewable		28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	2,338,450
7	Other	527,149			
8	Less Energy for Pumping				
9	Net Generation (Enter Total of lines 3 through 8)	742,437			
10	Purchases (other than for Energy Storage)	1,596,013			
10.1	Purchases for Energy Storage				
11	Power Exchanges:				
12	Received	3,009,282			
13	Delivered	3,009,282			
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received				
17	Delivered				
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)	2,338,450			

Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
(1) An Original
(2) A Resubmission

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ 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: Colorado Electric					
29	January	247,444	53,092	299	20	19
30	February	190,112	20,222	292	11	18
31	March	199,102	24,146	265	20	8
32	April	200,743	30,476	252	4	21
33	May	211,344	41,784	274	23	20
34	June	223,677	24,447	372	20	19
35	July	270,207	44,525	396	9	19
36	August	263,844	47,310	392	6	17
37	September	211,044	38,233	328	4	18
38	October	221,142	57,822	275	3	18
39	November	209,181	41,330	267	30	18
40	December	218,962	40,594	284	4	18
41	Total	2,666,802	463,981			

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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 Mcf.
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: Airport Diesel	Plant Name:	Plant Name: Pueblo Airport Generating Station- Unit 6	Plant Name:	Plant Name: Pueblo Airport Generation Station- Unit 1 & 2	Plant Name: Rocky Ford Diesels
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Internal Combustion		Gas Turbine		Gas Turbine	Internal Combustion
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional		Conventional		Conventional	Conventional
3	Year Originally Constructed	1964		2016		2012	1964
4	Year Last Unit was Installed	2001		2016		2012	1964
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	10		42		200	10
6	Net Peak Demand on Plant - MW (60 minutes)	10		40		180	10
7	Plant Hours Connected to Load	23		235		5,247	32
8	Net Continuous Plant Capability (Megawatts)	10		40		180	10
9	When Not Limited by Condenser Water						
10	When Limited by Condenser Water						
11	Average Number of Employees			2		9	
12	Net Generation, Exclusive of Plant Use - kWh	(309,115)		6,589,975		521,284,250	(267,630)
13	Cost of Plant: Land and Land Rights	93,354		28,551		6,330,770	12,618
14	Structures and Improvements	75,903				16,700,306	169,131
15	Equipment Costs	4,599,181		59,909,669		227,335,799	2,006,908
16	Asset Retirement Costs					2,841,360	1,112
17	Total Cost (10-23)						
18	Cost per KW of Installed Capacity (line 17/5) Including	476.844		1,427.100		1,266.041	218.977
19	Production Expenses: Oper, Supv, & Engr	6,934		2,497		329,224	6,852
20	Fuel	12,688		89,567		6,618,071	17,819
21	Coolants and Water (Nuclear Plants Only)						
22	Steam Expenses						
23	Steam From Other Sources						
24	Steam Transferred (Cr)						
25	Electric Expenses	314		251,923		1,138,929	1,112
26	Misc Steam (or Nuclear) Power Expenses						
27	Rents					2,421	
28	Allowances						
29	Maintenance Supervision and Engineering					48,042	
30	Maintenance of Structures	20,436				1,620	12,422
31	Maintenance of Boiler (or reactor) Plant						
32	Maintenance of Electric Plant	134,500		290,814		3,560,216	22,483
33	Maintenance of Misc Steam (or Nuclear) Plant						
34	Total Production Expenses	174,872		634,801		11,698,523	60,688
35	Expenses per Net kWh			0.0963		0.0224	
35	Plant Name	Airport Diesel				Rocky Ford Diesels	
36	Fuel Kind	Oil	Natural Gas	Natural Gas		Oil	
37	Fuel Unit	Bbl	Mcf	Mcf		Bbl	
38	Quantity (Units) of Fuel Burned		151	67,137	5,218,378		145
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)		137,352	1,087	1,087		138,675
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year		84.30	1.33	1.27		122.77
41	Average Cost of Fuel per Unit Burned		84.30	1.33	1.27		122.77
42	Average Cost of Fuel Burned per Million BTU		14.61	1.23	1.17		21.08

43	Average Cost of Fuel Burned per kWh Net Gen		0.014	0.013	
44	Average BTU per kWh Net Generation		11,074	10,882	

Name of Respondent:
Black Hills Colorado Electric, LLC

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End of: 2025/ 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 (10-23)					
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					

Name of Respondent:
Black Hills Colorado Electric, LLC

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12/31/2025

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End of: 2025/ 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 Demand 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 (10-23)				
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))				

Name of Respondent:
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End of: 2025/ 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, pumped storage plants, and renewable plants of less than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, renewable, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
4. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

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)	Fuel Costs (in cents (per Million Btu) (l))	Generation Type (m)
									Fuel Production Expenses (i)	Maintenance Production Expenses (j)			
1	^(a) Pueblo Diesels	1964	8	8	(201,875)	1,824,226	(90.36)	6,838	7,528	81,292	Oil	18.02	Other

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FOOTNOTE DATA

[\(a\)](#) Concept: PlantName

These were retired in December of 2025.

ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) and (b) report the name of the energy storage project and location.
3. In column (c), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In column (d) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (c) should include MWHs delivered/provided to a generator's own load requirements or used for the provision of ancillary services.
5. In column (e) report MWHs lost during conversion, storage and discharge of energy.
6. In column (f) report the MWHs sold.
7. In column (g), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the income generating activity.
8. In column (h), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined. In columns (i) and (j), report fuel costs for storage operations associated with self-generated power and other costs associated with self-generated power.
9. In column (l) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy storage equipment, turbines, compressors, generators, switching and conversion equipment, lines and equipment whose primary 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 property accounts listed.

Line No.	Name of the Energy Storage Project (a)	Location of the Project (b)	MWHs (c)	MWHs delivered to the grid (d)	MWHs Lost During Conversion, Storage and Discharge of Energy (e)	MWHs Sold (f)	Revenues from Energy Storage Operations (g)	Power Purchased for Storage Operations (555.1) (Dollars) (h)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (i)	Other Costs Associated with Self-Generated Power (Dollars) (j)	Account for Project Costs (k)	Total Project Plant Costs (l)
1												
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31												
32												
33												
34												
35	TOTAL											

ENERGY STORAGE OPERATIONS (Small Plants)

1. Small Plants are plants less than 10,000 Kw.
2. In columns (a) and (b) report the name of the energy storage project, and location.
3. In column (c), report project plant cost including but not exclusive of land and land rights, structures and improvements, energy storage equipment and any other costs associated with the energy storage project.
4. In column (d), report operation expenses excluding fuel, (e), maintenance expenses, (f) fuel costs for storage operations and (g) cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined.
5. If any other expenses, report in column (h) and footnote the nature of the item(s).

Line No.	Name of the Energy Storage Project (a)	Location of the Project (b)	Project Cost (c)	Plant Operating Expenses				
				Operations (Excluding Fuel used in Storage Operations) (d)	Maintenance (e)	Cost of fuel used in storage operations (f)	Account No. 555.1, Power Purchased for Storage Operations (g)	Other Expenses (h)
1								
2								
3								
4								
5								
6								
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31								
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33								
34								
35								
36	TOTAL							

Name of Respondent:
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TRANSMISSION LINE STATISTICS

- Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
- Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
- Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
- Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
- Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.
- Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).
- Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
- Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
- 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)			Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line	Number of Circuits		Land	Construction Costs	Total Costs	Operation Expenses	Maintenance Expenses	Rents	Total Expenses
	(a)	(b)	(c)	(d)		(f)	(g)	(h)		(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	Hogback	N Penrose	115.00	115.00	H-Wood/SP-Steel	16.70			795 ACSR Drake	1,769,662	20,004,710	21,774,372				
2	PSCO Junct #234	Canon West	115.00	115.00	H-Wood	23.78		1	477 26/7 ACSR		468,586	468,586				
3	Canon City	Hogback	115.00	115.00	H-Wood	3.76		1	795 26/7 ACSR	10,804	3,464,499	3,475,303				
4	Hogback	Canon West	115.00	115.00	H-Wood	3.88		1	795 ACSR		4,493,885	4,493,885				
5	Skala Tap	Skala Sub	115.00	115.00	SP-Steel	0.66		2	795 26/7 ACSR	31,267	3,637,098	3,668,365				
6	Canon City	Skala Tap	115.00	115.00	H-Wood	9.87		1	795 26/7 ACSR	19,343	7,671,808	7,691,151				
7	Skala Tap	Portland	115.00	115.00	H-Wood	3.45		1	795 26/7 ACSR							
8	Pueblo Plant	Hyde Park	115.00	115.00	SP-Wood	2.45		1	795 26/7 ACSR	4,846	2,921,690	2,926,536				
9	Hyde Park	West Station	115.00	115.00	H-Wood	2.05		1	795 26/7 ACSR							
10	West Station	Xcel Tap	115.00	115.00	H-Wood	2.50		1	336 30/7 ACSR	1,487	99,564	101,051				
11	Northridge	PSCO Tap #1	115.00	115.00	SP-Steel	1.95		1	795 26/7 ACSR		72,786	72,786				
12	Baculite Mesa	Fountain Lake	115.00	115.00	SP-Steel	4.90		1	795 26/7 ACSR	172,744	10,792,772	10,965,516				
13	Fountain Lake	Northridge	115.00	115.00	SP-Steel	2.60		1	795 26/7 ACSR							
14	Baculite Mesa	West Station	115.00	230.00	SP-Steel	11.52		2	1272 45/7 ACSR							
15	Baculite Mesa	Airport Industrial	115.00	115.00	SP-Wood	2.66		1	795 26/7 ACSR		59,611	59,611				
16	Nyberg	LaJunta	115.00	115.00	H-Wood/SP-Steel	56.15		1	795 ACSR	163,497	19,459,930	19,623,427				
17	Airport Memorial	Nyberg	115.00	115.00	SP-Wood	4.80		1	795 26/7 ACSR	48,361	2,096,056	2,144,417				
18	Baculite Mesa	Nyberg	115.00	115.00	SP-Steel	7.27		2	1272 45/7 ACSR		7,371,282	7,371,282				
19	Portland Sub	West Station N	115.00	115.00	H-Wood	20.00		1	795 26/7 ACSR		8,791,278	8,791,278				
20	DOT Tap	DOT	115.00	115.00	H-Wood	11.75		1	336 30/7 ACSR		14,127	14,127				
21	DOT Tap	PDA	115.00	115.00	H-Wood	1.50		1	477 ACSR	800	2,707	3,507				
22	Portland Sub	West Station	115.00	115.00	H-Wood	20.00		1	336 30/7 ACSR	2,754	1,357,929	1,360,683				
23	West Station	Pueblo West	115.00	115.00	SP-Steel	4.70		1	795 ACSR	3,078,796	20,852,657	23,931,453				
24	North Penrose	Pueblo West	115.00	115.00	SP-Steel	25.60		1	795 ACSR		4,880,322	4,880,322				
25	Burnt Mill	Greenhorn	115.00	115.00	H-Wood/SP-Wood	4.18		1	795 26/7 ACSR	53,044	1,222,882	1,275,926				
26	Greenhorn	Reader	115.00	115.00	SP-Steel	4.15		2	795 26/7 ACSR							
27	Burnt Mill	Pueblo Reservoir	115.00	115.00	H-Wood	5.85		1	795 26/7 ACSR	43,019	2,180,272	2,223,291				
28	West Station #1	Pueblo Reservoir	115.00	115.00	H-Wood	2.96		1	795 26/7 ACSR	1,100	2,122,601	2,123,701				
29	Pueblo Plant	Reader	115.00	115.00	SP-Wood/H-Wood	5.55		1	795 AAC / 795 ACSR	32,079	846,161	878,240				

30	PSCO Tap	West Station	115.00	115.00	H-Wood	2.61		1	336 30/7 ACSR		542,119	542,119			
31	Desert Cove	Fountain Valley	115.00	115.00	SP-Steel	5.07		2	795 26/7 ACSR		2,951,140	2,951,140			
32	Desert Cove	West Station	115.00	115.00	SP-Steel	4.00		2	795 26/7 ACSR		3,443,776	3,443,776			
33	Fountain Valley	Midway	115.00	115.00	H-Wood	9.71		1	795 26/7 ACSR		2,141,655	2,141,655			
34	Canon West	Arequa Gulch	115.00	115.00	SP-Wood	21.91		1	266 26/7 ACSR	172,704	13,574,549	13,747,253			
35	Airport Memorial	Reader	115.00	115.00	SP-Wood	11.82		1	795 26/7 ACSR	235,304	3,320,261	3,555,565			
36	Reader	Rattle Snake Butte	115.00	115.00	SP-Wood/H- Wood	35.12		1	795 26/7 ACSR	180,994	16,383,385	16,564,379			
37	Rattle Snake Butte	Peak View	115.00	115.00	H-Wood	9.08		1	795 26/7 ACSR	832,499	4,140,690	4,973,189			
38	Airport Industrial	Airport Memorial (700)	115.00	115.00	SP-Wood/H- Wood	2.97		1	336.4 ACSR		61,939	61,939			
39	Boone	Fowler	115.00	115.00	SP-Steel	18.83		1	795 ACSR	56,668	11,791,998	11,848,666			
40	Portland	Holcim	115.00	115.00	SP-Wood	1.07		1	336.4 ACSR		1,829	1,829			
36	TOTAL					389.38		45		6,911,772	183,238,554	190,150,326			

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under-ground construction and show each transmission line separately. If actual costs of completed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	LINE COST					Construction
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing		Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
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44	TOTAL																

Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
(1) An Original
(2) A Resubmission

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ Q4

SUBSTATIONS

- Report below the information called for concerning substations of the respondent as of the end of the year.
- Substations which serve only one industrial or street railway customer should not be listed below.
- Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
- Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
- Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
- Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

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)	Conversion Apparatus and Special Equipment		
		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)	Number of Units (j)	Total Capacity (In MVA) (k)
1	Airport Industrial Park Pueblo, CO	Distribution	Unattended	115	13.80		47	2		LTC Fans		47
2	Airport Memorial Pueblo, CO	Distribution	Unattended	115	13.80		34	1		LTC Fans		34
3	Arequa Gulch/Trans Victor, CO	Transmission	Unattended	115	69.00		30	1		LTC Fans		30
4	Arequa Gulch/Dist Victor, CO	Distribution	Unattended	115	13.80		60	2		LTC Fans		60
5	Belmont Pueblo, CO	Distribution	Unattended	69	13.80		20	2		LTC Fans		20
6	Blende Pueblo, CO	Distribution	Unattended	69	13.80		21	2		LTC Fans		21
7	Boone Boone, CO	Transmission	Unattended	115	69.00	13.2	50	1		LTC Fans		50
8	Burnt Mill/Dist Pueblo, CO	Distribution	Unattended	115	13.80		25	1		LTC Fans		25
9	Busch Ranch 2 Walsenburg, CO	Transmission	Unattended	115	34.50	13.8	70	1		Fans		70
10	Canon City Canon City, CO	Transmission	Unattended	115	69.00	2.4	56	1		LTC Fans		56
11	Canon City 13.8KV Canon City, CO	Distribution	Unattended	115	13.80		22	1		LTC Fans		22
12	Canon City 25KV Canon City, CO	Distribution	Unattended	13.8	25.00		2	1				2
13	Canon West Canon City, CO	Transmission	Unattended	230	115.00	13.8	150	1	1	Fans		150
14	Canon West Canon City, CO	Distribution	Unattended	115	25.00		14	1		LTC Fans		14
15	Cripple Creek Cripple Creek, CO	Distribution	Unattended	69	13.80		21	2		LTC Fans		21
16	Desert Cove/Dist Pueblo West, CO	Distribution	Unattended	115	13.80		45	2		LTC Fans		45
17	East Canon Canon City, CO	Distribution	Unattended	69	13.80		35	2		LTC Fans		35
18	Erie Avenue Pueblo, CO	Distribution	Unattended	69	13.80		56	1		LTC Fans		56
19	Fountain Lake/Trans Pueblo, CO	Transmission	Unattended	115	69.00		83	1		LTC Fans		83
20	Fountain Lake/Dist Pueblo, CO	Distribution	Unattended	115	13.80		25	1		LTC Fans		25
21	Florence Florence, CO	Distribution	Unattended	69	13.80		9	1		LTC Fans		9
22	Fowler Fowler, CO	Distribution	Unattended	69	13.80		14	1		LTC Fans		14
23	Freemary Pueblo, CO	Distribution	Unattended	69	13.80		20	2		LTC Fans		20
24	Greenhorn/Dist Pueblo, CO	Distribution	Unattended	115	13.80		55	2		LTC Fans		55
25	Hogback Canon City, CO	Transmission	Unattended	115	69.00	13.2	93	1		LTC Fans		93
26	Huerfano Pueblo, CO	Distribution	Unattended	69	13.80		11	1		Reg Fans		11
27	Hyde Park/Dist Pueblo, CO	Distribution	Unattended	115	13.80		25	1		LTC Fans		25
28	LaJunta/Trans La Junta, CO	Transmission	Unattended	115	69.00	2.4	25	1		Reg Fans		25
29	LaJunta/Dist La Junta, CO	Distribution	Unattended	69	13.80		5	1		LTC Fans		5
30	Manzanola Manzanola, CO	Distribution	Unattended	69	13.80		10	1		Reg Fans		10
31	Miscellaneous Subs	Distribution	Unattended				75	26	5			75
32	Mobile Substations	Distribution	Unattended	115	25.00		31	3				31
33	North Canon Canon City, CO	Distribution	Unattended	69	13.80		10	1		Reg Fans		10
34	North Penrose/Dist Penrose, CO	Distribution	Unattended	115	13.80		56	1		LTC Fans		56
35	Northridge Pueblo, CO	Distribution	Unattended	115	13.80		44	2		LTC Fans		44
36	Oak Creek Westcliffe, CO	Distribution	Unattended	69	24.90		3	1		Reg		3
37	Ordway Ordway, CO	Distribution	Unattended	69	13.80		10	1		Reg Fans		10
38	Overton Pueblo, CO	Distribution	Unattended	69	13.80		10	1		LTC Fans		10
39	PDA Avondale, CO	Distribution	Unattended	115	13.80		40	2		LTC Fans		40
40	Peakview Walsenburg, CO	Transmission	Unattended	115	34.50	13.8	70	1				70
41	Penrose Penrose, CO	Distribution	Unattended	69	13.80		20	1		LTC Fans		20
42	Portland Florence, CO	Transmission	Unattended	115	69.00	2.4	140	2		LTC Fans		140
43	Prairie Avenue Pueblo, CO	Distribution	Unattended	69	13.80		36	2		LTC Fans		36
44	Pueblo/Dist Pueblo, CO	Distribution	Unattended	115	13.80		56	2		LTC Fans		56

45	Pueblo Reservoir/Dist Pueblo, CO	Distribution	Unattended	115	13.80		25	1		LTC Fans	25
46	Pueblo West/Dist Pueblo West, CO	Distribution	Unattended	115	13.80		56	1		LTC Fans	56
47	Rattlesnake Butte Walsenburg, CO	Transmission	Unattended	115	34.50	13.8	40	1			40
48	Reader Pueblo, CO	Transmission	Unattended	115	69.00	2.4	166	2		LTC Fans	166
49	Rocky Ford Rocky Ford, CO	Distribution	Unattended	69	13.80		10	1		Reg	10
50	Skala Florence, CO	Distribution	Unattended	115	13.80		22	1		LTC Fans	22
51	Skinner Westcliffe, CO	Distribution	Unattended	69	13.80		7	1		Reg	7
52	South Canon Canon City, CO	Distribution	Unattended	69	13.80		10	1		LTC Fans	10
53	South Fowler Fowler, CO	Transmission	Unattended	115	69.00	13.2	93	1		LTC Fans	93
54	St Charles Pueblo, CO	Distribution	Unattended	69	13.80		25	1		LTC Fans	25
55	Stonemoor Pueblo, CO	Distribution	Unattended	69	13.80		21	2		LTC Fans	21
56	Sunset Pueblo, CO	Distribution	Unattended	69	13.80		21	2		LTC Fans	21
57	Victor Victor, CO	Distribution	Unattended	69	24.90		7	1		Reg	7
58	West Station Pueblo, CO	Transmission	Unattended	115	69.00	2.4	83	2		LTC Fans	83
59	Fountain Valley Pueblo West, CO	Distribution	Unattended	115	2.40		5	1		LTC	5
61	Total			5,580	1,560	107	2,325	104	6		2,325

Name of Respondent:
Black Hills Colorado Electric, LLC

This report is:
(1) An Original
(2) A Resubmission

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ 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	^(b) Allocation of direct and indirect costs provided by BHSC	^(b) Black Hills Service Company	^(b) Various	46,623,560
19				
20	Non-power Goods or Services Provided for Affiliated			
21	Revenue under shared services agreement	^(b) Black Hills Colorado IPP	454	1,280,085
22	^(b) Allocation of costs of Busch Ranch I Wind Farm	^(b) Black Hills Electric Generation	^(b) Various	439,308
42				

FOOTNOTE DATA

(a) Concept: DescriptionOfNonPowerGoodOrService

The below table provides the breakdown for the Allocation of direct and indirect costs provided by BHSC:

	Indirect	Direct	Combined
Operating Revenues (400)	-	(150,177)	(150,177)
Operation Expenses (401)	27,628,717	5,825,949	33,454,666
Maintenance Expenses (402)	2,712,769	4,845,285	7,558,054
Depreciation Expense (403)	3,440,619	-	3,440,619
Amort. & Depl of Utility Plant (404-405)	469,512	-	469,512
Taxes Other Than Income Taxes (408.1)	919,914	186,799	1,106,713
Revenues From Merchandising, Jobbing and Contract Work (415)	(42,415)	-	(42,415)
Costs and Exp. Of Merchandising, Job. & Contract Work (416)	26,048	69,121	95,169
Expenses of Nonutility Operations (417.1)	8,310	-	8,310
Miscellaneous Nonoperating Income (421)	(40,493)	(5,000)	(45,493)
Donations (426.1)	49,574	29,079	78,653
Exp. For Certain Civic, Political & Related Activities (426.4)	62,400	232,325	294,725
Other Deductions (426.5)	293,976	59,222	353,198
Taxes Other Than Income Taxes (408.2)	1,461	565	2,026
	35,530,392	11,093,168	46,623,560
Schedule 429 Total			46,623,560
Revenues	(82,908)	(155,177)	(238,085)
Expenses	35,613,300	11,248,345	46,861,645
	35,530,392	11,093,168	46,623,560

(b) Concept: NameOfAssociatedAffiliatedCompany

Colorado Electric has a service agreement with BHSC, whereby BHSC charges us, at cost, for various direct and indirect services provided to us. Pursuant to the BHSC Cost Allocation Manual, indirect service cost allocations are determined in accordance with the Public Utility Holding Company Act of 2005.

(c) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

The below table provides the breakdown for the Allocation of direct and indirect costs provided by BHSC:

		Indirect	Direct	Combined
Customer Service	Customer Service	1,647,297	974,255	2,621,552
Generation Support	Generation Support	29,508	1,220,887	1,250,395
Transmission	Transmission	4,399,151	5,892,545	10,291,696
Generation Dispatch and Power Marketing	Generation Dispatch and Power Marketing	1,456,662	-	1,456,662
General Accounting	General Accounting	1,679,656	309,721	1,989,377
Executive Management	Executive Management	1,101,926	951	1,102,877
NERC Compliance	NERC Compliance	135,898	-	135,898
Regulatory & Governmental Affairs	Regulatory & Governmental Affairs	916,038	1,892,994	2,809,032
Environmental Services	Environmental Services	74,181	108,845	183,026
Finance & Treasury	Finance & Treasury	747,943	30,256	778,199
Information Technology	Information Technology	7,801,545	504,023	8,305,568
Safety	Safety	131,025	3,275	134,300
Power Delivery Management	Power Delivery Management	519,632	22,012	541,644
Human Resources	Human Resources	809,568	88,675	898,243
Communications	Communications	327,074	54,955	382,029
Generation Plant Operations	Generation Plant Operations	14,732	938,572	953,304
Corporate Development	Corporate Development	694,318	72,506	766,824
Credit & Risk	Credit & Risk	3,127	-	3,127
Organizational Development & Training	Organizational Development & Training	58,532	-	58,532
Internal Audit	Internal Audit	297,404	-	297,404
Supply Chain Management	Supply Chain Management	726,958	73,688	800,646
Legal	Legal	3,468,034	3,101,377	6,569,411
Tax	Tax	394,658	5,011	399,669
Marketing & External Affairs	Marketing & External Affairs	139,347	319,069	458,416
Other Miscellaneous	Other Miscellaneous	7,956,178	(4,520,449)	3,435,728
		35,530,392	11,093,168	46,623,560

(d) Concept: DescriptionOfNonPowerGoodOrService

The below table presents the breakdown of Corriedale allocations to Cheyenne Light, Fuel, and Power:

	Corriedale Alloc to CLFP
Generation Support	30,866
Transmission	156
General Accounting	20
Environmental Services	235
Power Delivery Management	485
Generation Plant Operations	508
Legal	51,022
	439,308

(e) Concept: NameOfAssociatedAffiliatedCompany

We have a shared services agreement with Black Hills Colorado IPP. Black Hills Colorado IPP assets are located at the Pueblo Airport Generating Station ("PAGS") site, with generation assets owned by us. We have entered into a facility agreement with Black Hills Colorado IPP that allows shared utilization of certain utility assets for a facility fee. The facility fee charge is based on the cost of the associated assets, along with the related operating expenses, and allocated between us and Black Hills Colorado IPP based on generation asset nameplate rating owned by each party at the PAGS site.

(f) Concept: NameOfAssociatedAffiliatedCompany

Colorado Electric owns 50% of Busch Ranch I, a 29 MW wind farm near Pueblo, Colorado, while Black Hills Electric Generation owns the remaining 50% ownership interest. Each company is obligated to make payments for costs associated with their proportionate share of the costs of operating the wind farm over the life of the facility. Colorado Electric retains responsibility for operations of the wind farm. Black Hills Electric Generation provides its share of energy from the wind farm to Colorado Electric through a PPA, which expires in October 2037.

(g) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

The below table presents the breakdown of accounts for the Corriedale allocation to Cheyenne Light, Fuel, and Power:

	Corriedale Alloc to CLFP
Operation Expenses (401)	437,141
Taxes Other Than Income Taxes (408.1)	1,715
	439,308
Schedule 429 Total	439,308
Revenues	-
Expenses	439,308
	439,308