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

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

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
Avista Corporation	End of: 2023/ Q4

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

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

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

c. Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426

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

   The CPA Certification Statement should:

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

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

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

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

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

   Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

f. Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

g. Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/general-information-0/electric-industry-forms.

IV. When to Submit

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

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

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

V. Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

VII. For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

3. 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;
4. 'Person' means an individual or a corporation;
5. 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;
7. 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......
11. "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

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

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

"Sec. 304.

a. Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may 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 field..."

GENERAL PENALTIES

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent Avista Corporation	02 Year/ Period of Report End of: 2023/ 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)

1411 East Mission Avenue, Spokane, WA 99207

05 Name of Contact Person Ryan L. Krasselt	06 Title of Contact Person VP, Controller, Prin. Acctg Officer

07 Address of Contact Person (Street, City, State, Zip Code)

1411 East Mission Avenue, Spokane, WA 99207

08 Telephone of Contact Person, Including Area Code (509) 495-2273	09 This Report is An Original / A Resubmission (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 04/12/2024

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 Ryan L. Krasselt	03 Signature Ryan L. Krasselt	04 Date Signed (Mo, Da, Yr) 04/12/2024
02 Title VP, Controller, Prin. Acctg Officer		

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

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

LIST OF SCHEDULES (Electric Utility)

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Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	
61	Electric Energy Account	401a	
62	Monthly Peaks and Output	401b	
63	Steam Electric Generating Plant Statistics	402	
64	Hydroelectric Generating Plant Statistics	406	
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)		
	Stockholders' Reports Check appropriate box: ☐ Two copies will be submitted ☐ No annual report to stockholders is prepared		

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ 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.

Avista Corporation

Ryan L. Krasselt

VP, Controller, Prin Acctg Officer

1411 E. Mission Avenue, Spokane, WA 99207

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 Washington, Incorporated March 15, 1889

State of Incorporation: WA

Date of Incorporation: 1889-03-15

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: None

(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 in the states of Washington, Idaho, and Montana Natural gas service in the states of Washington, Idaho, and Oregon

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: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

CORPORATIONS CONTROLLED BY RESPONDENT

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Avista Capital, Inc.	Parent to the Co's Subsidiary	100%	1
2	Avista Development, Inc.	Investment in Real Estate	100%	2
3	Avista Edge, Inc.	Investment in Internet Tech.	100%	3
4	Pentzer Corporation	Parent of Pentzer Venture Holdings	100%	4
5	Pentzer Venture Holdings II, Inc.	Holding Company-Inactive	100%	5
6	University Development Company, LLC	Facilitates Property Acquisitions	100%	6
7	Avista Capital II	Affiliated business trust issued preferred trust Securities	100%	7
8	Avista Northwest Resources, LLC	Owns an interest in a venture fund investment	100%	8
9	Courtyard Office Center, LLC	Inactive	100%	9
10	Salix, Inc.	Liquified Natural Gas Operations	100%	10
11	Alaska Energy and Resources Company (AERC)	Parent Co of Alaska Opertions	100%	11
12	Alaska Electric Light and Power Company	Utility Operations in Juneau	100%	12
13	AJT Mining Properties, Inc.	Inactive mining Co holding certain properties	100%	13
14	Snettisham Electric Company	Right to Purchase Snettisham	100%	14

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

OFFICERS

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)	Date Started in Period (d)	Date Ended in Period (e)
1	Chief Executive Officer	D. P. Vermillion	868,569	2023-01-01	2023-12-31
2	President and Chief Operating Officer	H. L. Rosentrater	424,279	2023-10-01	2023-12-31
3	Executive Vice President	M. T. Thies	264,568	2023-05-11	2023-10-01
4	Senior Vice President, Chief Financial Officer, Treasurer and Regulatory Affairs Officer	K. J. Christie	382,338	2023-05-11	2023-12-31
5	Senior Vice President, Chief Strategy and Clean Energy Officer	J. R. Thackston	384,928	2023-01-01	2023-12-31
6	Senior Vice President, General Council, Corporate Secretary and Chief Ethics/ Compliance Officer	G. C. Hesler	400,719	2023-01-01	2023-12-31
7	Senior Vice President, Safety and Chief People Officer	B. A. Cox	351,862	2023-01-01	2023-12-31
8	Vice President Community Affairs and Chief Customer Officer	L. D. Hill	308,281	2023-01-01	2023-12-31
9	Vice President, Chief Information Officer, and Chief Security Officer	J. M. Kensok	204,423	2023-01-01	2023-08-01
10	Vice President, Controller, and Principal Accounting Officer	R. L. Krasselt	271,959	2023-01-01	2023-12-31
11	Vice President and Chief Counsel for Regulatory and Governmental Affairs	D. J. Meyer	326,254	2023-01-01	2023-12-31
12	Vice President, Energy Resources	S.J. Kinney	284,654	2023-01-01	2023-12-31
13	Vice President, Energy Delivery	J.D. DiLuciano	249,749	2023-01-01	2023-12-31
14	Vice President, Chief Information Officer, and Chief Security Officer	W.O. Manuel	193,847	2023-06-01	2023-12-31

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

DIRECTORS

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	Scott L. Morris (Chairman of the Board)	1411 E. Mission Ave, Spokane, WA 99202	true	true
2	Dennis P. Vermillion (CEO)	1411 E. Mission Ave, Spokane, WA 99202	true	false
3	Kristianne Blake	P.O. Box 3727, Spokane, WA 99220	true	false
4	Donald C. Burke	16 Ivy Court, Langhorne, PA 19047	false	false
5	Scott H. Maw	115 NW 78th St., Seattle, WA 98117	false	false
6	Rebecca A. Klein	611 S. Congress Ave., Suite 125, Austin, TX 78704	false	false
7	Jeffry L. Philipps	P.O. Box 9000, Spokane, WA 99209	false	false
8	Heidi B. Stanley	P.O. Box 2884, Spokane, WA 99220	true	false
9	Janet D. Widmann	26 Sanford Ln., Lafayette, CA 94549	false	false
10	Julie A. Bentz	38748 Lulay Rd, Scio, OR 97374	false	false
11	Sena M. Kwawu	2507 101st Lane NE, Bellevue, WA 98004	false	false
12	Kevin B. Jacobsen	1221 Broadway, Oakland, CA 94607	false	false

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IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

1. None

2. None

3. None

4. None

5. None

6. Reference is made to Notes 10, 11, and 12 of the Notes to Financial Statements.

7. None

8. Average annual wage increases were 5.4% for non-exempt employees effective February 27, 2023. Average annual wage increases were 5.8% for exempt employees effective February 27, 2023. Officers received average increases of 6.4% effective February 13, 2023. Certain bargaining unit employees received average increases of 3.5% effective March 26, 2023 and April 1, 2023.

9. Reference is made to Note 15 of the Notes to Financial Statements.

10. None

12. See page 123 of this report.

13. Effective May 11th, 2023, Kristianne Blake retired from the Company's Board of Directors. On May 11th, 2023, Kevin Jacobson was elected to the Board of Directors.

On May 1, 2023, Mark Thies, Executive Vice President, Chief Financial Officer, and Treasurer, announced to the Company's board of directors that he would retire, effective October 1, 2023. Following the announcement, the Company's board of directors appointed Kevin Christie as Chief Financial Officer, Treasurer, and Senior Vice President of Regulatory Affairs, effective May 11, 2023. Mr. Thies continued to serve as Executive Vice President until his retirement date.

Effective May 11, 2023, Latisha Hill added corporate communications, customer service and energy efficiency to her previous responsibilities. Her new title is Vice President of Community Affairs and Chief Customer Officer.

Effective June 1, 2023, Wayne Manuel joined the Company as Vice President, Chief Information Officer and Chief Security Officer. This role was previously held by Jim Kensok, who retired from the Company effective August 1, 2023.

Effective October 1, 2023, Senior Vice President and COO Heather Rosentrater became President and COO of the Company. Also effective October 1, 2023, Vice President, Safety and Chief People Officer Bryan Cox became Senior Vice President, Safety and Chief People Officer.

14. Proprietary capital is not less than 30 percent.

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ 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	7,852,959,203	7,477,186,308
3	Construction Work in Progress (107)	200	170,812,964	155,475,677
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		8,023,772,167	7,632,661,985
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	2,796,332,034	2,624,302,472
6	Net Utility Plant (Enter Total of line 4 less 5)		5,227,440,133	5,008,359,513
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)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		5,227,440,133	5,008,359,513
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)		6,992,076	6,992,076
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		22,796,933	11,036,947
19	(Less) Accum. Prov. for Depr. and Amort. (122)		110,345	103,609
20	Investments in Associated Companies (123)		11,547,000	11,547,000
21	Investment in Subsidiary Companies (123.1)	224	265,210,641	260,760,970
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		14,094	73,448
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		15,335,490	11,797,054
29	Special Funds (Non Major Only) (129)		0	0

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)
30	Long-Term Portion of Derivative Assets (175)		0	2,944,915
31	Long-Term Portion of Derivative Assets - Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		314,793,813	298,056,725
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		11,843,507	4,465,295
36	Special Deposits (132-134)		0	66,141,689
37	Working Fund (135)		758,362	776,205
38	Temporary Cash Investments (136)		15,991,036	496,573
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		199,763,204	219,394,599
41	Other Accounts Receivable (143)		38,651,095	67,155,969
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		4,905,146	6,345,841
43	Notes Receivable from Associated Companies (145)		20,584,744	9,364,617
44	Accounts Receivable from Assoc. Companies (146)		978,859	787,177
45	Fuel Stock (151)	227	4,683,150	4,252,607
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	79,492,528	73,453,924
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202/227	0	0
52	Allowances (158.1 and 158.2)	228	30,071,678	0
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		16,271,620	26,788,027
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		50,221,552	28,311,482
58	Advances for Gas (166-167)		0	0

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)
59	Interest and Dividends Receivable (171)		2,627,341	621,880
60	Rents Receivable (172)		7,380,742	4,556,651
61	Accrued Utility Revenues (173)		0	0
62	Miscellaneous Current and Accrued Assets (174)		0	230,226
63	Derivative Instrument Assets (175)		11,821,033	21,142,955
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	2,944,915
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		486,235,305	518,649,120
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		21,586,301	20,719,467
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	898,192,107	912,434,228
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	0
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		858,506	872,806
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	87,517,904	68,920,168
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352	0	0
81	Unamortized Loss on Reaquired Debt (189)		5,701,051	6,177,054
82	Accumulated Deferred Income Taxes (190)	234	214,152,188	269,470,612
83	Unrecovered Purchased Gas Costs (191)		51,370,535	52,091,145
84	Total Deferred Debits (lines 69 through 83)		1,279,378,592	1,330,685,480
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		7,314,839,919	7,162,742,914

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ 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	1,596,986,047	1,481,787,168
3	Preferred Stock Issued (204)	250	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	(2,732,405)	(10,696,711)
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	(50,073,294)	(54,094,483)
11	Retained Earnings (215, 215.1, 216)	118	798,215,179	772,567,765
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	43,138,900	38,974,396
13	(Less) Reacquired Capital Stock (217)	250	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(357,109)	(2,058,225)
16	Total Proprietary Capital (lines 2 through 15)		2,485,323,906	2,334,668,876
17	LONG-TERM DEBT			
18	Bonds (221)	256	2,543,700,000	2,307,200,000
19	(Less) Reacquired Bonds (222)	256	83,700,000	83,700,000
20	Advances from Associated Companies (223)	256	51,547,000	51,547,000
21	Other Long-Term Debt (224)	256	0	0
22	Unamortized Premium on Long-Term Debt (225)		106,600	115,483
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		795,576	841,286
24	Total Long-Term Debt (lines 18 through 23)		2,510,858,024	2,274,321,197
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		63,558,661	64,284,097
27	Accumulated Provision for Property Insurance (228.1)		0	0

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)
28	Accumulated Provision for Injuries and Damages (228.2)		995,000	1,320,000
29	Accumulated Provision for Pensions and Benefits (228.3)		89,829,937	93,900,990
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		618,329	774,805
32	Long-Term Portion of Derivative Instrument Liabilities		17,902,180	7,891,963
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		18,058,399	15,783,066
35	Total Other Noncurrent Liabilities (lines 26 through 34)		190,962,506	183,954,921
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		349,000,000	463,000,000
38	Accounts Payable (232)		136,101,468	195,759,919
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		0	114
41	Customer Deposits (235)		11,208,693	6,929,872
42	Taxes Accrued (236)	262	31,879,207	38,520,487
43	Interest Accrued (237)		22,318,892	19,663,017
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		40,534	202,211
48	Miscellaneous Current and Accrued Liabilities (242)		99,744,896	84,650,630
49	Obligations Under Capital Leases-Current (243)		4,490,212	4,348,776
50	Derivative Instrument Liabilities (244)		35,118,959	34,802,627
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		17,902,180	7,891,963
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		672,000,681	839,985,690

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)
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		4,436,513	4,211,506
57	Accumulated Deferred Investment Tax Credits (255)	266	28,233,162	28,784,445
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	32,918,243	48,402,602
60	Other Regulatory Liabilities (254)	278	479,233,915	525,409,545
61	Unamortized Gain on Reacquired Debt (257)		942,384	1,059,748
62	Accum. Deferred Income Taxes-Accel. Amort. (281)	272	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		653,219,870	636,821,685
64	Accum. Deferred Income Taxes-Other (283)		256,710,715	285,122,699
65	Total Deferred Credits (lines 56 through 64)		1,455,694,802	1,529,812,230
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		7,314,839,919	7,162,742,914

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

STATEMENT OF INCOME

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)
1	UTILITY OPERATING INCOME							
2	Operating Revenues (400)	300	1,813,140,867	1,753,175,600			1,193,674,365	1,167,462,735
3	Operating Expenses							
4	Operation Expenses (401)	320	1,129,074,478	1,115,606,858			674,026,748	702,986,085
5	Maintenance Expenses (402)	320	86,720,955	90,443,526			71,447,477	73,669,737
6	Depreciation Expense (403)	336	194,611,959	185,002,792			149,272,689	142,463,452
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	0	0			0	0
8	Amort. & Depl. of Utility Plant (404-405)	336	62,239,993	56,467,917			46,738,641	42,661,543
9	Amort. of Utility Plant Acq. Adj. (406)	336	0	0			0	0
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		0	0				
11	Amort. of Conversion Expenses (407.2)		0	0			0	0
12	Regulatory Debits (407.3)		64,155,411	18,495,696			21,751,021	12,678,285
13	(Less) Regulatory Credits (407.4)		102,019,225	49,733,468			43,048,247	44,548,411
14	Taxes Other Than Income Taxes (408.1)	262	118,141,439	121,401,780			79,882,775	86,410,192
15	Income Taxes - Federal (409.1)	262	2,419,168	(1,018,866)			(7,715,052)	(3,578,734)
16	Income Taxes - Other (409.1)	262	895,264	789,848			20,224	(43,263)
17	Provision for Deferred Income Taxes (410.1)	234, 272	36,404,931	40,312,733			29,355,257	29,270,294

STATEMENT OF INCOME

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	74,741,597	64,172,849			47,088,945	46,062,769
19	Investment Tax Credit Adj. - Net (411.4)	266	(551,283)	(528,730)			(546,563)	(528,748)
20	(Less) Gains from Disp. of Utility Plant (411.6)		0	0				
21	Losses from Disp. of Utility Plant (411.7)		0	0				
22	(Less) Gains from Disposition of Allowances (411.8)		0	0				
23	Losses from Disposition of Allowances (411.9)		0	0				
24	Accretion Expense (411.10)		0	0				
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,517,351,493	1,513,067,237			974,096,025	995,377,663
27	Net Util Oper Inc (Enter Tot line 2 less 25)		295,789,374	240,108,363			219,578,340	172,085,072
28	Other Income and Deductions							
29	Other Income							
30	Nonutilty Operating Income							
31	Revenues From Merchandising, Jobbing and Contract Work (415)			0				
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		0	0				
33	Revenues From Nonutility Operations (417)		0	75,755				
34	(Less) Expenses of Nonutility Operations (417.1)		7,891,784	11,488,060				

STATEMENT OF INCOME								
Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)
35	Nonoperating Rental Income (418)		(1,034)	(6,089)				
36	Equity in Earnings of Subsidiary Companies (418.1)	119	4,449,671	39,795,257				
37	Interest and Dividend Income (419)		15,537,184	2,112,087				
38	Allowance for Other Funds Used During Construction (419.1)		(39,011)	804,751				
39	Miscellaneous Nonoperating Income (421)		16,773	0				
40	Gain on Disposition of Property (421.1)		0	1,747,858				
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		12,071,799	33,041,559				
42	Other Income Deductions							
43	Loss on Disposition of Property (421.2)		40,896	0				
44	Miscellaneous Amortization (425)		5,616	5,616				
45	Donations (426.1)		2,755,476	2,832,367				
46	Life Insurance (426.2)		2,661,064	3,588,360				
47	Penalties (426.3)		25,450	24,039				
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,775,518	1,731,972				
49	Other Deductions (426.5)		1,410,301	4,469,119				
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		8,674,321	12,651,473				
51	Taxes Applic. to Other Income and Deductions							
52	Taxes Other Than Income Taxes (408.2)	262	462,271	670,496				
53	Income Taxes-Federal (409.2)	262	(2,079,651)	(478,795)				

STATEMENT OF INCOME								
Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)
54	Income Taxes-Other (409.2)	262	(75,004)	(668,970)				
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	3,954,988	1,568,707				
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	2,286,595	4,155,913				
57	Investment Tax Credit Adj.-Net (411.5)		0	0				
58	(Less) Investment Tax Credits (420)							
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		(23,991)	(3,064,475)				
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		3,421,469	23,454,561				
61	Interest Charges							
62	Interest on Long-Term Debt (427)		110,131,468	99,558,755				
63	Amort. of Debt Disc. and Expense (428)		1,544,188	470,608				
64	Amortization of Loss on Reaquired Debt (428.1)		1,317,067	1,433,640				
65	(Less) Amort. of Premium on Debt-Credit (429)		8,883	8,883				
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)							
67	Interest on Debt to Assoc. Companies (430)		2,503,671	1,062,531				
68	Other Interest Expense (431)		21,435,607	9,696,574				
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		8,892,489	3,826,333				
70	Net Interest Charges (Total of lines 62 thru 69)		128,030,629	108,386,892				

STATEMENT OF INCOME

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		171,180,214	155,176,032				
72	Extraordinary Items							
73	Extraordinary Income (434)		0	0				
74	(Less) Extraordinary Deductions (435)							
75	Net Extraordinary Items (Total of line 73 less line 74)		0	0				
76	Income Taxes-Federal and Other (409.3)	262	0	0				
77	Extraordinary Items After Taxes (line 75 less line 76)		0	0				
78	Net Income (Total of line 71 and 77)		171,180,214	155,176,032				

STATEMENT OF INCOME				
Line No.	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1				
2	619,466,502	585,712,865		
3				
4	455,047,730	412,620,773		
5	15,273,478	16,773,789		
6	45,339,270	42,539,340		
7	0	0		
8	15,501,352	13,806,374		
9	0	0		
10				
11	0	0		
12	42,404,390	5,817,411		
13	58,970,978	5,185,057		
14	38,258,664	34,991,588		
15	10,134,220	2,559,868		
16	875,040	833,111		
17	7,049,674	11,042,439		
18	27,652,652	18,110,080		
19	(4,720)	18		
20				
21				
22				
23				
24				
25	543,255,468	517,689,574	0	0
27	76,211,034	68,023,291	0	0
28				
29				
30				
31				
32				
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34				

STATEMENT OF INCOME				
Line No.	**Gas Utility Current Year to Date (in dollars) (i)**	**Gas Utility Previous Year to Date (in dollars) (j)**	**Other Utility Current Year to Date (in dollars) (k)**	**Other Utility Previous Year to Date (in dollars) (l)**
35				
36				
37				
38				
39				
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STATEMENT OF INCOME

Line No.	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
68	[redacted]	[redacted]	[redacted]	[redacted]
69	[redacted]	[redacted]	[redacted]	[redacted]
70	[redacted]	[redacted]	[redacted]	[redacted]
71	[redacted]	[redacted]	[redacted]	[redacted]
72	[redacted]	[redacted]	[redacted]	[redacted]
73	[redacted]	[redacted]	[redacted]	[redacted]
74	[redacted]	[redacted]	[redacted]	[redacted]
75	[redacted]	[redacted]	[redacted]	[redacted]
76	[redacted]	[redacted]	[redacted]	[redacted]
77	[redacted]	[redacted]	[redacted]	[redacted]
78	[redacted]	[redacted]	[redacted]	[redacted]

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

STATEMENT OF RETAINED EARNINGS

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		717,509,955	729,502,158
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1				
4.2				
4.3				
4.4				
4.5				
4.6				
4.7				
4.8				
4.9				
4.10				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
10.1				
10.2				
10.3				
10.4				
10.5				
10.6				
10.7				
10.8				
10.9				
10.10				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		166,730,543	115,380,775

STATEMENT OF RETAINED EARNINGS

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)
17	Appropriations of Retained Earnings (Acct. 436)			
17.1	Excess Earnings		(1,835,879)	(3,539,494)
17.2				
17.3				
17.4				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		(1,835,879)	(3,539,494)
23	Dividends Declared-Preferred Stock (Account 437)			
23.1				
23.2				
23.3				
23.4				
23.5				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1	Dividends Declared - Common Stock		(141,368,296)	(129,264,336)
30.2				
30.3				
30.4				
30.5				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(141,368,296)	(129,264,336)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		285,167	5,430,852
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		741,321,490	717,509,955
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
39.1	Appropriated Retained Earnings		56,893,689	55,057,810
39.2				
39.3				
39.4				
39.5				
39.6				

STATEMENT OF RETAINED EARNINGS

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)
45	TOTAL Appropriated Retained Earnings (Account 215)		56,893,689	55,057,810
	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)		56,893,689	55,057,810
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		798,215,179	772,567,765
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		38,974,396	4,609,991
50	Equity in Earnings for Year (Credit) (Account 418.1)		4,449,671	39,795,257
51	(Less) Dividends Received (Debit)			5,000,000
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year		(285,167)	(430,852)
52.1	Corporate Costs Allocated to Subsidiaries		(285,167)	(430,852)
53	Balance-End of Year (Total lines 49 thru 52)		43,138,900	38,974,396

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

STATEMENT OF CASH FLOWS

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)	171,180,214	155,176,032
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	256,851,952	241,470,709
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Deferred Power and Natural Gas Costs	7,171,847	(77,882,317)
5.2	Amortization of Debt Expense	2,852,372	1,895,365
5.3	Amortization of Investment in Exchange Power		
8	Deferred Income Taxes (Net)	(36,037,425)	(26,131,896)
9	Investment Tax Credit Adjustment (Net)	(551,283)	(528,731)
10	Net (Increase) Decrease in Receivables	39,845,414	(57,081,996)
11	Net (Increase) Decrease in Inventory	4,047,260	(22,224,699)
12	Net (Increase) Decrease in Allowances Inventory	(30,071,678)	
13	Net Increase (Decrease) in Payables and Accrued Expenses	[(a)](50,860,477)	[(e)]83,122,813
14	Net (Increase) Decrease in Other Regulatory Assets	(53,098,758)	583,561
15	Net Increase (Decrease) in Other Regulatory Liabilities	34,302,152	10,248,033
16	(Less) Allowance for Other Funds Used During Construction	6,340,790	6,543,085
17	(Less) Undistributed Earnings from Subsidiary Companies	4,449,671	39,795,257
18	Other (provide details in footnote):		
18.1	Cash Received for Settlement of Interest Rate Swaps	7,868,930	
18.2	Other (provide details in footnote):	[(b)]101,860,887	[(f)](141,411,327)
18.3	Allowance for Doubtful Accounts	3,917,172	3,545,696
18.4	Changes in Other Non-Current Assets and Liabilities	(13,741,356)	6,069,824
18.5	Cash Paid for Settlement of Interest Rate Swaps	(409,000)	(17,035,230)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	434,337,762	113,477,495
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	[(c)](490,335,100)	[(g)](449,340,115)

STATEMENT OF CASH FLOWS

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)
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		
31	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(490,335,100)	(449,340,115)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		1,913,172
39	Investments in and Advances to Assoc. and Subsidiary Companies	(11,411,922)	(10,836,472)
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1	Other	1,199,766	1,820,492
53.2	Dividends Received from Subsidiaries	0	5,000,000
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(500,547,256)	(451,442,923)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	250,000,000	399,856,000
62	Preferred Stock		
63	Common Stock	112,308,131	137,778,394

STATEMENT OF CASH FLOWS			
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)
64	Other (provide details in footnote):		
66	Net Increase in Short-Term Debt (c)		179,000,000
67	Other (provide details in footnote):		
70	Cash Provided by Outside Sources (Total 61 thru 69)	362,308,131	716,634,394
72	Payments for Retirement of:		
73	Long-term Debt (b)	(13,500,000)	(250,000,000)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Debt Issuance Costs	(3,323,740)	(5,681,390)
76.2	Minimum Tax Witholdings	[d](1,497,107)	[h](1,462,256)
78	Net Decrease in Short-Term Debt (c)	(114,000,000)	
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(140,922,959)	(129,060,998)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	89,064,325	330,429,750
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)	22,854,831	(7,535,678)
88	Cash and Cash Equivalents at Beginning of Period	5,738,074	13,273,752
90	Cash and Cash Equivalents at End of Period	28,592,905	5,738,074

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: NetIncreaseDecreaseInPayablesAndAccruedExpensesOperatingActivities

Cash paid (received) during the period for:

Income taxes: $(1,439,727)

Interest: $125,249,194

(b) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Power and natural gas deferrals (6,119,299); Change in special deposits 129,225,987; Change in other current assets (26,445,069); Non-cash stock compensation 8,441,581; Loss on sale of property and equipment 40,896; Other (3,283,209).

(c) Concept: GrossAdditionsToUtilityPlantLessNuclearFuelInvestingActivities

Additions to PPE in Accounts Payable: $33,691,044

(d) Concept: OtherRetirementsOfBalancesImpactingCashFlowsFromFinancingActivities

Payment of minimum tax withholdings for share-based payment awards

(e) Concept: NetIncreaseDecreaseInPayablesAndAccruedExpensesOperatingActivities

Cash paid during the period for:

Income taxes: $445,203

Interest: $101,077,254

(f) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Power and natural gas deferrals (1,797,792); Change in special deposits (141,014,015); Change in other current assets (6,946,745); Non-cash stock compensation 8,716,734; Gain on sale of property and equipment (1,747,858); Other 1,378,349.

(g) Concept: GrossAdditionsToUtilityPlantLessNuclearFuelInvestingActivities

Additions to PPE in Accounts Payable: $27,708,348

(h) Concept: OtherRetirementsOfBalancesImpactingCashFlowsFromFinancingActivities

Payment of minimum tax withholdings for share-based payment awards

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 were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

NOTES TO FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Avista Corp. (the Company) is primarily an electric and natural gas utility with certain other business ventures. Avista Corp. provides electric distribution and transmission, and natural gas distribution services in parts of eastern Washington and northern Idaho. Avista Corp. also provides natural gas distribution service in parts of northeastern and southwestern Oregon. Avista Corp. has electric generating facilities in Washington, Idaho, Oregon and Montana. Avista Corp. also supplies electricity to a small number of customers in Montana.

Alaska Electric and Resource Company (AERC) is a wholly-owned subsidiary of Avista Corp. The primary subsidiary of AERC is Alaska Electric Light and Power (AEL&P), which comprises Avista Corp.'s regulated utility operations in Alaska.

Avista Capital, a wholly owned non-regulated subsidiary of Avista Corp., is the parent company of the subsidiary companies except AERC (and its subsidiaries).

Basis of Reporting

The financial statements include the assets, liabilities, revenues and expenses of the Company and have been prepared in accordance with the accounting requirements of the Federal Energy Regulation Commission (FERC) as set forth in its applicable Uniform Systems 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 (U.S. GAAP). As required by the FERC, the Company accounts for its investment in majority owned subsidiaries as required by U.S. GAAP. The accompanying financial statements include the Company's proportionate share of utility plant and related operations associated with its interests in jointly owned plants. In addition, under the requirements of the FERC, there are differences from U.S. GAAP in the presentation of (1) current portion of long-term debt, (2) assets and liabilities for cost of removal of assets, (3) assets held for Sale, (4) regulatory assets and liabilities, (5) deferred income taxes associated with accounts other than utility property, plant and equipment, (6) comprehensive income, (7) unamortized debt issuance costs, (8) operating revenues and resource costs associated with settled energy contracts that are "booked out", (9) non-service portion of pension and other postretirement benefit costs, and (10) leases.

Use of Estimates

The preparation of the financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported for assets and liabilities and the 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. Significant estimates include:

- determining the market value of energy commodity derivative assets and liabilities,
- pension and other postretirement benefit plan obligations,
- contingent liabilities,
- goodwill impairment testing,
- recoverability of regulatory assets, and
- unbilled revenues.

Changes in these estimates and assumptions are considered reasonably possible and may have a material effect on the financial statements and thus actual results could differ from the amounts reported and disclosed herein.

System of Accounts

The accounting records of the Company's utility operations are maintained in accordance with the uniform system of accounts prescribed by the FERC and adopted by the state regulatory commissions in Washington, Idaho, Montana and Oregon.

Regulation

The Company is subject to state regulation in Washington, Idaho, Montana, Oregon and Alaska. The Company is subject to federal regulation primarily by the FERC, as well as various other federal agencies with regulatory oversight of particular aspects of its operations.

Depreciation

For utility operations, depreciation expense is estimated by a method of depreciation accounting utilizing composite rates for utility plant. Such rates are designed to provide for retirements of properties at the expiration of their service lives. For utility operations, the ratio of depreciation provisions to average depreciable property was as follows for the years ended December 31:

	2023	2022
Avista Corp.	3.52%	3.50%

The average service lives for the following broad categories of utility plant in service are (in years):

Electric thermal/other production	26
Hydroelectric production	79
Electric transmission	50
Electric distribution	40
Natural gas distribution property	44
Other shorter-lived general plant	8

Allowance for Funds Used During Construction (AFUDC)

AFUDC represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period. As prescribed by regulatory authorities, AFUDC is capitalized as a part of the cost of utility plant. The debt component of AFUDC is credited against total interest expense in the Statements of Income in the line item "capitalized interest." The equity component of AFUDC is included in the Statements of Income in the line item "other income-net." The Company is permitted, under established regulatory rate practices, to recover the capitalized AFUDC, and a reasonable return thereon, through its inclusion in rate base and the provision for depreciation after the related utility plant is placed in service. Cash inflow related to AFUDC does not occur until the related utility plant is placed in service and included in rate base.

The WUTC and IPUC have authorized Avista Corp. to calculate AFUDC using its allowed rate of return. To the extent amounts calculated using this rate exceed the AFUDC amounts calculated using the FERC formula, Avista Corp. capitalizes the excess as a regulatory asset. The regulatory asset associated with plant in service is amortized over the average useful life of Avista Corp.'s utility plant which is approximately 30 years. The regulatory asset associated with construction work in progress is not amortized until the plant is placed in service.

The effective AFUDC rate was the following for the years ended December 31:

	2023	2022
Avista Corp.	7.03%	7.12%

Income Taxes

Deferred income tax assets represent future income tax deductions the Company expects to utilize in future tax returns to reduce taxable income. Deferred income tax liabilities represent future taxable income the Company expects to recognize in future tax returns. Deferred tax assets and liabilities arise when there are temporary differences resulting from differing treatment of items for tax and accounting purposes. A deferred income tax asset or liability is determined based on the enacted tax rates that will be in effect when the temporary differences between the financial statement carrying amounts and tax basis of existing assets and liabilities are expected to be reported in the Company's income tax returns. The effect on deferred income taxes from a change in tax rates is recognized in income in the period that includes the enactment date unless a regulatory order specifies deferral of the effect of the change in tax rates over a longer period of time. The Company establishes a valuation allowance when it is more likely than not that all, or a portion, of a deferred tax asset will not be realized. Deferred income tax assets and liabilities and regulatory assets and liabilities are established for income tax benefits flowed through to customers.

The Company has elected to account for transferable tax credits as a component of the income tax provision. The Company recognizes the benefit of production tax credits as a reduction of income tax expense in the period the credit is generated, which corresponds to the period the energy production occurs. The Company applies the deferral method of accounting for investment tax credits (ITCs). Under this method, ITCs are amortized as a reduction to income tax expense over the estimated useful lives of the underlying property that gave rise to the credit.

The Company's largest deferred income tax item is the difference between the book and tax basis of utility plant. This item results from the temporary difference on depreciation expense. In early tax years, this item is recorded as a deferred income tax liability that will eventually reverse and become subject to income tax in later tax years.

The Company did not incur penalties on income tax positions in 2023or 2022. The Company would recognize interest accrued related to income tax positions as interest expense or interest income and penalties incurred as other operating expense.

Stock-Based Compensation

The Company issues three types of stock-based compensation awards - restricted shares, market-based awards and performance-based awards. Compensation cost relating to share-based payment transactions is recognized in the Company's financial statements based on the fair value of the equity instruments issued and recorded over the requisite service period.

The Company recorded stock-based compensation expense (included in other operating expenses) and income tax benefits in the Statements of Income of the following amounts for the years ended December 31 (dollars in thousands):

	2023	2022
Stock-based compensation expense	$ 7,144	$ 7,567
Income tax benefits	1,500	1,589
Excess tax benefits (expenses) on settled share-based employee payments	84	(19)

Restricted share awards vest in equal thirds each year over 3 years and are payable in Avista Corp. common stock at the end of each year if the service condition is met. Restricted stock is valued at the close of market of the Company's common stock on the grant date.

Total Shareholder Return (TSR) awards are market-based awards and Cumulative Earnings Per Share (CEPS) awards are performance awards. Both types of awards vest after a period of 3 years and are payable in cash or Avista Corp. common stock at the end of the three-year period. The method of settlement is at the discretion of the Company and historically the Company has settled these awards through issuance of Avista Corp. common stock and intends to continue this practice. Both types of awards entitle the recipients to dividend equivalent rights, are subject to forfeiture under certain circumstances, and are subject to meeting specific market or performance conditions. Based on the level of attainment of the market or performance conditions, the amount of cash paid or common stock issued will range from 0 to 200 percent of the initial awards granted. Dividend equivalent rights are accumulated and paid out only on shares that have vested and have met the market and performance conditions.

The Company accounts for both the TSR awards and CEPS awards as equity awards and compensation cost for these awards is recognized over the requisite service period, provided the requisite service period is rendered. For TSR awards, if the market condition is not met at the end of the three-year service period, there will be no change in the cumulative amount of compensation cost recognized, since the awards are still considered vested even though the market metric was not met. For CEPS awards, at the end of the three-year service period, if the internal performance metric of cumulative earnings per share is not met, all compensation cost for these awards is reversed as these awards are not considered vested.

The fair value of each TSR award is estimated on the date of grant using a statistical model incorporating the probability of meeting the market targets based on historical returns relative to a peer group. CEPS awards are valued at the close of market of the Company's common stock on the grant date.

The following table summarizes the number of grants, vested and unvested shares, earned shares (based on market metrics), and other pertinent information related to the Company's stock compensation awards for the years ended December 31:

	2023	2022
Restricted Shares		
Shares granted during the year	76,806	115,746
Shares vested during the year	75,007	44,829
Unvested shares at end of year	152,140	157,860
Unrecognized compensation expense at end of year (in thousands)	$ 3,477	$ 3,923
TSR Awards		
TSR shares granted during the year	34,912	69,814
TSR shares vested during the year	61,456	43,730
TSR shares earned based on market metrics	44,863	48,890

Unvested TSR shares at end of year	96,915	130,567
Unrecognized compensation expense at end of year (in thousands)	$ 2,235	$ 3,533
CEPS Awards		
CEPS shares granted during the year	104,685	69,814
CEPS shares vested during the year	61,456	43,730
CEPS shares earned based on performance metrics	33,801	
Unvested CEPS shares at end of year	161,235	130,567
Unrecognized compensation expense at end of year (in thousands)	$ 2,439	$ 2,471

Outstanding restricted, TSR and CEPS share awards include a dividend component paid in cash. A liability for the dividends payable related to these awards is accrued as dividends are announced throughout the life of the award. As of December 31, 2023 and 2022, the Company had recognized a liability of $2.2 million and $1.7 million, respectively, related to the dividend equivalents payable on the outstanding and unvested share grants.

Cash and Cash Equivalents

For the purposes of the Statements of Cash Flows, the Company considers all temporary investments with a maturity of three months or less when purchased to be cash equivalents.

Allowance for Doubtful Accounts

The Company maintains an allowance for doubtful accounts to provide for estimated and potential losses on accounts receivable. The Company determines the allowance for utility and other customer accounts receivable based on historical write-offs as compared to accounts receivable and operating revenues. Additionally, the Company establishes specific allowances for certain individual accounts

Utility Plant in Service

The cost of additions to utility plant in service, including AFUDC and replacements of units of property and improvements, is capitalized. The cost of depreciable units of property retired plus the cost of removal less salvage is charged to accumulated depreciation.

Asset Retirement Obligations (ARO)

The Company records the fair value of a liability for an ARO in the period in which it is incurred. When the liability is initially recorded, the associated costs of the ARO are capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the related capitalized costs are depreciated over the useful life of the related asset. In addition, if there are changes in the estimated timing or estimated costs of the AROs, adjustments are recorded during the period new information becomes available as an increase or decrease to the liability, with the offset recorded to the related long-lived asset. Upon retirement of the asset, the Company either settles the ARO for its recorded amount or recognizes a regulatory asset or liability for the difference, which will be surcharged/refunded to customers through the ratemaking process. The Company records regulatory assets and liabilities for the difference between asset retirement costs currently recovered in rates and AROs recorded since asset retirement costs are recovered through rates charged to customers (see Note 11 for further discussion of the Company's AROs).

Derivative Assets and Liabilities

Derivatives are recorded as either assets or liabilities on the Balance Sheets measured at estimated fair value.

The Washington Utilities and Transportation Commission (WUTC) and the Idaho Public Utilities Commission (IPUC) issued accounting orders authorizing Avista Corp. to offset energy commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of delivery. Realized benefits and costs result in adjustments to retail rates through Purchase Gas Adjustments (PGAs), the Energy Recovery Mechanism (ERM) in Washington, the Power Cost Adjustment (PCA) mechanism in Idaho, and periodic general rate cases. The resulting regulatory assets associated with energy commodity derivative instruments are probable of recovery through future rates.

Substantially all forward contracts to purchase or sell power and natural gas are recorded as derivative assets or liabilities at estimated fair value with an offsetting regulatory asset or liability. Contracts not considered derivatives are accounted for on the accrual basis until they are settled or realized unless there is a decline in the fair value of the contract determined to be other-than-temporary.

For interest rate swap derivatives, Avista Corp. records all mark-to-market gains and losses in each accounting period as assets and liabilities, as well as offsetting regulatory assets and liabilities, such that there is no income statement impact. The interest rate swap derivatives are risk management tools similar to energy commodity derivatives. Upon settlement of interest rate swap derivatives, the regulatory asset or liability is amortized as a component of interest expense over the term of the associated debt. The Company records an offset of interest rate swap derivative assets and liabilities with regulatory assets and liabilities, based on the prior practice of the commissions to provide recovery through the ratemaking process.

The Company has multiple master netting agreements with a variety of entities allowing for cross-commodity netting of derivative agreements with the same counterparty (i.e. power derivatives can be netted with natural gas derivatives). In addition, some master netting agreements allow for the netting of commodity derivatives and interest rate swap derivatives for the same counterparty. The Company does not have agreements which allow for cross-affiliate netting among multiple affiliated legal entities. The Company nets all derivative instruments when allowed by the agreement for presentation in the Balance Sheets.

Fair Value Measurements

Fair value represents the price that would be received when selling an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Energy commodity derivative assets and liabilities, deferred compensation assets, as well as derivatives related to interest rate swaps and foreign currency exchange contracts, are reported at estimated fair value on the Balance Sheets. See Note 13 for the Company's fair value disclosures.

Regulatory Deferred Charges and Credits

The Company prepares its financial statements in accordance with regulatory accounting practices because:

- rates for regulated services are established by or subject to approval by independent third-party regulators,
- the regulated rates are designed to recover the cost of providing the regulated services, and
- in view of demand for the regulated services and the level of competition, it is reasonable to assume that rates can be charged to and collected from customers at levels that will recover costs.

Regulatory accounting practices require certain costs and/or obligations (such as incurred power and natural gas costs not currently reflected in rates, but expected to be recovered or refunded in the future), to be reflected as deferred charges or credits on the Balance Sheets. These costs and/or obligations are not reflected in the Statements of Income until the period during which matching revenues are recognized. The Company also has decoupling revenue deferrals. See Note 2 for discussion on decoupling revenue deferrals.

If at some point in the future the Company determines it no longer meets the criteria for continued application of regulatory accounting practices for all or a portion of its regulated operations, the Company could be:

- required to write off its regulatory assets, and
- precluded from the future deferral of costs or decoupled revenues not recovered through rates at the time such amounts are incurred, even if the Company expected to recover these amounts from customers in the future.

Unamortized Debt Expense

Unamortized debt expense includes debt issuance costs that are amortized over the life of the related debt.

Unamortized Debt Repurchase Costs

For the Company's Washington regulatory jurisdiction and for any debt repurchases beginning in 2007 in all jurisdictions, premiums and discounts paid to repurchase debt are amortized over the remaining life of the original debt repurchased or, if new debt is issued in connection with the repurchase, these amounts are amortized over the life of the new debt. In the Company's other regulatory jurisdictions, premiums or discounts paid to repurchase debt prior to 2007 are being amortized over the average remaining maturity of outstanding debt when no new debt was issued in connection with the debt repurchase. The premium and discount costs are recovered or returned to customers through retail rates as a component of interest expense.

Appropriated Retained Earnings

In accordance with the hydroelectric licensing requirements of section 10(d) of the Federal Power Act (FPA), the Company maintains an appropriated retained earnings account for earnings in excess of the specified rate of return on the Company's investment in the licenses for its various hydroelectric projects. Per section 10(d) of the FPA, the Company must maintain these excess earnings in an appropriated retained earnings account until the termination of the licensing agreements or apply them to reduce the net investment in the licenses of the hydroelectric projects at the discretion of the FERC. The Company calculates the earnings in excess of the specified rate of return on an annual basis, usually during the second quarter.

The appropriated retained earnings amounts included in retained earnings were as follows as of December 31 (dollars in thousands):

	2023	2022
Appropriated retained earnings	$ 56,894	$ 55,058

Contingencies

The Company has unresolved regulatory, legal and tax issues which have inherently uncertain outcomes. The Company accrues a loss contingency if it is probable that a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. The Company also discloses loss contingencies that do not meet these conditions for accrual, if there is a reasonable possibility that a material loss may be incurred. As of December 31, 2023, the Company has not recorded significant amounts related to unresolved contingencies. See Note 15 for further discussion of the Company's commitments and contingencies.

Equity in Earnings (Losses) of Subsidiaries

The Company records all the earnings (losses) from its subsidiaries under the equity method. The Company had the following equity in earnings (losses) of its subsidiaries for the years ended December 31 (dollars in thousands):

	2023	2022
Avista Capital	$ (4,288)	$ 32,423
AERC	8,738	7,372
Total equity in earnings of subsidiary companies	$ 4,450	$ 39,795

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2023 up to February 20, 2024, the date that Avista Corp.'s U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through the date of this filing. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

NOTE 2. REVENUE

The core principle of the revenue recognition model is that an entity should identify the various performance obligations in a contract, allocate the transaction price among the performance obligations and recognize revenue when (or as) the entity satisfies each performance obligation.

Utility Revenues

Revenue from Contracts with Customers

General

The majority of Avista Corp.'s revenue is from rate-regulated sales of electricity and natural gas to retail customers, which has two performance obligations, (1) having service available for a specified period (typically a month at a time) and (2) the delivery of energy to customers. The total energy price generally has a fixed component (basic charge) related to having service available and a usage-based component, related to the delivery and consumption of energy. The commodity is sold and/or delivered to and consumed by the customer simultaneously, and the provisions of the relevant utility commission authorization determine the charges the Company may bill the customer. Since all revenue recognition criteria are met upon the delivery of energy to customers, revenue is recognized immediately.

In addition, the sale of electricity and natural gas is governed by the various state utility commissions, which set rates, charges, terms and conditions of service, and prices. Collectively, these rates, charges, terms and conditions are included in a "tariff," which governs all aspects of the provision of regulated services. Tariffs are only permitted to be changed through a rate-setting process involving an independent, third-party regulator empowered by statute to establish rates that bind customers. Thus, all regulated sales by the Company are conducted subject to the regulator-approved tariff.

Tariff sales involve the current provision of commodity service (electricity and/or natural gas) to customers for a price that generally has a basic charge and a usage-based component. Tariff rates also include certain pass-through costs to customers such as natural gas costs, retail revenue credits and other miscellaneous regulatory items that do not impact net income, but can cause total revenue to fluctuate significantly up or down compared to previous periods. The commodity is sold and/or delivered to and consumed by the customer simultaneously, and the provisions of the relevant tariff determine the charges the Company may bill the customer, payment due date, and other pertinent rights and obligations of both parties. Generally, tariff sales do not involve a written contract. Since all revenue recognition criteria are met upon the delivery of energy to customers, revenue is recognized at that time.

Unbilled Revenue from Contracts with Customers

The determination of the volume of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month (once per month for each individual customer). At the end of each calendar month, the amount of energy delivered to customers since the date of the last meter reading is estimated and the corresponding unbilled revenue is estimated and recorded. The Company's estimate of unbilled revenue is based on:

the number of customers,

tariff rates,

meter reading dates,

actual native load for electricity,

actual throughput for natural gas, and

electric line losses and natural gas system losses.

Any difference between actual and estimated revenue is automatically corrected in the following month when the meter reading and customer billing occurs.

Accounts receivable includes unbilled energy revenues of the following amounts as of December 31 (dollars in thousands):

	2023	2022
Unbilled accounts receivable	$ 75,650	$ 78,873

Non-Derivative Wholesale Contracts

The Company has certain wholesale contracts that are not accounted for as derivatives and are considered revenue from contracts with customers. Revenue is recognized as energy is delivered to the customer or the service is available for specified period of time, consistent with the discussion of rate regulated sales above.

Alternative Revenue Programs (Decoupling)

ASC 606 retained existing GAAP associated with alternative revenue programs, which specified alternative revenue programs are contracts between an entity and a regulator of utilities, not a contract between an entity and a customer. GAAP requires the presentation of revenue arising from alternative revenue programs separately from revenues arising from contracts with customers on the Statements of Income. The Company's decoupling mechanisms (also known as a FCA in Idaho) qualify as alternative revenue programs. Decoupling revenue deferrals are recognized in the Statements of Income during the period they occur (i.e. during the period of revenue shortfall or excess due to fluctuations in customer usage), subject to certain limitations, and a regulatory asset or liability is established which will be surcharged or rebated to customers in future periods. GAAP requires that for an alternative revenue program, like decoupling, the revenue must be expected to be collected from customers within 24 months of the deferral to qualify for recognition in the Statements of Income. Amounts included in the Company's decoupling program that are not expected to be collected from customers within 24 months are not recorded in the financial statements until the period in which revenue recognition criteria are met. The amounts expected to be collected from customers within 24 months represents an estimate made by the Company on an ongoing basis due to it being based on the volumes of electric and natural gas sold to customers on a go-forward basis.

The Company records alternative program revenues under the gross method, which is to amortize the decoupling regulatory asset/liability to the alternative revenue program line item on the Statements of Income as it is collected from or refunded to customers. The cash passing between the Company and the customers is presented in revenue from contracts with customers since it is a portion of the overall tariff paid by customers. This method results in a gross-up to both revenue from contracts with customers and revenue from alternative revenue programs, but has a net zero impact on total revenue. Depending on whether the previous deferral balance being amortized was a regulatory asset or regulatory liability, and depending on the size and direction of the current year deferral of surcharges and/or rebates to customers, it could result in negative alternative revenue program revenue during the year.

Derivative Revenue

Most wholesale electric and natural gas transactions (including both physical and financial transactions), and the sale of fuel are considered derivatives, which are disclosed separately from revenue from contracts with customers. Revenue is recognized for these items upon the settlement/expiration of the derivative contract. Derivative revenue includes transactions entered into and settled within the same month.

Other Utility Revenue

Other utility revenue includes rent, sales of materials, late fees and other charges that do not represent contracts with customers. This revenue is excluded from revenue from contracts with customers, as this revenue does not represent items where a customer is a party that has contracted with the Company to obtain goods or services that are an output of the Company's ordinary activities in exchange for consideration. As such, these revenues are presented separately from revenue from contracts with customers.

Other Considerations for Utility Revenues

Gross Versus Net Presentation

Utility-related taxes collected from customers (primarily state excise taxes and city utility taxes) are imposed on Avista Corp. as opposed to being imposed on customers; therefore, Avista Corp. is the taxpayer and records these transactions on a gross basis in revenue from contracts with customers and operating expense (taxes other than income taxes).

Utility-related taxes included in revenue from contracts with customers were as follows for the years ended December 31 (dollars in thousands):

	2023	2022
Utility-related taxes	$ 75,404	$ 69,931

Significant Judgments and Unsatisfied Performance Obligations

The only significant judgments involving revenue recognition are estimates surrounding unbilled revenue and receivables from contracts with customers and estimates surrounding the amount of decoupling revenues that will be collected from customers within 24 months (discussed above).

The Company has certain capacity arrangements, where the Company has a contractual obligation to provide either electric or natural gas capacity to its customers for a fixed fee. Most of these arrangements are paid for in arrears by the customers and do not result in deferred revenue and only result in receivables from the customers. The Company has one capacity agreement where the customer makes payments throughout the year. As of December 31, 2023, the Company estimates it had unsatisfied capacity performance obligations of $7.4 million, which will be recognized as revenue in future periods as the capacity is provided to the customers. These performance obligations are not reflected in the financial statements, as the Company has not received payment for these services.

NOTE 3. LEASES

The core principle of lease accounting is that an entity should recognize the ROU assets and liabilities from leases on the balance sheet and depreciate or amortize the asset and liability over the term of the lease, as well as provide disclosure to enable users of the financial statements to assess the amount, timing, and uncertainty of cash flows from leases. For regulatory reporting, the FERC provided prescribed accounts for the ROU assets and liabilities, with the ROU assets being included in utility plant (FERC account 101) and the lease liabilities being included in capital lease obligations (FERC account 227). These accounts are different than the accounts allowed for in GAAP reporting, which results in a FERC/GAAP difference.

Significant Judgments and Assumptions

The Company determines if an arrangement is a lease, as well as its classification, at its inception.

ROU assets represent the Company's right to use an underlying asset for the lease term, and lease liabilities represent the Company's obligation to make lease payments. Operating lease ROU assets and lease liabilities are recognized at the commencement date of the agreement based on the present value of lease payments over the lease term. As most of the Company's leases do not provide an implicit rate, the Company uses its incremental borrowing rate based on the information available at the commencement date to determine the present value of lease payments. The implicit rate is used when it is readily determinable. The operating lease ROU assets also includes lease payments made and exclude lease incentives, if any, that accrue to the benefit of the lessee.

Lease terms may include options to extend or terminate the lease when it is reasonably certain the Company will exercise that option. Lease expense is recognized on a straight-line basis over the lease term. The difference between lease expense and cash paid for leased assets is recognized as a regulatory asset or regulatory liability.

Description of Leases

Operating Leases

The Company's most significant operating lease is with the State of Montana associated with submerged land around the Company's hydroelectric facilities in the Clark Fork River basin, which expires in 2046. The terms of this lease are subject to adjustment - depending on the outcome of ongoing litigation between the State of Montana and NorthWestern. In addition, the State of Montana and Avista Corp. were engaged in litigation regarding lease terms, including how much money, if any, the State of Montana should return to Avista Corp.; however, that litigation was dismissed as premature pending the outcome of the ongoing litigation between the State of Montana and NorthWestern. Any reduction in future lease payments or the return to Avista Corp. of amounts previously paid will be included in the future ratemaking process.

In addition to the lease with the State of Montana, the Company has other operating leases for land associated with its utility operations, as well as communication sites which support network and radio communications within its service territory. The Company's leases have remaining terms of 1 to 70 years. Most of the Company's leases include options to extend the lease term for periods of 5 to 50 years. Options are exercised at the Company's discretion.

Certain of the Company's lease agreements include rental payments which are periodically adjusted over the term of the agreement based on the consumer price index. The Company's lease agreements do not include material residual value guarantees or material restrictive covenants.

In March 2023, the Company entered into an agreement with Rathdrum Power, LLC amending and restating a PPA for the output of the Lancaster Plant. The restated PPA meets the accounting definition of a lease, and all payments are variable in nature, based on capacity, usage, or performance of the plant. Therefore, there is no lease obligation or corresponding ROU asset recorded by the Company related to this agreement. The variable lease costs related to this agreement are included in resource costs on the Statements of Income.

Avista Corp. does not record leases with a term of 12 months or less in the Balance Sheets. Total short-term lease costs for the year ended December 31, 2023 are immaterial.

The components of lease expense were as follows for the year ended December 31 (dollars in thousands):

	2023	2022	2021
Operating lease cost:			
Fixed lease cost (Other operating expenses)	$ 5,096	$ 4,986	$ 4,970
Variable lease cost (Other operating expenses and Resource costs)	24,628	1,567	1,180
Total operating lease cost	$ 29,724	$ 6,553	$ 6,150

Supplemental cash flow information related to leases was as follows for the year ended December 31 (dollars in thousands):

	2023	2022	2021

Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash outflows:			
Operating lease payments	$ 4,960	$ 4,828	$ 4,805

Supplemental balance sheet information related to leases was as follows for December 31 (dollars in thousands):

	December 31, 2023	December 31, 2022
Operating Leases		
Operating lease ROU assets (Utility Plant)	$ 67,585	$ 68,238
Obligations under capital lease - current	$ 4,490	$ 4,349
Obligations under capital lease - noncurrent	63,559	64,284
Total operating lease liabilities	$ 68,049	$ 68,633
Weighted Average Remaining Lease Term		
Operating leases	22.28 years	23.28 years
Weighted Average Discount Rate		
Operating leases	4.29 %	4.28 %

Maturities of lease liabilities (including principal and interest) were as follows as of December 31, 2023 (dollars in thousands):

	Operating Leases
2024	$ 4,988
2025	4,984
2026	4,981
2027	5,007
2028	4,992
Thereafter	83,532
Total lease payments	$ 108,484
Less: imputed interest	(40,435)
Total	$ 68,049

Maturities of lease liabilities (including principal and interest) were as follows as of December 31, 2022 (dollars in thousands):

	Operating Leases
2023	$ 4,850
2024	4,877
2025	4,884
2026	4,869
2027	4,880
Thereafter	86,991
Total lease payments	$ 111,351
Less: imputed interest	(42,718)
Total	$ 68,633

NOTE 4. DERIVATIVES AND RISK MANAGEMENT

Energy Commodity Derivatives

Avista Corp. is exposed to market risks relating to changes in electricity and natural gas commodity prices and certain other fuel prices. Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. Avista Corp. utilizes derivative instruments, such as forwards, futures, swap derivatives and options to manage the various risks relating to these commodity price exposures. Avista Corp. has an energy resources risk policy and control procedures to manage these risks.

As part of Avista Corp.'s resource procurement and management operations in the electric business, Avista Corp. engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve Avista Corp.'s load obligations and the use of these resources to capture available economic value through wholesale market transactions. These include sales and purchases of electric capacity and energy, fuel for electric generation, and derivative contracts related to capacity, energy and fuel. Such transactions are part of the process of matching resources with load obligations and hedging a portion of the related financial risks. These transactions range from terms of intra-hour up to multiple years.

As part of its resource procurement and management of its natural gas business, Avista Corp. makes continuing projections of its natural gas loads and assesses available natural gas resources including natural gas storage availability. Natural gas resource planning typically includes peak requirements, low and average monthly requirements and delivery constraints from natural gas supply locations to Avista Corp.'s distribution system. However, daily variations in natural gas demand can be significantly different than monthly demand projections. Based on these projections, Avista Corp. plans and executes a series of transactions to hedge a portion of its projected natural gas requirements through forward market transactions and derivative instruments. These transactions may extend as much as three natural gas operating years (November through October) into the future. Avista Corp. also leaves a significant portion of its natural gas supply requirements unhedged for purchase in short-term and spot markets.

Avista Corp. plans for sufficient natural gas delivery capacity to serve its retail customers for a theoretical peak day event. Avista Corp. generally has more pipeline and storage capacity than what is needed during periods other than a peak day. Avista Corp. optimizes its natural gas resources by using market opportunities to generate economic value that mitigates the fixed costs. Avista Corp. also optimizes its natural gas storage capacity by purchasing and storing natural gas when prices are traditionally lower, typically in the summer, and withdrawing during higher priced months, typically during the winter. However, if market conditions and prices indicate that Avista Corp. should buy or sell natural gas at other times during the year, Avista Corp. engages in optimization transactions to capture value in the marketplace. Natural gas optimization activities include, but are not limited to, wholesale market sales of surplus natural gas supplies, purchases and sales of natural gas to optimize use of pipeline and storage capacity, and participation in the transportation capacity release market.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2023 expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs
2024	9		22,747	74,596	472	510	1,723	12,038
2025			12,505	19,590	11	96	1,115	1,125
2026			5,570	3,940				

As of December 31, 2023, there are no expected deliveries of energy commodity derivatives after 2026.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2022 that were expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs
2023	5		19,140	79,253	136	1,011	4,145	29,473
2024			533	30,658			1,370	9,668
2025			450	4,895			1,115	1,125

As of December 31, 2022, there were no expected deliveries of energy commodity derivatives after 2025.

(1)Physical transactions represent commodity transactions in which Avista Corp. will take or make delivery of either electricity or natural gas; financial transactions represent derivative instruments with delivery of cash in the amount of the benefit or cost but with no physical delivery of the commodity, such as futures, swap derivatives, options, or forward contracts.

The electric and natural gas derivative contracts above will be included in either power supply costs or natural gas supply costs during the period they are scheduled to be delivered and will be included in the various deferral and recovery mechanisms (ERM, PCA, and PGAs), or in the general rate case process, and are expected to be recovered through retail rates from customers.

Foreign Currency Exchange Derivatives

A significant portion of Avista Corp.'s natural gas supply (including fuel for power generation) is obtained from Canadian sources. Most of those transactions are executed in U.S. dollars, which avoids foreign currency risk. A portion of Avista Corp.'s short-term natural gas transactions and long-term Canadian transportation contracts are committed based on Canadian currency prices. The short term natural gas transactions are settled within 60 days with U.S. dollars. Avista Corp. hedges a portion of the foreign currency risk by purchasing Canadian currency exchange derivatives when such commodity transactions are initiated. The foreign currency exchange derivatives and the unhedged foreign currency risk have not had a material effect on Avista Corp.'s financial condition, results of operations or cash flows and these differences in cost related to currency fluctuations are included with natural gas supply costs for ratemaking.

The following table summarizes the foreign currency exchange derivatives outstanding as of December 31 (dollars in thousands):

	2023	2022
Number of contracts	5	19
Notional amount (in United States dollars)	$ 81	$ 8,563
Notional amount (in Canadian dollars)	109	11,659

Interest Rate Swap Derivatives

Avista Corp. is affected by fluctuating interest rates related to a portion of its existing debt, and future borrowing requirements. Avista Corp. may hedge a portion of its interest rate risk with financial derivative instruments, including interest rate swap derivatives. These interest rate swap derivatives are considered economic hedges against fluctuations in future cash flows associated with anticipated debt issuances.

The following table summarizes the unsettled interest rate swap derivatives outstanding as of the balance sheet date indicated below (dollars in thousands):

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
December 31, 2023	2	$ 20,000	2024
	1	10,000	2025
December 31, 2022	4	$ 40,000	2023
	1	10,000	2024

The fair value of outstanding interest rate swap derivatives can vary significantly from period to period depending on the total notional amount of swap derivatives outstanding and fluctuations in market interest rates compared to the interest rates fixed by the swaps. Avista Corp. is required to make cash payments to settle the interest rate swap derivatives when the fixed rates are higher than prevailing market rates at the date of settlement. Conversely, Avista Corp. receives cash to settle its interest rate swap derivatives when prevailing market rates at the time of settlement exceed the fixed swap rates.

Summary of Outstanding Derivative Instruments

The amounts recorded on the Balance Sheets as of December 31, 2023 and December 31, 2022 reflect the offsetting of derivative assets and liabilities where a legal right of offset exists.

The following table presents the fair values and locations of derivative instruments recorded on the Balance Sheets as of December 31, 2023 (dollars in thousands):

	Fair Value			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) on Balance Sheet
Foreign currency exchange derivatives				
Derivative instrument assets current	$ 2	$	$	$ 2
Interest rate swap derivatives				
Derivative instrument assets current	3,667			3,667
Long-term portion of derivative liabilities		(182)		(182)
Energy commodity derivatives				
Derivative instrument assets current	8,531	(379)		8,152
Derivative instrument liabilities current	19,510	(79,082)	42,355	(17,217)
Long-term portion of derivative liabilities	2,913	(20,633)		(17,720)
Total derivative instruments recorded on the balance sheet	$ 34,623	$ (100,276)	$ 42,355	$ (23,298)

The following table presents the fair values and locations of derivative instruments recorded on the Balance Sheets as of December 31, 2022 (dollars in thousands):

	Fair Value			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) on Balance Sheet
Foreign currency exchange derivatives				
Derivative instrument assets current	$ 43	$	$	$ 43
Derivative instrument liabilities current		(3)		(3)
Interest rate swap derivatives				
Derivative instrument assets current	8,536			8,536
Long-term portion of derivative assets	2,648			2,648
Derivative instrument liabilities current		(52)		(52)
Energy commodity derivatives				
Derivative instrument assets current	32,257	(22,638)		9,619
Long-term portion of derivative assets	312	(16)		296
Derivative instrument liabilities current	107,902	(229,607)	94,850	(26,855)
Long-term portion of derivative liabilities	6,049	(24,530)	10,589	(7,892)
Total derivative instruments recorded on the balance sheet	$ 157,747	$ (276,846)	$ 105,439	$ (13,660)

Exposure to Demands for Collateral

Avista Corp.'s derivative contracts often require collateral (in the form of cash or letters of credit) or other credit enhancements, or reductions or terminations of a portion of the contract through cash settlement. In the event of changes in market prices or a downgrade in Avista Corp.'s credit ratings or other established credit criteria, additional collateral may be required. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against Avista Corp.'s credit facilities and cash. Avista Corp. actively monitors the exposure to possible collateral calls and takes steps to mitigate capital requirements.

The following table presents collateral outstanding related to its derivative instruments as of December 31 (dollars in thousands):

	2023	2022
Energy commodity derivatives		
Cash collateral posted	$ 43,095	$ 171,581
Letters of credit outstanding	20,000	49,425
Balance sheet offsetting (cash collateral against net derivative positions)	42,355	105,439

There were no letters of credit outstanding related to interest rate swap derivatives as of December 31, 2023 and December 31, 2022.

Certain of Avista Corp.'s derivative instruments contain provisions requiring Avista Corp. to maintain an "investment grade" credit rating from the major credit rating agencies. If Avista Corp.'s credit ratings were to fall below "investment grade," it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing collateralization on derivative instruments in net liability positions.

The following table presents the aggregate fair value of all derivative instruments with credit-risk-related contingent features in a liability position and the amount of additional collateral Avista Corp. could be required to post as of December 31 (dollars in thousands):

	2023
Interest rate swap derivatives	
Liabilities with credit-risk-related contingent features	$ 182
Additional collateral to post	182
Energy commodity derivatives	
Liabilities with credit-risk-related contingent features	$ 18,016
Additional collateral to post	15,125

NOTE 5. JOINTLY OWNED ELECTRIC FACILITIES

The Company has a 15 percent ownership interest in Units 3 and 4 of Colstrip, and provides financing for its ownership interest in the project. Pursuant to the ownership and operating agreements among the co-owners, the Company's share of related fuel costs as well as operating expenses for plant in service are included in the corresponding accounts in the Statements of Income. The Company's share of utility plant in service for Colstrip and accumulated depreciation (inclusive of the ARO assets and accumulated amortization) were as follows as of December 31 (dollars in thousands):

	2023	2022
Utility plant in service	$ 394,398	$ 390,852
Accumulated depreciation	(334,338)	(315,223)

See Note 6 for further discussion of AROs.

While the obligations and liabilities with respect to Colstrip are to be shared among the co-owners on a pro-rata basis, many of the environmental liabilities are joint and several under the law, so that if any co-owner failed to pay its share of such liability, the other co-owners (or any one of them) could be required to pay the defaulting co-owner's share (or the entire liability).

In January 2023, the Company entered into an agreement with NorthWestern to transfer its ownership in Colstrip Units 3 and 4. The Company will retain responsibility for remediation obligations in existence at the time the transaction closes. See further discussion of the transaction within Note 15.

NOTE 6. ASSET RETIREMENT OBLIGATIONS

The Company has recorded liabilities for future AROs to:

- restore coal ash containment ponds and coal holding areas at Colstrip,
- cap a landfill at the Kettle Falls Plant, and
- remove plant and restore the land at the Coyote Springs 2 site at the termination of the land lease.

Due to an inability to estimate a range of settlement dates, the Company cannot estimate a liability for the:

- removal and disposal of certain transmission and distribution assets, and
- abandonment and decommissioning of certain hydroelectric generation and natural gas storage facilities.

In 2015, the EPA issued a final rule regarding CCRs. Colstrip produces this byproduct. The CCR rule has been the subject of ongoing litigation. In August 2018, the D.C. Circuit struck down provisions of the rule. The rule includes technical requirements for CCR landfills and surface impoundments. The Colstrip owners developed a multi-year compliance plan to address the CCR requirements and existing state obligations.

The actual asset retirement costs related to the CCR rule requirements may vary substantially from the estimates used to record the ARO due to the uncertainty and evolving nature of the compliance strategies that will be used and the availability of data used to estimate costs, such as the quantity of coal ash present at certain sites and the volume of fill that will be needed to cap and cover certain impoundments. The Company updates its estimates as new information becomes available. The Company expects to seek recovery of costs related to complying with the CCR rule through the ratemaking process.

In addition to the above, under a 2018 Administrative Order on Consent and ongoing negotiations with the Montana Department of Ecological Quality, the owners of Colstrip are required to provide financial assurance, primarily in the form of surety bonds, to secure each owner's pro-rata share of various anticipated closure and remediation of the ash ponds and coal holding areas. The amount of financial assurance required of each owner may, like the ARO, vary substantially due to the uncertainty and evolving nature of anticipated closure and remediation activities, and as those activities are completed over time.

The following table documents the changes in the Company's asset retirement obligation during the years ended December 31 (dollars in thousands):

	2023	2022
Asset retirement obligation at beginning of year	$ 15,783	$ 17,142
Liabilities incurred	1,927	
Liabilities settled	(232)	(1,964)
Accretion expense	580	605
Asset retirement obligation at end of year	$ 18,058	$ 15,783

NOTE 7. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The Company has a defined benefit pension plan covering the majority of regular full-time non-union employees at Avista Corp. hired prior to January 1, 2014 and regular full-time union employees that were hired prior to January 1, 2024. Employees eligible for the plan continue to accrue benefits. Individual benefits under this plan are based upon the employee's years of service, date of hire and average compensation as specified in the plan. Non-union employees hired on or after January 1, 2014 and union employees hired on or after January 1, 2024 participate in a defined contribution 401(k) plan in lieu of a defined benefit pension plan. The Company's funding policy is to contribute at least the minimum amounts required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts currently deductible for income tax purposes. The Company contributed $10.0 million in cash to the pension plan in 2023, and $42.0 million in 2022. The Company expects to contribute $10.0 million in cash to the pension plan in 2024.

In 2022, the defined benefit pension plan lump sum payments exceeded the annual service and interest costs for the plan. This resulted in a partial settlement of the plan, and the Company recorded a settlement loss of $11.8 million for the previously unrecognized losses in the year ended December 31, 2022. This loss was deferred as a regulatory asset and is being amortized over 12 years in accordance with regulatory accounting orders.

The Company has a SERP providing additional pension benefits to certain executive officers and certain key employees of the Company. The SERP provides benefits to individuals whose benefits under the defined benefit pension plan are reduced due to the application of Section 415 of the Internal Revenue Code of 1986 and the deferral of salary under deferred compensation plans. The liability and expense for this plan are included as pension benefits in the tables included in this Note.

The Company expects benefit payments under the pension plan and the SERP will total (dollars in thousands):

	2024	2025	2026	2027	2028	Total 2029-2033
Expected benefit payments	$ 41,562	$ 42,123	$ 42,941	$ 43,517	$ 44,700	$ 232,345

The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by the plan. In selecting a discount rate, the Company considers yield rates for highly rated corporate bond portfolios with maturities similar to that of the expected term of pension benefits.

The Company provides certain health care and life insurance benefits for eligible retired employees hired prior to January 1, 2014. The Company accrues the estimated cost of postretirement benefit obligations during the years employees provide services. The liability and expense of this plan are included as other postretirement benefits. Non-union employees hired on or after January 1, 2014, will have access to the retiree medical plan upon retirement; however, Avista Corp. will no longer provide a contribution toward their medical premium.

The Company has a Health Reimbursement Arrangement (HRA) to provide employees with tax-advantaged funds to pay for allowable medical expenses upon retirement. The amount earned by the employee is fixed on the retirement date based on the employee's years of service and the ending salary. The liability and expense of the HRA are included as other postretirement benefits.

The Company provides death benefits to beneficiaries of executive officers who die during their term of office or after retirement. Under the plan, an executive officer's designated beneficiary will receive a payment equal to twice the executive officer's annual base salary at the time of death (or if death occurs after retirement, a payment equal to twice the executive officer's total annual pension benefit). The liability and expense for this plan are included as other postretirement benefits.

The Company expects benefit payments under other postretirement benefit plans will total (dollars in thousands):

	2024	2025	2026	2027	2028	Total 2029-2033
Expected benefit payments	$ 7,084	$ 7,266	$ 7,436	$ 7,608	$ 7,822	$ 40,805

The Company expects to contribute $7.1 million to other postretirement benefit plans in 2024. The Company uses a December 31 measurement date for its pension and other postretirement benefit plans.

The following table sets forth the pension and other postretirement benefit plan disclosures as of December 31, 2023 and 2022 and the components of net periodic benefit costs for the years ended December 31, 2023 and 2022 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2023	2022	2023	2022
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 557,709	$ 799,042	$ 115,635	$ 167,598
Service cost	14,350	23,877	2,394	4,369
Interest cost	33,245	26,536	6,766	5,503
Actuarial (gain)/loss	21,373	(204,775)	4,799	(54,120)
Plan change		3,302		
Settlement		(60,206)		
Benefits paid	(41,432)	(30,067)	(7,210)	(7,715)
Benefit obligation as of end of year	$ 585,245	$ 557,709	$ 122,384	$ 115,635
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 540,703	$ 750,963	$ 49,472	$ 59,544
Actual return on plan assets	78,838	(163,866)	8,654	(10,072)
Employer contributions	10,000	42,000		
Settlement		(60,206)		
Benefits paid	(39,558)	(28,188)		
Fair value of plan assets as of end of year	$ 589,983	$ 540,703	$ 58,126	$ 49,472
Funded status	$ 4,738	$ (17,006)	$ (64,258)	$ (66,163)
Amounts recognized in the Balance Sheets:				
Non-current assets	$ 32,997	$ 13,382	$	$
Current liabilities	(2,212)	(1,934)	(652)	(706)
Non-current liabilities	(26,047)	(28,454)	(63,606)	(65,457)
Net amount recognized	$ 4,738	$ (17,006)	$ (64,258)	$ (66,163)
Accumulated pension benefit obligation	$ 514,295	$ 495,654		
Accumulated postretirement benefit obligation:				
For retirees			$ 68,087	$ 61,984
For fully eligible employees			$ 16,054	$ 19,731
For other participants			$ 38,243	$ 33,920
Included in accumulated other comprehensive loss (income) (net of tax):				
Unrecognized prior service cost (credit)	$ 3,717	$ 4,105	$ (1,081)	$ (1,911)
Unrecognized net actuarial loss	69,002	83,794	13,103	13,643
Total	72,719	87,899	12,022	11,732
Less regulatory asset	(71,983)	(85,198)	(12,401)	(12,375)
Accumulated other comprehensive loss for unfunded benefit obligation for pensions and other postretirement benefit plans	$ 736	$ 2,701	$ (379)	$ (643)

	Pension Benefits		Other Post-retirement Benefits	
	2023	2022	2023	2022
Weighted-average assumptions as of December 31:				
Discount rate for benefit obligation	5.86%	6.10%	5.83%	6.10%
Discount rate for annual expense	6.10%	3.39%	6.10%	3.40%
Expected long-term return on plan assets	8.30%	5.80%	7.20%	4.70%
Rate of compensation increase	4.87%	4.69%		
Medical cost trend pre-age 65 - initial			6.50%	6.25%
Medical cost trend pre-age 65 - ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2030	2028
Medical cost trend post-age 65 - initial			6.50%	6.25%
Medical cost trend post-age 65 - ultimate			5.00%	5.00%
Ultimate medical cost trend year post-age 65			2030	2028

	Pension Benefits		Other Post-retirement Benefits	
	2023	2022	2023	2022
Components of net periodic benefit cost:				
Service cost (1)	$ 14,350	$ 23,877	$ 2,394	$ 4,369
Interest cost	33,245	26,536	6,766	5,503
Expected return on plan assets	(43,656)	(43,872)	(3,562)	(2,799)
Amortization of prior service cost (credit)	491	257	(1,050)	(1,050)
Net loss recognition	4,915	4,180	319	3,344
Settlement loss (2)		11,828		
Net periodic benefit cost	$ 9,345	$ 22,806	$ 4,867	$ 9,367

(1)Total service costs in the table above are recorded to the same accounts as labor expense. Labor and benefits expense is recorded to various projects based on whether the work is a capital project or an operating expense. Approximately 40 percent of all labor and benefits is capitalized to utility property and 60 percent is expensed to utility other operating expenses.

(2)The settlement loss was deferred as a regulatory asset and is being amortized over 12 years in accordance with regulatory accounting orders.

Plan Assets

The Finance Committee of the Board of Directors approves investment policies, objectives and strategies that seek an appropriate return for the pension plan and other postretirement benefit plans and reviews and approves changes to the investment and funding policies.

The Company has contracted with investment consultants who are responsible for monitoring the individual investment managers. The investment managers' performance and related individual fund performance is periodically reviewed by an internal benefits committee and by the Finance Committee to monitor compliance with investment policy objectives and strategies.

Pension plan assets are invested in mutual funds, and trusts and partnerships that hold marketable debt and equity securities and real estate. In seeking to obtain a return that aligns with the funded status of the pension plan, the investment consultant recommends allocation percentages by asset classes. These recommendations are reviewed by the internal benefits committee, which then recommends their adoption by the Finance Committee. The Finance Committee has established target investment allocation percentages by asset classes and investment ranges for each asset class. The target investment allocation percentages are typically the midpoint of the established range. The target investment allocation percentages by asset classes are indicated in the table below:

	2023	2022
Equity securities	55%	55%
Debt securities	40%	40%
Real estate	5%	5%

The fair value of pension plan assets invested in debt and equity securities was based primarily on fair value (market prices). The fair value of investment securities traded on a national securities exchange is determined based on the reported last sales price; securities traded in the over-the-counter market are valued at the last reported bid price. Investment securities for which market prices are not readily available or for which market prices do not represent the value at the time of pricing, the investment manager estimates fair value based upon other inputs (including valuations of securities comparable in coupon, rating, maturity and industry).

Pension plan and other postretirement plan assets with fair values are measured using net asset value (NAV) are excluded from the fair value hierarchy and included as reconciling items in the tables below.

The plan's investments in common/collective trusts have redemption limitations that permit quarterly redemptions following notice requirements of 45 to 60 days. Most of the plan's investments in closely held investments and partnership interests have redemption limitations ranging from bi-monthly to semi-annually following redemption notice requirements of 60 to 90 days.

The following table discloses by level within the fair value hierarchy (see Note 13 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2023 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$	$ 6,984	$	$ 6,984
Fixed income securities:				
U.S. government issues		19,293		19,293
Corporate issues		175,460		175,460
International issues		27,052		27,052
Municipal issues		13,772		13,772
Mutual funds:				
U.S. equity securities	169,993			169,993
International equity securities	74,749			74,749
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts: real estate				25,284
Partnership/closely held investments:				
International equity securities				70,652
Real estate				6,744
Total	$ 244,742	$ 242,561	$	$ 589,983

The following table discloses by level within the fair value hierarchy (see Note 13 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2022 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$	$ 5,110	$	$ 5,110
Fixed income securities:				
U.S. government issues		16,732		16,732
Corporate issues		161,180		161,180
International issues		23,108		23,108
Municipal issues		13,427		13,427
Mutual funds:				
U.S. equity securities	154,442			154,442
International equity securities	58,933			58,933
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts: real estate				30,406
Partnership/closely held investments:				
International equity securities				69,792
Real estate				7,573
Total	$ 213,375	$ 219,557	$	$ 540,703

The fair value of other postretirement plan assets invested in debt and equity securities was based primarily on market prices. The fair value of investment securities traded on a national securities exchange is determined based on the last reported sales price; securities traded in the over-the-counter market are valued at the last reported bid price. For investment securities for which market prices are not readily available, the investment manager determines fair value based upon other inputs (including valuations of securities comparable in coupon, rating, maturity and industry). The target asset allocation was 60 percent equity securities and 40 percent debt securities in both 2023 and 2022.

The fair value of other postretirement plan assets was determined to be $58.1 million and $49.5 million as of December 31, 2023 and 2022, respectively. The assets consist of a balanced index mutual fund, which is a single mutual fund that includes a percentage of U.S. equity and fixed income securities and International equity and fixed income securities. This mutual fund is classified as Level 1 in the fair value hierarchy (see Note 13 for a description of the fair value hierarchy).

401(k) Plans and Executive Deferral Plan

Avista Corp. has a salary deferral 401(k) plan that is a defined contribution plan and covers substantially all employees. Employees can make contributions to their respective accounts in the plans on a pre-tax basis up to the maximum amount permitted by law. The Company matches a portion of the salary deferred by each participant according to the schedule in the respective plan.

Employer matching contributions were as follows for the years ended December 31 (dollars in thousands):

	2023	2022
Employer 401(k) matching contributions	$ 15,022	$ 13,258

The Company has an Executive Deferral Plan. This plan allows executive officers and other key employees the opportunity to defer until the earlier of their retirement, termination, disability or death, up to 75 percent of their base salary and/or up to 100 percent of their incentive payments. Deferred compensation funds are held by the Company in a Rabbi Trust.

There were deferred compensation assets corresponding deferred compensation liabilities on the Balance Sheets of the following amounts as of December 31 (dollars in thousands):

		2023		2022
Deferred compensation assets and liabilities	$	7,794	$	7,541

NOTE 8. ACCOUNTING FOR INCOME TAXES

The realization of deferred income tax assets is dependent upon the ability to generate taxable income in future periods. The Company evaluated available evidence supporting the realization of its deferred income tax assets and determined it is more likely than not that deferred income tax assets will be realized.

As of December 31, 2023, the Company had $17.3 million of state tax credit carryforwards. Of the total amount, the Company believes that it is more likely than not that it will only be able to utilize $6.8 million of the state tax credits. As such, the Company has recorded a valuation allowance of $10.5 million against the state tax credit carryforwards and reflected the net amount of $6.8 million as an asset as of December 31, 2023. State tax credits expire from 2024 to 2037.

Status of Internal Revenue Service (IRS) and State Examinations

The Company and its eligible subsidiaries file consolidated federal income tax returns. All tax years after 2018 are open for an IRS tax examination. The IRS is reviewing tax year 2019.

The Company files state income tax returns in certain jurisdictions, including Idaho, Oregon, Montana and Alaska. Subsidiaries are charged or credited with the tax effects of their operations on a stand-alone basis.

All tax years after 2019 are open for examination in Idaho, Oregon, Montana and Alaska.

The Company believes open tax years for federal or state income taxes will not result in adjustments that would be significant to the financial statements.

NOTE 9. ENERGY PURCHASE CONTRACTS

Avista Corp. has contracts for the purchase of fuel for thermal generation, natural gas for resale and various agreements for the purchase or exchange of electric energy with other entities. The remaining term of the contracts range from one month to twenty-five years.

Total expenses for power purchased, natural gas purchased, fuel for generation and other fuel costs, which are included in utility resource costs in the Statements of Income, were as follows for the years ended December 31 (dollars in thousands):

		2023		2022
Utility power resources	$	607,155	$	660,967

The following table details Avista Corp.'s future contractual commitments for power resources (including transmission contracts) and natural gas resources (including transportation contracts) (dollars in thousands):

		2024		2025		2026		2027		2028		Thereafter		Total
Power resources	$	336,766	$	293,389	$	266,251	$	235,751	$	234,756	$	2,245,762	$	3,612,675
Natural gas resources		122,241		81,141		46,033		41,708		41,168		280,562		612,853
Total	$	459,007	$	374,530	$	312,284	$	277,459	$	275,924	$	2,526,324	$	4,225,528

These energy purchase contracts were entered into as part of Avista Corp.'s obligation to serve its retail electric and natural gas customers' energy requirements, including contracts entered into for resource optimization. These costs are recovered either through base retail rates or adjustments to retail rates as part of the power and natural gas cost deferral and recovery mechanisms.

The future contractual commitments for power resources include fixed contractual amounts related to the Company's contracts with Public Utility Districts (PUDs) to purchase portions of the output of certain generating facilities. Although Avista Corp. has no investment in the PUD generating facilities, the contracts obligate Avista Corp. to pay certain minimum amounts whether or not the facilities are operating. The cost of power obtained under the contracts, including payments made when a facility is not operating, is included in utility resource costs in the Statements of Income. The contractual amounts included above consist of Avista Corp.'s share of existing debt service cost and its proportionate share of the variable operating expenses of these projects. The minimum amounts payable under these contracts are based in part on the proportionate share of the debt service requirements of the PUD's revenue bonds for which the Company is indirectly responsible. The Company's total future debt service obligation associated with the revenue bonds outstanding at December 31, 2023 (principal and interest) was $275.1 million.

In addition, Avista Corp. has operating agreements, settlements and other contractual obligations related to its generating facilities and transmission and distribution services. The expenses associated with these agreements are reflected as other operating expenses in the Statements of Income. The following table details future contractual commitments under these agreements (dollars in thousands):

		2024		2025		2026		2027		2028		Thereafter		Total
Contractual obligations	$	39,156	$	40,226	$	18,630	$	19,085	$	9,390	$	177,553	$	304,040

NOTE 10. NOTES PAYABLE

Lines of Credit

Avista Corp. has a committed line of credit in the total amount of $500.0 million, with expiration date of June 2028. The Company has the option to extend for two additional one year periods (subject to customary conditions). In June 2023, the then-existing agreement was amended to increase the capacity of the committed line of credit from $400.0 million to $500.0 million, extend the expiration date, and replace the London Interbank Offered Rate (LIBOR) provisions with Secured Overnight Financing Rate (SOFR) provisions. The committed line of credit is secured by non-transferable first mortgage bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit.

Balances outstanding and interest rates of borrowings (excluding letters of credit) under the Company's revolving committed line of credit were as follows as of December 31 (dollars in thousands):

		2023		2022
Balance outstanding at end of period	$	349,000	$	313,000
Letters of credit outstanding at end of period		4,700		35,563
Average interest rate at end of period		6.46%		5.31%

In December 2022, Avista Corp. entered into an additional revolving credit agreement in the amount of $100.0 million. As of December 31, 2022, the Company did not have any outstanding borrowings under this agreement. The agreement was terminated in June 2023.

As of December 31, 2023 and 2022, the borrowings outstanding under Avista Corp.'s committed lines of credit were classified as short-term borrowings on the Balance Sheets.

2022 Term Loan

In December 2022, the Company entered into a term loan agreement in the amount of $150.0 million with a maturity date of March 30, 2023. The Company borrowed the entire $150.0 million available under the agreement in 2022 and repaid the entire outstanding balance in March 2023. The borrowings outstanding under this agreement were classified as short-term borrowings on the Balance Sheets.

2022 Letter of Credit Facility

In December 2022, the Company entered into a continuing letter of credit agreement in the aggregate amount of $50.0 million. Either party may terminate the agreement at any time.

The Company had $20.0 million and $18.5 million in letters of credit outstanding under this agreement as of December 31, 2023 and December 31, 2022, respectively. Letters of credit are not reflected on the Balance Sheets. If a letter of credit were drawn upon by the holder, we would have an immediate obligation to reimburse the bank that issued that letter.

Covenants and Default Provisions

The short-term borrowing agreements contain customary covenants and default provisions, including a change in control (as defined in the agreements). The events of default under each of the credit facilities also include a cross default from other indebtedness (as defined) and in some cases other obligations. Most of the short-term borrowing agreement also include a covenant which does not permit the ratio of "total debt" to "total capitalization" of Avista Corp. to be greater than 65 percent at any time. As of December 31, 2023, the

Company complied with this covenant.

NOTE 11. BONDS

The following details long-term debt outstanding as of December 31 (dollars in thousands):

Maturity Year	Description	Interest Rate	2023	2022
Avista Corp. Secured Long-Term Debt				
2023	Secured Medium-Term Notes	7.18%-7.54%		13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (1)	(1)	66,700	66,700
2034	Secured Pollution Control Bonds (1)	(1)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
2040	First Mortgage Bonds	5.55%	35,000	35,000
2041	First Mortgage Bonds	4.45%	85,000	85,000
2044	First Mortgage Bonds	4.11%	60,000	60,000
2045	First Mortgage Bonds	4.37%	100,000	100,000
2047	First Mortgage Bonds	4.23%	80,000	80,000
2047	First Mortgage Bonds	3.91%	90,000	90,000
2048	First Mortgage Bonds	4.35%	375,000	375,000
2049	First Mortgage Bonds	3.43%	180,000	180,000
2050	First Mortgage Bonds	3.07%	165,000	165,000
2051	First Mortgage Bonds	3.54%	175,000	175,000
2051	First Mortgage Bonds	2.90%	140,000	140,000
2052	First Mortgage Bonds	4.00%	400,000	400,000
2053	First Mortgage Bonds (2)	5.66%	250,000	
	Total Avista Corp. secured long-term debt		2,543,700	2,307,200
	Secured Pollution Control Bonds held by Avista Corporation (1)		(83,700)	(83,700)
	Total long-term debt		$ 2,460,000	$ 2,223,500

(1)In December 2010, $66.7 million and $17.0 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) due in 2032 and 2034, respectively, which had been held by Avista Corp. since 2008 and 2009, respectively, were refunded by new variable rate bond issues. The new bonds were not offered to the public and were purchased by Avista Corp. due to market conditions. The Company can remarket these bonds to unaffiliated investors at a later date, subject to market conditions. So long as Avista Corp. is the holder of these bonds, the bonds are not reflected as an asset or a liability on the Balance Sheets. In April 2024, the Company remarketed these bonds. See Note 18 for further discussion.

(2)In March 2023, the Company issued and sold $250.0 million of 5.66 percent first mortgage bonds due in 2053 with institutional investors in the private placement market. A portion of the net proceeds from the sale of these bonds was used for the construction or improvement of utility facilities, and a portion was used to refinance existing indebtedness, including the repayment of Avista Corp.'s $150.0 million term loan. In connection with the pricing of the first mortgage bonds in March 2023, the Company cash settled four interest rate swap derivatives (notional aggregate amount of $40.0 million) and received a net amount of $7.5 million. See Note 4 for a discussion of interest rate swap derivatives.

The following table details future long-term debt maturities including advances from associated affiliates (see Note 12) (dollars in thousands):

	2024	2025	2026	2027	2028	Thereafter	Total
Debt maturities	$ 15,000	$	$	$	$ 25,000	$ 2,561,547	$ 2,601,547

Substantially all of Avista Corp's owned properties are subject to the lien of their respective mortgage indentures. Under the Mortgages and Deeds of Trust (Mortgages) securing their first mortgage bonds (including secured medium-term notes), Avista Corp. may issue additional first mortgage bonds under their specific mortgage in an aggregate principal amount equal to the sum of:

- 66-2/3 percent of the cost or fair value to the Company (whichever is lower) of property additions of that entity which have not previously been made the basis of any application under that entity's Mortgage, or
- an equal principal amount of retired first mortgage bonds of that entity which have not previously been made the basis of any application under that entity's Mortgage, or
- deposit of cash.

Avista Corp. may not individually issue any additional first mortgage bonds (with certain exceptions in the case of bonds issued on the basis of retired bonds) unless the particular entity issuing the bonds has "net earnings" (as defined in that entity's Mortgage) for any period of 12 consecutive calendar months out of the preceding 18 calendar months that were at least twice the annual interest requirements on all mortgage securities at the time outstanding, including the first mortgage bonds to be issued, and on all indebtedness of prior rank. As of December 31, 2023, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.2 billion in an aggregate principal amount of additional first mortgage bonds at an assumed interest rate of 8 percent.

NOTE 12. ADVANCES FROM ASSOCIATED COMPANIES

In 1997, the Company issued Floating Rate Junior Subordinated Deferrable Interest Debentures, Series B, with a principal amount of $51.5 million to Avista Capital II, an affiliated business trust formed by the Company. Avista Capital II issued $50.0 million of Preferred Trust Securities with a floating distribution rate of LIBOR plus 0.875 percent, calculated and reset quarterly. Effective on July 3, 2023, the reference to LIBOR in the formulation for the distribution rate on these securities was replaced, by operation of law, with three-month CME Term SOFR, as calculated and published by CME Group Benchmark Administration, Ltd. (a successor administrator), plus a tenor spread adjustment of 0.26 percent. Accordingly, the distribution rate on the Preferred Trust Securities is now three-month CME Term SOFR plus 1.137 percent.

The distribution rates paid were as follows during the years ended December 31:

	2023	2022	2021
Low distribution rate	5.64%	1.05%	0.99%
High distribution rate	6.55%	5.64%	1.10%
Distribution rate at the end of the year	6.51%	5.64%	1.05%

Concurrent with the issuance of the Preferred Trust Securities, Avista Capital II issued $1.5 million of Common Trust Securities to the Company. These Preferred Trust Securities may be redeemed at the option of Avista Capital II at any time and mature on June 1, 2037. In December 2000, the Company purchased $10.0 million of these Preferred Trust Securities.

The Company owns 100 percent of Avista Capital II and has solely and unconditionally guaranteed the payment of distributions on, and redemption price and liquidation amount for, the Preferred Trust Securities to the extent Avista Capital II has funds available for such payments from the respective debt securities. Upon maturity or prior redemption of such debt securities, the Preferred Trust Securities will be mandatorily redeemed.

NOTE 13. FAIR VALUE

The carrying values of cash and cash equivalents, special deposits, accounts and notes receivable, accounts payable and notes payable are reasonable estimates of their fair values. Bonds and advances from associated companies are reported at carrying value on the Balance Sheets.

The fair value hierarchy prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to fair values derived from unobservable inputs (Level 3 measurements).

The three levels of the fair value hierarchy are defined as follows:

Level 1 - Quoted prices are available in active markets for identical assets or liabilities. Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 - Pricing inputs are other than quoted prices in active markets included in Level 1, but which are either directly or indirectly observable as of the reporting date. Level 2 includes financial instruments valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Level 3 - Pricing inputs include significant inputs generally unobservable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values incorporates various factors that not only include the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit), but also the impact of Avista Corp.'s nonperformance risk on its liabilities.

The following table sets forth the carrying value and estimated fair value of the Company's financial instruments not reported at estimated fair value on the Balance Sheets as of December 31 (dollars in thousands):

	2023		2022	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Bonds (Level 2)	$ 1,100,000	$ 968,893	$ 1,113,500	$ 966,881
Bonds (Level 3)	1,360,000	1,088,500	1,110,000	805,802
Advances from associated companies (Level 3)	51,547	46,098	51,547	42,836

These estimates of fair value of long-term debt and long-term debt to affiliated trusts were primarily based on available market information, which generally consists of estimated market prices from third party brokers for debt with similar risk and terms. The price ranges obtained from the third party brokers consisted of par values of 62.73 to 107.245, where a par value of 100.00 represents the carrying value recorded on the Balance Sheets. Level 2 long-term debt represents publicly issued bonds with quoted market prices; however, due to their limited trading activity, they are classified as Level 2 because brokers must generate quotes and make estimates using comparable debt with similar risk and terms if there is no trading activity near a period end. Level 3 long-term debt consists of private placement bonds and debt to affiliated trusts, which typically have no secondary trading activity. Fair values in Level 3 are estimated based on market prices from third party brokers using secondary market quotes for debt with similar risk and terms to generate quotes for Avista Corp. bonds.

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Balance Sheets as of December 31, 2023 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2023					
Assets:					
Energy commodity derivatives (2)	$ —	$ 30,954	$ —	$ (22,802)	$ 8,152
Foreign currency exchange derivatives	—	2	—	—	2
Interest rate swap derivatives	—	3,667	—	—	3,667
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities	1,117	—	—	—	1,117
Equity securities	6,524	—	—	—	6,524
Total	$ 7,641	$ 34,623	$ —	$ (22,802)	$ 19,462
Liabilities:					
Energy commodity derivatives (2)	$ —	$ 91,844	$ 8,250	$ (65,157)	$ 34,937
Interest rate swap derivatives	—	182	—	—	182
Total	$ —	$ 92,026	$ 8,250	$ (65,157)	$ 35,119

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Balance Sheets as of December 31, 2022 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2022					
Assets:					
Energy commodity derivatives (2)	$ —	$ 146,232	$ 288	$ (136,605)	$ 9,915
Foreign currency exchange derivatives	—	43	—	—	43
Interest rate swap derivatives	—	11,184	—	—	11,184
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities	1,267	—	—	—	1,267
Equity securities	6,132	—	—	—	6,132
Total	$ 7,399	$ 157,459	$ 288	$ (136,605)	$ 28,541
Liabilities:					
Energy commodity derivatives (2)	$ —	$ 258,769	$ 18,022	$ (242,044)	$ 34,747
Foreign currency exchange derivatives	—	3	—	—	3
Interest rate swap derivatives	—	52	—	—	52
Total	$ —	$ 258,824	$ 18,022	$ (242,044)	$ 34,802

(1)The Company is permitted to net derivative assets and derivative liabilities with the same counterparty when a legally enforceable master netting agreement exists. In addition, the Company nets derivative assets and derivative liabilities against payables and receivables for cash collateral held or placed with these same counterparties.

(2)The Level 3 energy commodity derivative balances are associated with natural gas exchange agreements.

The difference between the amount of derivative assets and liabilities disclosed in respective levels in the table above and the amount of derivative assets and liabilities disclosed on the Balance Sheets is due to netting arrangements with certain counterparties. See Note 4 for additional discussion of derivative netting.

To establish fair value for energy commodity derivatives, the Company uses quoted market prices and forward price curves to estimate the fair value of energy commodity derivative instruments included in Level 2. In particular, electric derivative valuations are performed using market quotes, adjusted for periods in between quotable periods. Natural gas derivative valuations are estimated using New York Mercantile Exchange pricing for similar instruments, adjusted for basin differences, using market quotes. Where observable inputs are available for substantially the full term of the contract, the derivative asset or liability is included in Level 2.

To establish fair values for interest rate swap derivatives, the Company uses forward market curves for interest rates for the term of the swaps and discounts the cash flows back to present value using an appropriate discount rate. The discount rate is calculated by third party brokers according to the terms of the swap derivatives and evaluated by the Company for reasonableness, with consideration given to the potential non-performance risk by the Company. Future cash flows of the interest rate swap derivatives are equal to the fixed interest rate in the swap compared to the floating market interest rate multiplied by the notional amount for each period.

To establish fair value for foreign currency derivatives, the Company uses forward market curves for Canadian dollars against the U.S. dollar and multiplies the difference between the locked-in price and the market price by the notional amount of the derivative. Forward foreign currency market curves are provided by third party brokers. The Company's credit spread is factored into the locked-in price of the foreign exchange contracts.

Deferred compensation assets and liabilities represent funds held by the Company in a Rabbi Trust for an executive deferral plan. These funds consist of actively traded equity and bond funds with quoted prices in active markets.

Level 3 Fair Value

Natural Gas Exchange Agreement

For the natural gas commodity exchange agreement, the Company uses the same Level 2 brokered quotes described above; however, the Company also estimates the purchase and sales volumes (within contractual limits) as well as the timing of those transactions. Changing the timing of volume estimates changes the timing of purchases and sales, impacting which brokered quote is used. Because the brokered quotes can vary significantly from period to period, the unobservable estimates of the timing and volume of transactions can have a significant impact on the calculated fair value. The Company estimates volumes and timing of transactions based on a most likely scenario using historical data. Historically, the timing and volume of transactions have not been highly correlated with market prices and market volatility.

The following table presents the quantitative information which was used to estimate the fair values of the Level 3 assets and liabilities above as of December 31, 2023 (dollars in thousands):

	Fair Value (Net) at December 31, 2023		Valuation Technique	Unobservable Input	Range
Natural gas exchange	$	(8,250)	Internally derived weighted average cost of gas	Forward purchase prices	$1.64 - $3.07/mmBTU $2.40 Weighted Average
				Forward sales prices	$2.13 - $8.99/mmBTU $5.45 Weighted Average
				Purchase volumes	300,000 - 310,000 mmBTUs
				Sales volumes	75,000 - 310,000 mmBTUs

The valuation methods, significant inputs and resulting fair values described above were developed by the Company's management and are reviewed on at least a quarterly basis to ensure they provide a reasonable estimate of fair value each reporting period.

The following table presents activity for assets and liabilities measured at fair value using significant unobservable inputs (Level 3) for the years ended December 31 (dollars in thousands):

		Natural Gas Exchange Agreement (1)
Year ended December 31, 2023:		
Balance as of January 1, 2023	$	(17,734)
Total gains or (losses) (realized/unrealized):		
Included in regulatory assets		9,238
Settlements		246
Ending balance as of December 31, 2023	$	(8,250)
Year ended December 31, 2022:		
Balance as of January 1, 2022	$	(7,771)
Total gains or (losses) (realized/unrealized):		
Included in regulatory assets		(4,740)
Settlements		(5,223)
Ending balance as of December 31, 2022	$	(17,734)

(1)There were no purchases, issuances or transfers from other categories of derivatives instruments during the periods presented in the table above.

NOTE 14. COMMON STOCK

The payment of dividends on common stock could be limited by:

- certain covenants applicable to preferred stock (when outstanding) contained in the Company's Restated Articles of Incorporation, as amended (currently there are no preferred shares outstanding),
- certain covenants applicable to the Company's outstanding long-term debt and committed line of credit agreements,
- the hydroelectric licensing requirements of section 10(d) of the FPA (see Note 1), and
- certain requirements under the OPUC approval of the AERC acquisition in 2014. The OPUC's AERC acquisition order requires Avista Corp. to maintain a capital structure of no less than 35 percent common equity (inclusive of short-term debt). This limitation may be revised upon request by the Company with approval from the OPUC.

The requirements of the OPUC approval of the AERC acquisition are the most restrictive. Under the OPUC restriction, the amount available for dividends at December 31, 2023 was $295.6 million.

The Company has 10 million authorized shares of preferred stock. The Company did not have preferred stock outstanding as of December 31, 2023 and 2022.

Common Stock Issuances

The Company issued common stock for total net proceeds of $112.3 million in 2023. Most of these issuances came through the Company's sales agency agreements under which the sales agents may offer and sell new shares of common stock from time to time. In 2023, 3.0 million shares were issued under these agreements resulting in total net proceeds of $111.8 million.

NOTE 15. COMMITMENTS AND CONTINGENCIES

In the course of its business, the Company becomes involved in various claims, controversies, disputes and other contingent matters, including the items described in this Note. Some of these claims, controversies, disputes and other contingent matters involve litigation or other contested proceedings. For all such matters, the Company will vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the ultimate outcome of any matter because litigation and other contested proceedings are subject to numerous uncertainties. For matters affecting Avista Corp.'s operations, the Company intends to seek, to the extent appropriate, recovery of incurred costs through the ratemaking process.

Collective Bargaining Agreements

The Company's collective bargaining agreement with the IBEW represents 36 percent of all Avista Corp's employees. The Company's largest represented group, representing approximately 90 percent of Avista Corp.'s bargaining unit employees in Washington and Idaho, are covered under a four year agreement which expires in March 2025.

The current agreement includes a clause to negotiate wages in effect for the last year of the agreement. The Company is in the process of negotiating these wages. There is a risk that if an agreement on wages is not reached, the employees subject to the agreement could strike. Given the number of employees that are covered by the collective bargaining agreement, a strike could result in disruptions to the Company's operations. However, the Company believes the possibility of this occurring is remote.

Boyds Fire (State of Washington Department of Natural Resources v. Avista)

In August 2019, the Company was served with a complaint, captioned "State of Washington Department of Natural Resources v. Avista Corporation," seeking recovery of up to $4.4 million for fire suppression and investigation costs and related expenses incurred in connection with a wildfire that occurred in Ferry County, Washington, in August 2018. Specifically, the complaint alleges the fire, which became known as the "Boyds Fire," was caused by a dead ponderosa pine tree falling into an overhead distribution line, and that Avista Corp., along with its independent vegetation management contractors Asplundh Tree Company and CN Utility Consulting, were negligent in failing to identify and remove the tree before it came into contact with the line. Avista Corp. disputes that it was negligent in failing to identify and remove the tree in question. Additional lawsuits were subsequently filed by private landowners seeking property damages, and holders of insurance subrogation claims seeking recovery of insurance proceeds paid.

The lawsuits were filed in the Superior Court of Ferry County, Washington. The Company continues to vigorously defend itself in the litigation. However, at this time the Company is unable to predict the likelihood of an adverse outcome or estimate a range of potential loss in the event of such an outcome.

Road 11 Fire

In April 2022, Avista Corp. received a notice of claim from property owners seeking damages of $5 million in connection with a fire that occurred in Douglas County, Washington, in July 2020. In June 2022, those claimants filed suit in the Superior Court of Douglas County, Washington, seeking unspecified damages. The fire, which was designated as the "Road 11 Fire," occurred in the vicinity of an Avista Corp. 115kv line, resulting in damage to three overhead transmission structures. The fire occurred during a high wind event and grew to 10,000 acres before being contained. The Company disputes that it is liable for the fire and will vigorously defend itself in the pending legal proceeding; however, at this time the Company is unable to predict the likelihood of an adverse outcome or estimate a range of potential loss in the event of such an outcome.

Labor Day 2020 Windstorm

General

In September 2020, a severe windstorm occurred in eastern Washington and northern Idaho. The extreme weather event resulted in customer outages and multiple wildfires in the region.

The Company has become aware of instances where, during the storm, otherwise healthy trees and limbs, located in areas outside its maintenance right-of-way, broke under the extraordinary wind conditions and caused damage to its energy delivery system at or near what is believed to be the potential area of origin of a wildfire. However, the Company's investigations found no evidence of negligence with respect to any of those fires. Consistent with that conclusion, the statute of limitations with respect to the claims arising out of the Labor Day 2020 Windstorm has now passed and, except with respect to the Babb Road Fire discussed below, no legal action has been commenced.

Babb Road Fire

In May 2021 the Company learned the Washington Department of Natural Resources (DNR) had completed its investigation and issued a report on the Babb Road Fire. The Babb Road fire covered approximately 15,000 acres and destroyed approximately 220 structures. There are no reports of personal injury or death resulting from the fire.

The DNR report concluded, among other things, that

- the fire was ignited when a branch of a multi-dominant Ponderosa Pine tree was broken off by the wind and fell on an Avista Corp. distribution line;
- the tree was located approximately 30 feet from the center of Avista Corp.'s distribution line and approximately 20 feet beyond Avista Corp.'s right-of-way;
- the tree showed some evidence of insect damage, damage at the top of the tree from porcupines, a small area of scarring where a lateral branch/leader (LBL) had broken off in the past, and some past signs of Gall Rust disease.

The DNR report concluded as follows: "It is my opinion that because of the unusual configuration of the tree, and its proximity to the powerline, a closer inspection was warranted. A nearer inspection of the tree should have revealed the cut LBL ends and its previous failure, and necessitated determination of the failure potential of the adjacent LBL, implicated in starting the Babb Road Fire."

The DNR report acknowledged that, other than the multi-dominant nature of the tree, the conditions mentioned above would not have been easily visible without close-up inspection of, or cutting into, the tree. The report also acknowledged that, while the presence of multiple tops would have been visible from the nearby roadway, the tree did not fail at a v-fork due to the presence of multiple tops. The Company contends that applicable inspection standards did not require a closer inspection of the otherwise healthy tree, nor was the Company negligent with respect to its maintenance, inspection or vegetation management practices.

Eleven lawsuits have been filed in connection with the Babb Road fire. Asplundh Tree Company and CNUC Utility Consulting, which both perform vegetation management services as independent contractors to the Company, are also named as defendants in each of the lawsuits. The lawsuits include six subrogation actions filed by insurance companies seeking to recover approximately $23 million purportedly paid to insureds to date; four actions on behalf of individual plaintiffs seeking unspecified damages; and a class action lawsuit seeking unspecified damages. All proceedings, except for one action filed on September 1, 2023 on behalf of three individual plaintiffs, have been consolidated in the Superior Court of Spokane County Washington under the lead action *Blakeley v. Avista Corporation et al.*, and variously assert causes of action for negligence, private nuisance, and trespass (the Blakeley Proceeding).

In November 2023, all parties to the Blakeley Proceeding agreed to a stipulated order, which was presented to and entered by the Superior Court of Spokane County, Washington. The order consolidates the Blakeley Proceeding for trial (in addition to discovery and pre-trial proceedings) and bifurcates the trial into liability and damages phases, such that the initial trial in the case will focus solely on whether the defendants are legally responsible for the Babb Road Fire. A trial date on the liability phase has been set for May 5, 2025.

In addition, the order memorializes the plaintiffs' agreement to voluntarily dismiss all claims asserting inverse condemnation as a theory of liability without prejudice to their ability to seek permission from the Court to refile those claims at a later date if there is good cause to do so. The individual action that was not consolidated into the Blakeley Proceeding does not include claims for inverse condemnation. The parties to the Blakeley Proceeding agreed to a preliminary mediation no later than 60 days prior to the liability trial, and, if there is a trial following that mediation and if the jury returns a verdict in the plaintiffs' favor in the liability trial, a second mediation within 90 days following the verdict focusing on damages. Finally, the plaintiffs agreed to complete a damages questionnaire identifying all claimed damages being sought in connection with the litigation.

The Company will vigorously defend itself in the legal proceedings; however, at this time the Company is unable to predict the likelihood of an adverse outcome or estimate a range of potential loss in the event of such an outcome.

Orofino Fire

In August 2023, a fire subsequently referred to as the "Hospital Fire", started in windy conditions near Orofino, Idaho, burning 53 acres and seven primary residences, as well as several outbuildings. The Idaho Department of Lands investigated and has issued a report in which it concluded the fire was caused by an electrical fault igniting three separate spots which then spread uphill. The Company has a distribution line in the area near the ignition point. While the Company has not yet completed its own investigation, the Company has to date found no evidence suggesting negligence on its part. Except for one claim for damage to personal property, the Company has not, at this time, received any claims in connection with the fire. The Company will vigorously defend itself in the event any such claims are asserted; however, at this time, it is unable to estimate the likelihood of an adverse outcome nor the amount or range of a potential loss in the event of an adverse outcome.

Colstrip

Colstrip Owners Arbitration and Litigation

Colstrip Units 3 and 4 are owned by the Company, PacifiCorp, Portland General Electric (PGE), and Puget Sound Energy (PSE) (collectively, the "Western Co-Owners"), as well as NorthWestern and Talen Montana, LLC (Talen), as tenants in common under an Ownership and Operating Agreement, dated May 6, 1981, as amended (O&O Agreement), in the percentages set forth below:

Co-Owner	Unit 3	Unit 4
Avista	15%	15%
PacifiCorp	10%	10%
PGE	20%	20%
PSE	25%	25%
NorthWestern		30%
Talen	30%	

Colstrip Units 1 and 2, owned by PSE and Talen, were shut down in 2020 and are in the process of being decommissioned. The co-owners of Units 3 and 4 also own undivided interests in facilities common to both Units 3 and 4, as well as in certain facilities common to all four Colstrip units.

The Washington Clean Energy Transformation Act (CETA), among other things, imposes deadlines by which each electric utility must eliminate from its electricity rates in Washington the costs and benefits associated with coal-fired resources, such as Colstrip. The practical impact of CETA is electricity from such resources, including Colstrip, may no longer be delivered to Washington retail customers after 2025.

The co-owners of Colstrip Units 3 and 4 have differing needs for the generating capacity of these units. Accordingly, certain business disagreements have arisen among the co-owners, including, disagreements as to the requirements for shutting down these units. NorthWestern has initiated arbitration pursuant to the O&O Agreement to resolve these business disagreements, and two actions have been initiated to compel arbitration of those disputes: one by Talen in the Montana Thirteenth Judicial District Court for Yellowstone County, and one by the Western Co-Owners, which is pending in Montana Federal District Court. In light of the ownership transfer agreements discussed below, the Colstrip owners agreed to stay both the litigation and the arbitration through March 2024. On April 1, 2024, the agreement to stay lapsed and at least one owner, Puget Sound Energy, has indicated they wish to resume the arbitration proceeding.

Agreement Between Talen and Puget Sound Energy

In September 2022, PSE and Talen entered into an agreement through which PSE has agreed to transfer its 25 percent ownership in Colstrip Units 3 and 4 to Talen at the end of 2025. The terms and conditions of the agreement are similar in most respects to the NorthWestern transaction discussed below.

Agreement Between Avista and NorthWestern

In January 2023, the Company entered into an agreement with NorthWestern under which, subject to the terms and conditions specified in the agreement, the Company will transfer its 15 percent ownership in Colstrip Units 3 and 4 to NorthWestern. There is no monetary exchange included in the transaction. The transaction is scheduled to close on December 31, 2025 or such other date as the parties mutually agree upon.

Under the agreement, the Company will remain obligated through the close of the transaction to pay its share of (i) operating expenses, (ii) capital expenditures, but not in excess of the portion allocable pro rata to the portion of useful life (through 2030) expired through the close of the transaction, and (iii) except for certain costs relating to post-closing activities, site remediation expenses. In addition, the Company would enter into an agreement under which it would retain its voting rights with respect to decisions relating to remediation.

The Company will retain its Colstrip transmission system assets, which are excluded from the transaction.

Under the Colstrip O&O Agreement, each of the other owners of Colstrip has a 90-day period in which to evaluate the transaction and determine whether to exercise their respective rights of first refusal as to a portion of the generation being turned over to NorthWestern. That period has now expired, and no owners have exercised a right to first refusal.

The transaction is subject to the satisfaction of customary closing conditions including the receipt of any required regulatory approvals, as well as NorthWestern's ability to enter into a new coal supply agreement by December 31, 2024.

The Company does not expect this transaction to have a direct material impact on its financial results.

Burnett et al. v. Talen et al.

Multiple property owners initiated a legal proceeding (titled Burnett et al. v. Talen et al.) in the Montana District Court for Rosebud County against Talen, PSE, PacifiCorp, PGE, Avista Corp., NorthWestern, and Westmoreland Rosebud Mining. The plaintiffs allege a failure to contain coal dust in connection with the operation of Colstrip, and seek unspecified damages. The Company will vigorously defend itself in the litigation, but at this time is unable to predict the outcome, nor an amount or range of potential impact in the event of an outcome adverse to the Company's interests.

Westmoreland Mine Permits

Two lawsuits have been commenced by the Montana Environmental Information Center and others, challenging certain permits relating to the operation of the Westmoreland Rosebud Mine, which provides coal to Colstrip. In the first, the Montana District Court for Rosebud County issued an order vacating a permit for one area of the mine, which decision was subsequently upheld by the Montana Supreme Court. In the second, the Montana Federal District Court vacated a decision by the federal Office of Surface Mining Reclamation and Enforcement, a branch of the United States Department of Interior, approving expansion of the mine into a new area, pending further analysis of potential environmental impact. An initial appeal of that decision to the Ninth Circuit was dismissed for lack of jurisdiction, pending further proceedings before the Department of the Interior. Avista Corp. is not a party to either of these proceedings, but continues to monitor the progress of both issues and assess the impact, if any, of the proceedings on Westmoreland's ability to meet its contractual coal supply obligations.

National Park Service (NPS) - Natural and Cultural Damage Claim

In March 2017, the Company accessed property managed by the National Park Service (NPS) to prevent the imminent failure of a power pole surrounded by flood water in the Spokane River. The Company voluntarily reported its actions to the NPS several days later. Thereafter, in March 2018, the NPS notified the Company that it might seek recovery for unspecified costs and damages allegedly caused during the incident pursuant to the System Unit Resource Protection Act (SURPA), 54 U.S.C. 100721 et seq. In January 2021, the United States Department of Justice (DOJ) requested the Company and the DOJ renew discussions relating to the matter. In July 2021, the DOJ communicated that it may seek damages of approximately $2 million in connection with the incident for alleged damage to "natural and cultural resources". In addition, the DOJ indicated that it may seek treble damages under the SURPA and state law, bringing its total potential claim to approximately $6 million.

The Company disputes the position taken by the DOJ with respect to the incident, as well as the nature and extent of the DOJ's alleged damages, and will vigorously defend itself in any litigation that may arise with respect to the matter. The Company and the DOJ have engaged in discussions to understand their respective positions and determine whether a resolution of the dispute may be possible. However, the Company cannot predict the outcome of the matter.

Rathdrum, Idaho Natural Gas Incident

In October 2021, there was an incident in Rathdrum, Idaho involving the Company's natural gas infrastructure. The incident occurred after a third party damaged those facilities during excavation work. The incident resulted in a fire which destroyed one residence and resulted in minor injuries to the occupants. In January 2023, the Company was served with a lawsuit filed in the District Court of Kootenai County, Idaho by one property owner, seeking unspecified damages. In February 2024, the Company became aware of a second lawsuit filed by the owners of the adjacent property, seeking damages for personal injury and emotional distress from having witnessed the incident. The Company intends to vigorously defend itself in both actions.

Other Contingencies

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes any ultimate liability arising from these actions will not have a material impact on its financial condition, results of operations or cash flows. It is possible a change could occur in the Company's estimates of the probability or amount of a liability being incurred. Such a change, should it occur, could be significant.

The Company routinely assesses, based on studies, expert analysis and legal reviews, its contingencies, obligations and commitments for remediation of contaminated sites, including assessments of ranges and probabilities of recoveries from other responsible parties who either have or have not agreed to a settlement as well as recoveries from insurance carriers. The Company's policy is to accrue and charge to current expense identified exposures related to environmental remediation sites based on estimates of investigation, cleanup and monitoring costs to be incurred.

The Company has potential liabilities under the Endangered Species Act and similar state statutes for species of fish, plants and wildlife that have either already been added to the endangered species list, listed as "threatened" or petitioned for listing. Thus far, measures adopted and implemented have had minimal impact on the Company. However, the Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to these issues.

Under the federal licenses for its hydroelectric projects, the Company is obligated to protect its property rights, including water rights. In addition, the Company holds additional non-hydro water rights. The States of Montana and Idaho are each conducting general adjudications of water rights in areas that include the Company's facilities in these states. Claims within the Clark Fork River basin and the Spokane River basin could adversely affect the energy production of the Company's hydroelectric facilities. The Company is and will continue to be a participant in the adjudication processes. The complexity of such adjudications makes each unlikely to be concluded in the foreseeable future. As such, it is not possible for the Company to estimate the impact of any outcome at this time. The Company will continue to seek recovery, through the ratemaking process, of all costs related to this issue.

NOTE 16. REGULATORY MATTERS

Power Cost Deferrals and Recovery Mechanisms

Deferred power supply costs are recorded as a deferred charge or liability on the Balance Sheets for future prudence review and recovery or rebate through retail rates. The power supply costs deferred include certain differences between actual net power supply costs incurred by Avista Corp. and the costs included in base retail rates. This difference in net power supply costs primarily results from changes in:

short-term wholesale market prices and sales and purchase volumes,

the level, availability and optimization of hydroelectric generation,

the level and availability of thermal generation (including changes in fuel prices),

retail loads, and

sales of surplus transmission capacity.

In Washington, the ERM allows Avista Corp. to periodically increase or decrease electric rates with WUTC approval to reflect changes in power supply costs. The ERM is an accounting method used to track certain differences between actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base retail rates for Washington customers. Under the ERM, the Company defers these differences (over the $4.0 million deadband and sharing bands) for future surcharge or rebate to customers.

The following is a summary of the ERM:

Annual Power Supply Cost Variability	Deferred for Future Surcharge or Rebate to Customers	Expense or Benefit to the Company
within +/- $0 to $4 million (deadband)	0%	100%
higher by $4 million to $10 million	50%	50%
lower by $4 million to $10 million	75%	25%
higher or lower by over $10 million	90%	10%

Total net deferred power costs under the ERM were assets of $37.6 million as of December 31, 2023 and $30.5 million as of December 31, 2022. The deferred power cost assets represent amounts due from customers, and deferred power cost liabilities represent amounts due to customers.

Pursuant to WUTC requirements, should the cumulative deferral balance exceed $30 million in the rebate or surcharge direction, the Company must make a filing with the WUTC to adjust customer rates to either return the balance to customers or recover the balance from customers. Avista Corp. makes an annual filing on, or before, April 1 of each year to provide the opportunity for the WUTC staff and other interested parties to review the prudence of, and audit, the ERM deferred power cost transactions for the prior calendar year. In June 2023, the Company received approval from the WUTC for a rate surcharge to customers over a two-year period, effective July 1, 2023.

In the 2024 Washington general rate case, the Company proposed changing the ERM so the entire mechanism would result in a 95 percent customer, 5 percent company sharing basis. This request is pending WUTC approval.

Avista Corp. has a PCA mechanism in Idaho allowing for the modification of electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, Avista Corp.

defers 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for its Idaho customers. The October 1 rate adjustments recover or rebate power costs deferred during the preceding July-June twelve-month period. Total net power supply costs deferred under the PCA mechanism were assets of $7.6 million as of December 31, 2023 and $16.3 million as of December 31, 2022. Deferred power cost assets represent amounts due from customers and liabilities represent amounts due to customers.

Natural Gas Cost Deferrals and Recovery Mechanisms

Avista Corp. files a PGA in all three states it serves to adjust natural gas rates for: 1) estimated commodity and pipeline transportation costs to serve natural gas customers for the coming year, and 2) the difference between actual and estimated commodity and transportation costs for the prior year. In Oregon, the Company absorbs (cost or benefit) 10 percent of the difference between actual and projected natural gas costs included in base retail rates for supply that is not hedged. Total net deferred natural gas costs were an asset of $51.4 million as of December 31, 2023 and $52.1 million as of December 31, 2022. Asset balances represent amounts due from customers and liabilities represent amounts due to customers.

Decoupling and Earnings Sharing Mechanisms

Decoupling (also known as an FCA in Idaho) is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. In each of Avista Corp.'s jurisdictions, Avista Corp.'s electric and natural gas revenues are adjusted so as to be based on the number of customers in certain customer rate classes and assumed "normal" kilowatt hour and therm sales, rather than being based on actual kilowatt hour and therm sales. The difference between revenues based on the number of customers and "normal" sales and revenues based on actual usage is deferred and either surcharged or rebated to customers beginning in the following year. Only residential and certain commercial customer classes are included in decoupling mechanisms.

Washington Decoupling and Earnings Sharing

In Washington, the WUTC approved the Company's decoupling mechanisms for electric and natural gas through March 31, 2025. In the Company's 2024 Washington general rate cases, it requested the mechanisms be extended through December 2026. That request is pending before the WUTC.

Electric and natural gas decoupling surcharge rate adjustments to customers are limited to a 3 percent increase on an annual basis, with remaining surcharge balance carried forward for recovery in a future period. There is no limit on the level of rebate rate adjustments. New customers added after a test period are not decoupled until included in a future test period.

The decoupling mechanisms each include an after-the-fact earnings test. At the end of each calendar year, separate electric and natural gas earnings calculations are made for the calendar year just ended. These earnings tests reflect actual decoupled revenues, normalized power supply costs and other normalizing adjustments. Through the 2022 general rate cases, the Company modified its earnings test so that if the Company earns more than 0.5 percent higher than the rate of return authorized by the WUTC in the multi-year rate plan, the Company would defer these excess revenues and later return them to customers.

Idaho FCA and Earnings Sharing Mechanisms

In Idaho, the IPUC approved the implementation of FCAs for electric and natural gas through March 31, 2025.

Oregon Decoupling Mechanism

In Oregon, the Company has a decoupling mechanism for natural gas. An earnings review is conducted on an annual basis. In the annual earnings review, if the Company earns more than 100 basis points above its allowed return on earnings, one-third of the earnings above the 100 basis points would be deferred and later returned to customers. The earnings review is separate from the decoupling mechanism and was in place prior to decoupling.

Cumulative Decoupling and Earnings Sharing Mechanism Balances

As of December 31, 2023 and December 31, 2022, the Company had the following cumulative balances outstanding related to decoupling and earnings sharing mechanisms in its various jurisdictions (dollars in thousands):

	December 31, 2023	December 31, 2022
Washington		
Decoupling rebate	$ (3,232)	$ (13,210)
Idaho		
Decoupling rebate	$ (7,961)	$ (7,889)
Provision for earnings sharing rebate	(572)	(686)
Oregon		
Decoupling (rebate) surcharge	$ (3,724)	$ 2,853

NOTE 17. NOTES RECEIVABLE FROM ASSOCIATED COMPANIES

Avista Capital may borrow up to $80 million from Avista Corp. to cover subsidiary cash needs in accordance with board-approved limits. Avista Capital pays interest on the outstanding amount at a rate at least equal to the Alternate Base Rate as defined in the Avista Corp. credit facility agreement, which is estimated at the Prime rate. This rate will be reset when the Agent bank on the Avista Corp. credit facility agreement changes the Prime rate or the margin.

As of December 31, 2023, the Company had a note receivable balance from Avista Capital of $20.6 with an applicable interest rate of 8.5 percent.

NOTE 18. SUBSEQUENT EVENTS

The Company has evaluated its subsequent events, noting the following events have occurred subsequent to December 31, 2023:

- On April 1, 2024, Avista Corporation (Avista Corp. or the Company) closed on the remarketing of $66.7 million and $17.0 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds due in 2032 and 2034, respectively. These bonds are secured by equal principal amounts of non-transferable first mortgage bonds of the Company. The term interest rate on both series of bonds is 3.875 percent. Avista Corp. purchased the bonds upon original issuance in December 2010, with the intention to hold the bonds until market conditions were favorable for remarketing the bonds to unaffiliated investors. While the Company was the holder of these bonds, the bonds were not reflected as an asset or a liability on the Consolidated Balance Sheets. With the remarketing of these bonds, the Company will recognize long term debt of $83.7 million. The net proceeds from the remarketing of these bonds were used to refinance existing short term debt obligations.

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

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

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	0	(11,038,551)					(11,038,551)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income							0		
3	Preceding Quarter/Year to Date Changes in Fair Value		8,980,326					8,980,326		
4	Total (lines 2 and 3)		8,980,326					8,980,326	155,176,032	164,156,358
5	Balance of Account 219 at End of Preceding Quarter/Year		(2,058,225)					(2,058,225)		
6	Balance of Account 219 at Beginning of Current Year		(2,058,225)					(2,058,225)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income							0		
8	Current Quarter/Year to Date Changes in Fair Value		1,701,116					1,701,116		
9	Total (lines 7 and 8)		1,701,116					1,701,116	171,180,214	172,881,330
10	Balance of Account 219 at End of Current Quarter/Year		(357,109)					(357,109)		

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

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

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)	7,781,458,219	5,352,763,952	1,683,865,098				744,829,169
4	Property Under Capital Leases	67,585,264						67,585,264
5	Plant Purchased or Sold							
6	Completed Construction not Classified							
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	7,849,043,483	5,352,763,952	1,683,865,098				812,414,433
9	Leased to Others							
10	Held for Future Use	3,658,920	2,928,319	180,896				549,705
11	Construction Work in Progress	170,812,964	132,548,007	7,682,114				30,582,843
12	Acquisition Adjustments	256,800	256,800					
13	Total Utility Plant (8 thru 12)	8,023,772,167	5,488,497,078	1,691,728,108				843,546,981
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	2,796,332,034	1,969,142,630	513,678,701				313,510,703
15	Net Utility Plant (13 less 14)	5,227,440,133	3,519,354,448	1,178,049,407				530,036,278
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	2,573,168,761	1,928,168,400	512,558,995				132,441,366
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							

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

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)
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	223,163,273	40,974,230	1,119,706				181,069,337
22	Total in Service (18 thru 21)	2,796,332,034	1,969,142,630	513,678,701				313,510,703
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)	2,796,332,034	1,969,142,630	513,678,701				313,510,703

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization						
3	(302) Franchise and Consents	46,795,649	42,494			(33,872)	46,804,271
4	(303) Miscellaneous Intangible Plant	52,229,864	9,157,151	3,579,985		33,872	57,840,902
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	99,025,513	9,199,645	3,579,985		0	104,645,173
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	3,857,583	0				3,857,583
9	(311) Structures and Improvements	140,868,863	534,075	11,568			141,391,370
10	(312) Boiler Plant Equipment	223,993,081	1,626,995	369,020			225,251,056
11	(313) Engines and Engine-Driven Generators	(5,008)	236,879				231,871
12	(314) Turbogenerator Units	57,991,911	324,774	17,328			58,299,357
13	(315) Accessory Electric Equipment	30,595,041	236,877				30,831,918
14	(316) Misc. Power Plant Equipment	17,129,513	236,878				17,366,391
15	(317) Asset Retirement Costs for Steam Production	15,536,251	1,927,245				17,463,496
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	489,967,235	5,123,723	397,916			494,693,042
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights						
19	(321) Structures and Improvements						
20	(322) Reactor Plant Equipment						

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)							
Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
21	(323) Turbogenerator Units						
22	(324) Accessory Electric Equipment						
23	(325) Misc. Power Plant Equipment						
24	(326) Asset Retirement Costs for Nuclear Production						
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)						
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights	65,888,976	2,520,485				68,409,461
28	(331) Structures and Improvements	111,713,114	5,885,120	797,307			116,800,927
29	(332) Reservoirs, Dams, and Waterways	256,473,521	9,805,966	410			266,279,077
30	(333) Water Wheels, Turbines, and Generators	235,789,409	848,353	605,126			236,032,636
31	(334) Accessory Electric Equipment	84,873,187	1,261,390	261,085			85,873,492
32	(335) Misc. Power Plant Equipment	13,734,934	646,716	8,715			14,372,935
33	(336) Roads, Railroads, and Bridges	3,648,611	249,648	10,101			3,888,158
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	772,121,752	21,217,678	1,682,744			791,656,686
36	D. Other Production Plant						
37	(340) Land and Land Rights	905,167	0				905,167
38	(341) Structures and Improvements	17,613,988	23,181	37,331			17,599,838
39	(342) Fuel Holders, Products, and Accessories	21,070,907	116				21,071,023
40	(343) Prime Movers	21,443,903		14,110			21,429,793

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)							
Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
41	(344) Generators	237,686,875	718,872	423,966			237,981,781
42	(345) Accessory Electric Equipment	25,712,405	920,937	73,075			26,560,267
43	(346) Misc. Power Plant Equipment	1,642,746	58	16,146			1,626,658
44	(347) Asset Retirement Costs for Other Production	351,683	0				351,683
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	326,427,674	1,663,164	564,628			327,526,210
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,588,516,661	28,004,565	2,645,288			1,613,875,938
47	3. Transmission Plant						
48	(350) Land and Land Rights	30,092,047	168,213	2,024			30,258,236
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	30,634,477	6,880,190	133,952			37,380,715
50	(353) Station Equipment	365,127,492	25,527,973	2,398,123			388,257,342
51	(354) Towers and Fixtures	17,217,152	(53,118)	24,566			17,139,468
52	(355) Poles and Fixtures	353,099,994	28,936,574	700,974			381,335,594
53	(356) Overhead Conductors and Devices	182,973,690	8,224,033	363,594			190,834,129
54	(357) Underground Conduit	3,577,440	(363,503)				3,213,937
55	(358) Underground Conductors and Devices	7,054,975	(363,502)				6,691,473
56	(359) Roads and Trails	2,608,136	0				2,608,136
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	992,385,403	68,956,860	3,623,233			1,057,719,030
59	4. Distribution Plant						
60	(360) Land and Land Rights	16,392,078	2,097,982	0		(2,068,423)	16,421,637

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)							
Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
61	(361) Structures and Improvements	28,488,284	2,547,182	50,943			30,984,523
62	(362) Station Equipment	164,195,204	10,461,576	1,484,822			173,171,958
63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	538,890,192	48,170,081	1,315,943			585,744,330
65	(365) Overhead Conductors and Devices	342,545,005	23,934,559	101,045			366,378,519
66	(366) Underground Conduit	156,935,860	18,822,448	32,037			175,726,271
67	(367) Underground Conductors and Devices	274,250,687	18,050,349	192,176			292,108,860
68	(368) Line Transformers	327,782,685	30,649,538	83,759			358,348,464
69	(369) Services	214,871,264	11,146,575	38,168			225,979,671
70	(370) Meters	86,339,367	1,322,659	105,626			87,556,400
71	(371) Installations on Customer Premises	6,679,677	4,085,651	132,384			10,632,944
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	78,377,324	6,208,672	332,915			84,253,081
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,235,747,627	177,497,272	3,869,818		(2,068,423)	2,407,306,658
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						

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)							
Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
82	(385) Miscellaneous Regional Transmission and Market Operation Plant						
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)						
85	6. General Plant						
86	(389) Land and Land Rights	885,665				197,341	1,083,006
87	(390) Structures and Improvements	20,705,705	561,785	221,982			21,045,508
88	(391) Office Furniture and Equipment	3,316,124	834,587	174,089			3,976,622
89	(392) Transportation Equipment	59,454,054	4,943,929	2,118,366		78,214	62,357,831
90	(393) Stores Equipment	472,784	0				472,784
91	(394) Tools, Shop and Garage Equipment	8,187,992	1,000,962	183,415			9,005,539
92	(395) Laboratory Equipment	3,228,953	90,866	14,532			3,305,287
93	(396) Power Operated Equipment	28,073,572	142,813	2,783,853			25,432,532
94	(397) Communication Equipment	44,938,649	1,462,865	4,122,243			42,279,271
95	(398) Miscellaneous Equipment	280,797	41,703	63,727			258,773
96	SUBTOTAL (Enter Total of lines 86 thru 95)	169,544,295	9,079,510	9,682,207		275,555	169,217,153
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant						
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	169,544,295	9,079,510	9,682,207		275,555	169,217,153
100	TOTAL (Accounts 101 and 106)	5,085,219,499	292,737,852	23,400,531		(1,792,868)	5,352,763,952
101	(102) Electric Plant Purchased (See Instr. 8)						

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)							
Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
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)	5,085,219,499	292,737,852	23,400,531		(1,792,868)	5,352,763,952

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

ELECTRIC PLANT HELD FOR FUTURE USE (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	Distribution Plant Land, Carlin Bay, Idaho	12/01/2010	12/31/2027	162,352
3	Transmission Plant Land, Spokane, Washington	12/01/2011	12/31/2027	411,202
4	Transmission Plant Land, Spokane, Washington	07/01/2014	12/31/2027	62,168
5	Transmission Plant Land, Spokane, Washington	01/01/2017	12/31/2027	56,311
6	Transmission Plant Land, Spokane, Washington	03/01/2019	12/31/2027	323,427
7	Transmission Plant Land, Spokane, Washington	03/01/2019	12/31/2027	546,503
8	Distribution Plant Land, Colville, Washington	06/01/2019	12/31/2027	104,527
9	Transmission Plant Land, Sandpoint, Idaho	07/01/2019	12/31/2027	486,299
10	Distribution Plant Land, Coeur d'Alene, Idaho	11/01/2020	12/31/2027	775,530
21	Other Property:			
22				
23				
24				
25				
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38				

ELECTRIC PLANT HELD FOR FUTURE USE (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)
39				
40				
41				
42				
43				
44				
45				
46				
47	TOTAL			2,928,319

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Substation Rebuilds	20,828,957
2	Metro 115kV Substation	16,733,242
3	Long Lake Plant Upgrades	13,777,343
4	CG HED Station Service Replacement	12,775,533
5	LL HED Stability Enhancement	8,913,444
6	Coyote Springs 2 CT Rotor Replacement	4,640,784
7	HMI Control Software	3,846,698
8	OMS/ADMS	3,096,493
9	Substation - Capital Spares	2,969,262
10	Low Priority Ratings Mitigation	2,503,720
11	Westside 230 kV Substation - Rebuild	2,498,743
12	Downtown Network - Performance & Capacity	2,397,630
13	Nine Mile Unit 3 Mechanical Overhaul	2,366,619
14	New Substations	2,286,983
15	Garden Springs 230-115 kV Substation	2,040,792
16	PF North Channel Spillway Repl	1,846,082
17	Wildfire Resiliency	1,679,393
18	Distribution - Big Bend, North & West	1,595,001
19	Substation Asset Mgmt Capital Maintenance	1,343,678
20	Distribution Line Transformers	1,260,495
21	Tribal Permits and Settlements	1,256,106
22	Regulating Hydro	1,160,118
23	Generation, Substation & Gas Location Security	1,154,991
24	Transportation Equip	1,152,249
25	CG Stop Log Replacement	1,062,498
26	Minor Projects under $1,000,000	14,024,896
27	R&D/Strategic Initiatives	3,336,257
43	Total	132,548,007

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

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

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	1,814,695,451	1,814,695,451		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	149,272,689	149,272,689		
4	(403.1) Depreciation Expense for Asset Retirement Costs	0			
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	4,926,093	4,926,093		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1					
9.2					
9.3					
9.4					
9.5					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	154,198,782	154,198,782	0	0
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(19,822,225)	(19,822,225)		
13	Cost of Removal	(1,305,366)	(1,305,366)		
14	Salvage (Credit)	6,963	6,963		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(21,120,628)	(21,120,628)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Depreciation offset for non-recoverable plant for Boulder Park	(112,280)	(112,280)		
17.2	Change in APx Accrual	(30,001)	(30,001)		
17.3	ARO Depreciation	2,813,972	2,813,972		
17.4	Transfers	110,738	110,738		
17.5	Change in RWIP	(4,169,754)	(4,169,754)		
17.6	General Plant Common Allocated	(18,217,880)	(18,217,880)		

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)					
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)
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,928,168,400	1,928,168,400	0	0
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	394,650,809	394,650,809		
21	Nuclear Production				
22	Hydraulic Production-Conventional	202,979,974	202,979,974		
23	Hydraulic Production-Pumped Storage				
24	Other Production	177,969,738	177,969,738		
25	Transmission	285,851,148	285,851,148		
26	Distribution	788,670,773	788,670,773		
27	Regional Transmission and Market Operation				
28	General	78,045,958	78,045,958		
29	TOTAL (Enter Total of lines 20 thru 28)	1,928,168,400	1,928,168,400	0	0

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (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	Investment in Avista Capital	01/01/1997		256,138,971	0		256,138,971	
2	Avista Capital - Equity in Earnings			(106,266,632)	(4,288,022)		(110,554,654)	
3	Investment in AERC	07/01/2014		89,816,380	0		89,816,380	
4	AERC - Equity in Earnings			21,072,251	8,737,693		29,809,944	
42	Total Cost of Account 123.1 $		Total	260,760,970	4,449,671		265,210,641	

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

MATERIALS AND SUPPLIES

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)	4,252,607	4,683,150	
2	Fuel Stock Expenses Undistributed (Account 152)	0	0	
3	Residuals and Extracted Products (Account 153)	0	0	
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	51,057,881	58,422,040	(1) Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	5,069,997	5,531,231	(1) Electric
8	Transmission Plant (Estimated)	179,891	114,052	(1) Electric
9	Distribution Plant (Estimated)	806,251	897,097	(1) Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	16,339,904	14,528,108	(1) Electric, (2) Natural Gas
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	73,453,924	79,492,528	
13	Merchandise (Account 155)	0	0	
14	Other Materials and Supplies (Account 156)	0	0	
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)	0	0	
16	Stores Expense Undistributed (Account 163)	0	0	
17				
18				
19				
20	TOTAL Materials and Supplies	77,706,531	84,175,678	

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

Transmission Service and Generation Interconnection Study Costs

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	ENEL Studies for TSR	40,942	186200	0	
20	Total	40,942		0	
21	**Generation Studies**				
22	Aurora Solar Project #59	100,571	186200	76,515	186210
23	Post Falls HED Project #63	101,121	186200	0	
24	Clearwater Wind II Proj #68	12,172	186200	0	
25	Clearwater Wind III Proj #69	16,505	186200	0	
26	Haymaker Wind Proj #82	8,748	186200	0	
27	Martinsdale Wind Proj #83	4,324	186200	0	
28	Jane Wind 2 Proj #96	1,968	186200	0	
29	Jane Wind Proj #95	2,127	186200	0	
30	Big Sky Connector Line Project	2,752	186200	0	
31	Broadview IV Project #107	2,949	186200	0	
32	Ursus Wind Project #108	3,240	186200	0	
33	Gordon Butte South Wind Q116	3,171	186200	0	
34	CS PV Q113	1,820	186200	0	
35	CS Wind 2 Q115	1,618	186200	0	
36	CS Wind 1 Q114	1,149	186200	0	
37	Triple Oak Connector Line	2,545	186200	0	
38	North Plains Connector Line	2,154	186200	0	
39	Ursiane Wind #118	2,281	186200	0	
40	Royal Slope - Juwi - ESA	9,262	186200	0	
41	Colstrip Solar	1,537	186200	0	
42	CA1 West Plains	45,472	186200	17,037	186210
43	CA1 Phase 1 ReStudy	17,584	186200	0	
44	CA1 Phase 2 Study	2,618	186200	0	
45	CA5 Palouse	45,634	186200	0	
46	CA5 Phase 2 Study	47,956	186200	0	
47	CA7 Big Bend	41,599	186200	5,673	186210

Transmission Service and Generation Interconnection Study Costs					
Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
48	CA7 Phase 2 Study	40,404	186200	0	
49	Kettle Falls Upgrade Proj #66	61,211	186200	61,211	186210
50	Big Bend Cluster Phase 2 T7a	47,451	186200	47,451	186210
51	CA6 Lewis Clark	37,622	186200	37,622	186210
52	CA3 Idaho	27,819	186200	27,819	186210
39	Total	697,384		273,328	
40	Grand Total	(a)738,326		(b)273,328	

FOOTNOTE DATA

(a) Concept: StudyCostsIncurred
Total life to date costs
(b) Concept: StudyCostsReimbursements
Total life to date reimbursements

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

OTHER REGULATORY ASSETS (Account 182.3)

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	(a) WA Excess Nat Gas Line Extension Allowance	4,328,385	0	407	1,745,141	2,583,244
2	(b) Reg Asset Post Ret Liabililty	128,847,130	1,796,907	228	18,181,644	112,462,393
3	(c) Regulatory Asset FAS 109 Utility Plant	80,549,288	1,556,488	283	3,933,322	78,172,454
4	(d) Regulatory Asset FAS 109 DSIT Non Plant	4,442,326	593,287	283	2,353,940	2,681,673
5	(e) Regulatory Asset Lake CDA Settlement-Varies	37,809,157	0	407	1,116,805	36,692,352
6	(f) Reg Assets-Decoupling Surcharges	9,089,302	36,741,461	456, 495	43,395,041	2,435,722
7	(g) Reg Asset - Colstrip	14,976,471	6,165,968	407	1,713,471	19,428,968
8	(h) Regulatory Asset FAS 143 Asset Retirement Obligation	2,165,181	133,388		0	2,298,569
9	(i) Regulatory Asset Workers Comp	989,028	956,123	242	14,986	1,930,165
10	(j) Interest Rate Swap Asset	185,919,054	1,417,272	Various	7,847,927	179,488,399
11	(k) DSM Asset	3,683,352	8,398,035	Various	1,823,901	10,257,486
12	(l) Deferred ITC	3,769,051	0	283, 410	166,945	3,602,106
13	(m) Regulatory Asset MDM System	32,380,865	0	407, 419	3,035,706	29,345,159
14	(n) Regulatory Asset BPA Residential Exchange	1,298,948	1,861,113	407	1,609,846	1,550,215
15	(o) Regulatory Asset FISERV	406,443	117,683	407, 419	353,815	170,311
16	(p) Regulatory Asset AFUDC (PIS,WIP) & Equity DFIT	59,662,251	30,423,065	Various	31,019,224	59,066,092
17	Regulatory Asset ID PCA Deferral	16,341,994	15,169,526	557, 419	23,884,029	7,627,491
18	(q) Existing Meters/ERTS Retirement Def	19,459,498	0	108, 407	1,824,328	17,635,170

OTHER REGULATORY ASSETS (Account 182.3)

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
19	(r) Regulatory Asset Colstrip Community Fund	1,500,000	562,500	182, 407	1,312,500	750,000
20	(s) Regulatory Asset COVID-19	1,241,772	1,977,642	186, 407	2,561,625	657,789
21	(t) Regulatory Asset Energy Imbalance Market	699,119		182, 407	116,520	582,599
22	(u) Regulatory Asset Oregon CAT Tax	628,249	12,664	407, 419	630,849	10,064
23	(v) Regulatory Asset- Wildfire Resiliency & Balancing	18,186,521	11,788,958	182	6,238,024	23,737,455
24	(w) Deferral for CS2 & Colstrip (O&M, Excess Depr)	1,874,781	2,238,354	182, 407	2,094,878	2,018,257
25	(x) Regulatory Asset Tax Basis Flow through	138,273,552	9,853,657	282, 283	2,958,003	145,169,206
26	(y) Reg Asset - Intervenor Fund Deferral	0	307,699	182	201,760	105,939
27	(z) Unrealized Currency Exchange	1,492,610	0	143	1,492,610	0
28	(aa) Regulatory Asset Commodity MTM ST & LT	130,274,212	272,303,368	244, 175	333,438,131	69,139,449
29	(ab) Regulatory Asset Energy Affordability Act	219,732	1,817,222	182, 908	735,954	1,301,000
30	(ac) Reg Asset - Insurance Balancing Acct	0	411,192	182, 407	122,403	288,789
31	(ad) Reg Asset - CPP	0	594,833		0	594,833
32	(ae) Deferred Regulatory Fees	98,368	2,471,646	407, 419	654,598	1,915,416
33	(af) Regulatory Asset Pension Settlement Deferral	11,827,588	0	182, 407	985,632	10,841,956
34	(ag) Reg Asset - CCA	0	46,022,329	407	0	46,022,329
35	(ah) WA ERM Deferral - Approved for Rebate	0	38,639,584	182, 557	13,161,287	25,478,297

OTHER REGULATORY ASSETS (Account 182.3)

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
36	(al) REG ASSET - MT RIVERBED ESCROW INT	0	1,613,960		0	1,613,960
37	(al) Reg Asset - Depreciation	0	511,800		0	511,800
38	(ak) REG ASSET - CPP RNG	0	25,000		0	25,000
44	TOTAL	912,434,228	496,482,724		510,724,845	898,192,107

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Residential Schedule 101 customers who receive a natural gas line extension as part of conversion to natural gas from another fuel source. Amort for a period of 3 years on the excess allowance exceeding the cost of the line extension.
(b) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Recognition of the overfunded and underfunded status of a defined benefit post retirement plan based on ASC 715 for financial reporting.
(c) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Deferred tax flow through balance on utility plant. Amortization occurs over book life of respective utility plant assets.
(d) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Deferred tax flow through balance on utility plant. Amortization occurs over book life of respective utility plant assets.
(e) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
WA Docket No UE-080416; ID order AVU-E-08-01. Amort thru 2059.
(f) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Decoupling revenue deferrals are recognized during the period they occur, subject to certain limitations. Revenue is expected to be collected within 24 months of the deferral.
(g) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
For WA Elec, amort period is 33.75yrs as per Order 09, dockets UE-190334, UG-190335, UE-190222 (Consolidated). For ID Elec, amort is for 34.75yrs as per Order 34276, AVU-E-18-03, Amor ends in 2054 for both jurisdictions.
(h) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Reg assets related to deferred ARO expenses for Kettle Falls and Coyote Springs thermal plants. The expenses will not be collected from customers until actual work is performed.
(i) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Quarterly adjustments to workers comp reserve for current unpaid claims.
(j) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Settled swaps are amortized over the life of the associated debt.
(k) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Amort period varies depending on timing of transactions.
(l) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Amort period varies depending on underlying transactions.
(m) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
WA Docket Nos UE-180418, UG-180419.
(n) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Avista is a participant in the Residential Exchange Program with Bonneville Power Administration. Customers served under Schedules 1, 12, 22, 32, and 48 are given a rate adjustment based on Schedule 59 for WA and Id. Amort is based on customer usage.
(o) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
ID Order No 33494, Docket Nos. AVU-E-16-01 and Stipulation and Settlement Docket No AVU-E-19-04.
(p) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Deferring the difference between FERC formula and State approved AFUDC rates from 2010 to present.
(q) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
WA Docket No UE-002066 and ID Order No 28648.
(r) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
WA Order 09 in Dockets UE-190334, UE-190222. Deferral of customer portion for future rate recovery. The funds are set aside to help the Colstrip community transition away from economic activity related to coal-fired generation.
(s) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Deferral of COVID-19 costs as per ID PUC Order No 34718, OR PUC Order No 20-401, Docket UM 2069 and WA UTC Order No. 01, Dockets UE-200407 and UG-200408.
(t) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
ID PUC Order No 34606. Deferral of costs related to Avista's entry in the Energy Imbalance Market in March 2022.
(u) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
OR PUC Order No. 20-398, Docket UM-2042.
(v) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Deferral of O&M wildfire expenses as per ID PUC Order 34883 and WA Dockets UE-200900, UG-200901, and UE-200894.
(w) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
WA Order 09, Docket Nos. UE-190334, UG-190335, and UE-190222.
(x) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
WA Order 01, Dockets UE-200895 and UG-200896, ID Case Nos. AVU-E-20-12 and AVU-G-20-07 Order No. 34906, and OR Docket No UM 2124 Order No 21-131 - Accounting method change for federal income tax expense associated with Industry Director Directive No. 5 mixed service costs for meters.
(y) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
WA Docket No UG-220596 and UE-220151.
(z) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Recognition of other liability related to foreign exchange hedge rates over a two year period.
(aa) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
WA Docket No UE-002066 and ID Order No 28648.
(ab) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Deferral of costs associated with OR House Bill 2475.
(ac) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
To defer costs above or below the baseline in accordance with Order No 10/04 Docket Nos UE-220053, UE-210854, and UG-220054.
(ad) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
To defer costs of compliance with the Climate Protection Plan pursuant to ORS 757.259 and OAR 860-027-0300(4). Docket No. UM2254.
(ae) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
OR Docket No UG415/Advice No. 21-06-G. Amortization of amounts deferred previously in Order No. 20-254 in UG 395. WA Docket No UE-220892 and UG-220893 Order 01.
(af) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
To defer expected impacts associated with the occurrence of pension events and amortization over 12 years - ID Case Nos. AVU-E-22-16 and AVU-G-22-08, WA Docket Nos UE-220898 and UG-220899, and OR UM 2267.
(ag) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
To defer costs of compliance with the Climate Commitment Act in accordance with WAC 480-100-203(3) and WAC 480-90-203(3). WA Docket No UG-220803.
(ah) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
WA ERM Amortizing Deferral - Approved for Rebate Balance. Began amortizing 7/1/23.
(ai) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Deferral for the Montana Riverbed land lease agreement escrow release provisions following Avista and State of Montana Agreement on an updated balance owed.
(aj) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Difference between depreciation rates in GRC verses effective date based on ID Order 35909 Dockets AVU-E-23-01 and AVU-G-23-01.
(ak) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
OR Order 23-145

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Credits Account Charged (d)	CREDITS Credits Amount (e)	Balance at End of Year (f)
1	Reg Asset -Battery Storage	3,422,093				3,422,093
2	Plant Alloc of Clearing Journal	2,344,921	3,863,077			6,207,998
3	Reg Asset - ERM	35,799,197		VAR	23,638,534	12,160,663
4	WA REC Deferral	0	412,639			412,639
5	Reg Asset - Decoupling Deferred	4,458,589	4,653,520			9,112,109
6	Reg Asset - COVID 19 Deferral	8,551,568	2,932,987			11,484,555
7	Reg Asset - CEIP	67,334	965,873			1,033,207
8	Reg Asset - Williams Outage	0	10,297,716			10,297,716
9	Misc Deferred Debits - Pension	13,381,750	19,622,239			33,003,989
10	Nez Perce Settlement	108,749		557	5,188	103,561
11	City of Post Falls Lease Pay	0	126,851			126,851
12	Post Falls HED Project 63	99,929	1,192			101,121
13	Misc. Deferred Debits <$100,000	686,038		VAR	634,636	51,402
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	68,920,168				87,517,904

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Electric	105,974,248	84,418,866
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	105,974,248	84,418,866
9	Gas		
10	Gas	27,957,319	24,041,518
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	27,957,319	24,041,518
17.1	(a) Other	135,539,045	105,691,804
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	269,470,612	214,152,188

Notes

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfAccumulatedDeferredIncomeTax

	Beg. Balance	End. Balance
Pension, Medical, and SERP	39,011,736	34,671,763
Federal Income Tax Carryforwards	32,930,810	27,406,304
State Income Tax Carryforwards	22,175,174	17,952,286
Derivative Instruments	29,450,122	16,269,451
Compensation and Payroll	6,455,693	6,986,432
Plant Excess Deferred Gross Up	5,388,884	3,951,713
Other Common Deferred Tax Assets	126,626	(1,546,146)
Total	135,539,045	105,691,803

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

CAPITAL STOCKS (Account 201 and 204)

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)
1	Common Stock (Account 201)					
2	No Par Value	200,000,000			78,074,587	1,596,986,047
3	Restricted Shares					
11	Total	200,000,000			78,074,587	1,596,986,047
12	Preferred Stock (Account 204)					
13	Cumulative	10,000,000				
16	Total	10,000,000				0
1	Capital Stock (Accounts 201 and 204) - Data Conversion					
2						
3						
4						
5	Total					

CAPITAL STOCKS (Account 201 and 204)

Line No.	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				
2				
3			152,140	6,463,455
11				
12				
13				
16				
1				
2				
3				
4				
5				

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2024-04-12	Year/Period of Report End of: 2023/ Q4

Other Paid-in Capital

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	(10,696,711)
15.1	Reclassification of subsidiary APIC	7,964,306
15	Increases (Decreases) Due to Miscellaneous Paid-In Capital	7,964,306
16	Ending Balance Amount	(2,732,405)
17	Historical Data - Other Paid in Capital	
18	Beginning Balance Amount	
19	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	(2,732,405)

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

CAPITAL STOCK EXPENSE (Account 214)

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock - no par	(50,073,294)
22	TOTAL	(50,073,294)

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

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

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)
1	Bonds (Account 221)						
2	FMBS - SERIES C - 6.37% DUE 06/18/2028	221300	25,000,000		158,304		
3	COLSTRIP 2010A PCRBs DUE 2032	221350	66,700,000				
4	COLSTRIP 2010B PCRBs DUE 2034	221360	17,000,000				
5	FMBS - 6.25% DUE 12-01-35	221400	150,000,000		1,812,935		900,500
6	FMBS - 5.70% DUE 07-01-2037	221420	150,000,000		4,702,304		222,000
7	5.55% SERIES DUE 12-20-2040	221540	35,000,000		258,834		
8	4.45% SERIES DUE 12-14-2041	221560	85,000,000		692,833		
9	4.11% SERIES DUE 12-1-2044	221610	60,000,000		428,205		
10	4.37% SERIES DUE 12-1-2045	221620	100,000,000		590,761		
11	4.23% SERIES DUE 11-29-2047	221580	80,000,000		730,832		
12	3.91% SERIES DUE 12-1-2047	221640	90,000,000		552,539		
13	4.35% SERIES DUE 6-1-2048	221650	375,000,000		4,246,448		378,750
14	3.43% SERIES DUE 12-1-2049	221660	180,000,000		1,108,340		
15	3.07% SERIES DUE 9-1-2050	221670	165,000,000		1,074,990		
16	2.90% SERIES DUE 10/01/2051	221680	140,000,000		1,083,452		
17	3.54% SERIES DUE 2051	221630	175,000,000		1,042,569		
18	4.00% SERIES DUE 4/1/2052	221690	400,000,000		4,579,993		
19	5.66% SERIES DUE 04-01-2053	221710	250,000,000		1,444,302		
20	Subtotal		2,543,700,000		24,507,641	0	1,501,250

LONG-TERM DEBT (Account 221, 222, 223 and 224)							
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)
21	Reacquired Bonds (Account 222)						
22	COLSTRIP 2010A PCRBs DUE 2032	221350	66,700,000				
23	COLSTRIP 2010B PCRBs DUE 2034	221360	17,000,000				
24	Subtotal		83,700,000				
25	Advances from Associated Companies (Account 223)						
26	ADVANCE ASSOCIATED AVISTA CAPITAL II (ToPRS)	223011	51,547,000		1,296,086		
27	Subtotal		51,547,000		1,296,086		
28	Other Long Term Debt (Account 224)						
29							
30							
31							
32	Subtotal						
33	TOTAL		2,678,947,000				

LONG-TERM DEBT (Account 221, 222, 223 and 224)						
Line No.	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						
2	06/19/1998	06/19/2028	06/19/1998	06/19/2028	25,000,000	1,592,500
3	12/15/2010	10/01/2032	12/15/2010	10/01/2032	66,700,000	
4	12/15/2010	03/01/2034	12/15/2010	03/01/2034	17,000,000	
5	11/17/2005	12/01/2035	11/17/2005	12/01/2035	150,000,000	9,375,000
6	12/15/2006	07/01/2037	12/15/2006	07/01/2037	150,000,000	8,550,000
7	12/20/2010	12/20/2040	12/20/2010	12/20/2040	35,000,000	1,942,500
8	12/14/2011	12/14/2041	12/14/2011	12/14/2041	85,000,000	3,782,500
9	12/18/2014	12/01/2044	12/18/2014	12/01/2044	60,000,000	2,466,000
10	12/16/2015	12/01/2045	12/16/2015	12/01/2045	100,000,000	4,370,000
11	11/30/2012	11/29/2047	11/30/2012	11/29/2047	80,000,000	3,384,000
12	12/14/2017	12/01/2047	12/14/2017	12/01/2047	90,000,000	3,519,000
13	05/22/2018	06/01/2048	05/22/2018	06/01/2048	375,000,000	16,312,500
14	11/26/2019	12/01/2049	11/26/2019	12/01/2049	180,000,000	6,174,000
15	09/30/2020	09/30/2050	09/30/2020	09/30/2050	165,000,000	5,065,500
16	09/28/2021	10/01/2051	09/28/2021	10/01/2051	140,000,000	4,060,000
17	12/15/2016	12/01/2051	12/15/2016	12/01/2051	175,000,000	6,195,000
18	03/17/2022	04/01/2052	03/17/2022	04/01/2052	400,000,000	16,000,000
19	03/29/2023	04/01/2053	03/29/2023	04/01/2053	250,000,000	10,726,613
20					2,543,700,000	103,515,113
21						
22	12/15/2010	10/01/2032	12/15/2010	10/01/2032	66,700,000	2,272,812
23	12/15/2010	03/01/2034	12/15/2010	03/01/2034	17,000,000	579,277
24					83,700,000	2,852,089
25						
26	06/03/1997	06/01/2037	06/03/1997	06/01/2037	51,547,000	2,503,671
27					51,547,000	2,503,671
28						
29						
30						
31						

LONG-TERM DEBT (Account 221, 222, 223 and 224)						
Line No.	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)
32					0	
33					2,511,547,000	108,870,873

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	171,180,214
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Contributions in Aid of Construction	10,754,152
6	Other	36,360,532
9	Deductions Recorded on Books Not Deducted for Return	
10	Book Depreciation	269,272,553
11	Federal Income Tax Expense	(36,924,664)
12	State Income Tax Expense	(31,119)
13	Subsidiary Overheads	360,971
14	Other	16,809,291
14	Income Recorded on Books Not Included in Return	
15	Subsidiary Earnings	4,449,671
16	Other	3,328,370
19	Deductions on Return Not Charged Against Book Income	
20	Tax Depreciation	234,949,702
21	Plant Basis Adjustments	137,699,340
22	Other	87,001,270
27	Federal Tax Net Income	353,577
28	Show Computation of Tax:	
29	Federal Tax at 21%	74,251
30	Business Credits Utilized	(989,812)
31	Prior Year True Ups	1,271,341
32	WA Remand at 35%	(16,263)
33	Total Federal Current Tax Expense	339,517

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (e)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (f)
1	Income Tax	Federal Tax		2021		
2	Income Tax	Federal Tax		2022		
3	Income Tax	Federal Tax		2023		
4	**Subtotal Federal Tax**				0	0
5	Property Tax	Property Tax	WA	2022	18,573,985	
6	Property Tax	Property Tax	WA	2023		
7	Property Tax	Property Tax	ID	2022	2,857,137	
8	Property Tax	Property Tax	ID	2023		
9	Property Tax	Property Tax	MT	2022	4,840,427	
10	Property Tax	Property Tax	MT	2023		
11	Property Tax	Property Tax	OR	2022		4,517,894
12	Property Tax	Property Tax	OR	2023		
13	**Subtotal Property Tax**				26,271,549	4,517,894
14	Excise Tax	Excise Tax	WA	2022	3,980,660	
15	Excise Tax	Excise Tax	WA	2023		
16	Corp Activities Tax-CAT	Excise Tax	OR	2022		
17	Corp Activities Tax-CAT	Excise Tax	OR	2023		
18	**Subtotal Excise Tax**				3,980,660	0
19	Natural Gas Use Tax	Sales And Use Tax	WA	2022	46,608	
20	Use Tax	Sales And Use Tax	WA	2023		
21	Use Tax	Sales And Use Tax	WA	2022	210,812	
22	Use Tax	Sales And Use Tax	WA	2023		
23	Use Tax	Sales And Use Tax	ID	2022	31,762	
24	Use Tax	Sales And Use Tax	ID	2023		
25	**Subtotal Sales And Use Tax**				289,182	0
26	Municipal Occupation Tax	Local Tax	WA	2022	4,001,655	

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (e)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (f)
27	Municipal Occupation Tax	Local Tax	WA	2023		
28	**Subtotal Local Tax**				4,001,655	0
29	KWH Tax	Other Taxes	ID	2022	24,554	
30	KWH Tax	Other Taxes	ID	2023		
31	KWH Tax	Other Taxes	MT	2022	239,401	
32	KWH Tax	Other Taxes	MT	2023		
33	WA Renewable Energy Credits	Other Taxes		2023		
34	**Subtotal Other Taxes**				263,955	0
35	Income Tax	State Tax	ID	2022		
36	Income Tax	State Tax	ID	2023		
37	Income Tax	State Tax	MT	2022		
38	Income Tax	State Tax	MT	2023		
39	Income Tax	State Tax	OR	2022		
40	Income Tax	State Tax	OR	2023		
41	Income Tax	State Tax	Misc	2022		
42	**Subtotal State Tax**				0	0
43	Payroll Taxes	Payroll Tax	ID	2022	6,943	
44	Payroll Taxes	Payroll Tax	ID	2023		
45	Payroll Taxes	Payroll Tax	MT	2022	528	
46	Payroll Taxes	Payroll Tax	MT	2023		
47	Payroll Taxes	Payroll Tax	OR	2022	14,255	
48	Payroll Taxes	Payroll Tax	OR	2023		
49	Payroll Taxes	Payroll Tax	WA	2022	72,315	
50	Payroll Taxes	Payroll Tax	WA	2023		
51	Payroll Taxes	Payroll Tax	Misc	2022		
52	Payroll Taxes	Payroll Tax	Misc	2023		
53	Payroll Taxes	Payroll Tax	FED	2021		
54	Payroll Taxes	Payroll Tax	FED	2022	796,213	
55	Payroll Taxes	Payroll Tax	FED	2023		

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (e)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (f)
56	**Subtotal Payroll Tax**				890,254	0
57	Franchise Tax	Franchise Tax	ID	2022	1,285,869	
58	Franchise Tax	Franchise Tax	ID	2023		
59	Franchise Tax	Franchise Tax	OR	2022	1,537,313	
60	Franchise Tax	Franchise Tax	OR	2023		
61	**Subtotal Franchise Tax**				2,823,182	0
62	Consumer Council Fee	Other License And Fees Tax	MT	2022	8	
63	Consumer Council Fee	Other License And Fees Tax	MT	2023		
64	Public Commission Fee	Other License And Fees Tax	MT	2022	42	
65	Public Commission Fee	Other License And Fees Tax	MT	2023		
66	**Subtotal Other License And Fees Tax**				50	0
40	TOTAL				38,520,487	4,517,894

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR						
Line No.	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR Taxes Accrued (Account 236) (j)	BALANCE AT END OF YEAR Prepaid Taxes (Included in Account 165) (k)	DISTRIBUTION OF TAXES CHARGED Electric (Account 408.1, 409.1) (l)
1		(800,000)	(800,000)	0		
2	1,271,339	238,248	(1,033,091)	0		730,140
3	(1,007,626)	(1,679,000)	(671,374)	0		(8,445,193)
4	263,713	(2,240,752)	(2,504,465)	0	0	(7,715,053)
5	(2,685,052)	15,889,288	355	0		(2,115,275)
6	14,235,079	1,405	(354)	14,233,320		10,920,067
7	(1,236)	2,857,841	1,940	0		
8	4,149,832	2,099,678	(1,940)	2,048,214		3,177,624
9	243	4,840,669	(1)	0		243
10	7,382,564	3,707,034		3,675,530		7,382,564
11	4,517,893		1	0		1,866,618
12	4,233,758	8,467,363	(1)	0	4,233,606	1,690,101
13	31,833,081	37,863,278	0	19,957,064	4,233,606	22,921,942
14	78,882	4,059,542		0		81,744
15	34,977,642	31,016,843		3,960,799		24,313,394
16	(5,020)		5,020	0		
17	799,999	700,000	(99,999)	0		
18	35,851,503	35,776,385	(94,979)	3,960,799	0	24,395,138
19	709	47,318	1	0		709
20	100,177	94,352	(1)	5,824		3,022
21	(7,910)	202,902		0		
22	1,830,363	1,588,474		241,889		
23		31,761	(1)	0		
24	166,826	114,132	1	52,695		
25	2,090,165	2,078,939	0	300,408	0	3,731
26	48,832	4,050,487		0		44,370
27	29,728,805	25,905,105		3,823,700		20,889,865
28	29,777,637	29,955,592	0	3,823,700	0	20,934,235
29	1,573	26,126	(1)	0		1,573
30	317,428	295,205	1	22,224		317,428
31		239,401		0		

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR						
Line No.	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR Taxes Accrued (Account 236) (j)	BALANCE AT END OF YEAR Prepaid Taxes (Included in Account 165) (k)	DISTRIBUTION OF TAXES CHARGED Electric (Account 408.1, 409.1) (l)
32	1,009,062	789,685		219,377		1,009,062
33	664,254	664,254		0		
34	1,992,317	2,014,671	0	241,601	0	1,328,063
35				0		
36	60		(60)	0		51
37				0		
38	50	50		0		50
39				0		
40	100,000	100,000		0		20,000
41	975	975		0		123
42	101,085	101,025	(60)	0	0	20,224
43		2,310	(4,633)	0		
44	46,448	42,701		3,747		16,098
45		350	(178)	0		
46	9,910	9,671		239		3,435
47		1,249	(13,006)	0		
48	63,273	52,444		10,829		21,929
49		89,303	16,988	0		
50	1,119,287	1,244,525		(125,238)		387,927
51				0		
52	2,877	2,157		720		997
53		(14,004)	(14,004)	0		
54	234,843	(8,879)	(1,039,935)	0		81,393
55	17,276,344	17,277,550	1,054,060	1,052,854		5,987,700
56	18,752,982	18,699,377	(708)	943,151	0	6,499,479
57	646	1,286,515		0		665
58	5,621,364	4,248,584		1,372,780		3,800,945
59	(107)	1,537,207	1	0		
60	5,733,816	4,454,171	(1)	1,279,644		
61	11,355,719	11,526,477	0	2,652,424	0	3,801,610
62		7	(1)	0		

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR						
Line No.	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR Taxes Accrued (Account 236) (j)	BALANCE AT END OF YEAR Prepaid Taxes (Included in Account 165) (k)	DISTRIBUTION OF TAXES CHARGED Electric (Account 408.1, 409.1) (l)
63	35	26	1	10		35
64		42		0		
65	215	165		50		215
66	250	240	0	60	0	250
40	132,018,452	135,775,232	(2,600,212)	31,879,207	4,233,606	72,189,619

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR			
Line No.	DISTRIBUTION OF TAXES CHARGED Extraordinary Items (Account 409.3) (m)	DISTRIBUTION OF TAXES CHARGED Adjustment to Ret. Earnings (Account 439) (n)	DISTRIBUTION OF TAXES CHARGED Other (o)
1			
2			541,199
3			7,437,567
4	0	0	7,978,766
5			(569,777)
6			3,315,012
7			(1,236)
8			972,208
9			
10			
11			2,651,275
12			2,543,657
13	0	0	8,911,139
14			(2,862)
15			10,664,248
16			(5,020)
17			799,999
18	0	0	11,456,365
19			
20			97,155
21			(7,910)
22			1,830,363
23			
24			166,826
25	0	0	2,086,434
26			4,462
27			8,838,940
28	0	0	8,843,402
29			
30			
31			
32			

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR			
Line No.	DISTRIBUTION OF TAXES CHARGED Extraordinary Items (Account 409.3) (m)	DISTRIBUTION OF TAXES CHARGED Adjustment to Ret. Earnings (Account 439) (n)	DISTRIBUTION OF TAXES CHARGED Other (o)
33			664,254
34	0	0	664,254
35			
36			9
37			
38			
39			
40			80,000
41			852
42	0	0	80,861
43			
44			30,350
45			
46			6,475
47			
48			41,344
49			
50			731,360
51			
52			1,880
53			
54			153,450
55			11,288,644
56	0	0	12,253,503
57			(19)
58			1,820,419
59			(107)
60			5,733,816
61	0	0	7,554,109
62			
63			
64			

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR			
Line No.	DISTRIBUTION OF TAXES CHARGED Extraordinary Items (Account 409.3) (m)	DISTRIBUTION OF TAXES CHARGED Adjustment to Ret. Earnings (Account 439) (n)	DISTRIBUTION OF TAXES CHARGED Other (o)
65			
66	0	0	0
40	0	0	59,828,833

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)
1	Electric Utility					
2	3%					
3	10%					
4	Fed ITC	27,621,711			411.4	520,104
5	Idaho ITC	986,793	411.4	52	411.4	26,510
8	TOTAL Electric (Enter Total of lines 2 thru 7)	28,608,504		52		546,614
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)					
10	Gas Property (100%					
11	Idaho ITC	175,941	411.4	8	411.4	4,729
47	OTHER TOTAL	175,941		8		4,729
48	GRAND TOTAL	28,784,445				

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)				
Line No.	Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
1				
2				
3				
4		27,101,607		
5		960,335		
8		28,061,942		
9				
10				
11		171,220		
47		171,220		
48		28,233,162		

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

OTHER DEFERRED CREDITS (Account 253)

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	[(a)](#) Deferred Gas Exchange	1,406,250	495	5,625,000	5,625,000	1,406,250
2	Bills Pole Rentals	694,497	454	1,360,857	1,332,721	666,361
3	Defer Comp Active Execs	7,540,648	128	1,417,983	1,671,243	7,793,908
4	Unbilled Revenue	3,568,598	908	26,788,651	27,874,080	4,654,027
5	[(b)](#) Decoupling Deferred Credits	23,415,084	182, 456, 495	18,690,227	3,741,826	8,466,683
6	[(c)](#) Reg Liability-COVID-19 Deferral	7,749,100				7,749,100
7	[(d)](#) WA REC Deferrals	868,759	186, 431	1,107,117	238,358	0
8	Timber Harvest	226,796				226,796
9	[(e)](#) Other Def Cr - FISERV	791,667	903	416,667	495,702	870,702
10	[(f)](#) Accts Pay - Software Licenses - LT	2,093,461	242	1,658,850	642,885	1,077,496
11	Misc. Deferred Credits	47,742	186, 903, 242	156,225	115,403	6,920
47	TOTAL	48,402,602		57,221,577	41,737,218	32,918,243

FOOTNOTE DATA

(a) Concept: DescriptionOfOtherDeferredCredits
FortisBC and Avista exchange volumes of gas on a firm delivery basis during different time periods. Amortization is recorded monthly every year. This contract ends April 2025.
(b) Concept: DescriptionOfOtherDeferredCredits
Washington and Idaho Decoupling orders for electric and natural gas thru March 31, 2025. Oregon approved similar to Washington and Idaho beginning March 1, 2016. Decoupling revenue deferrals are recognized during the period they occur, subject to certain limitations. Revenue is expected to be collected within 24 months of the deferral.
(c) Concept: DescriptionOfOtherDeferredCredits
Deferral of COVID-19 costs as per Idaho PUC Order No. 34718, Oregon PUC Order No. 20-401, Docket UM 2069 and WA UTC Order No. 01, Dockets UE-200407 and UG-200408.
(d) Concept: DescriptionOfOtherDeferredCredits
WA Docket UE-190334, Schedule 98.
(e) Concept: DescriptionOfOtherDeferredCredits
Other Deferred Credit-Fiserv
(f) Concept: DescriptionOfOtherDeferredCredits
Deferred Liability for Software Licenses

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)	CHANGES DURING YEAR Amounts Debited to Account 410.2 (e)	CHANGES DURING YEAR Amounts Credited to Account 411.2 (f)
1	Account 282					
2	Electric	422,767,286	13,309,876	645,700		
3	Gas	152,279,809	2,154,316	1,414,058		
4	Other (Specify)	61,774,590	(5,499,651)	167,210		
5	Total (Total of lines 2 thru 4)	636,821,685	9,964,541	2,226,968		
6						
7						
8						
9	TOTAL Account 282 (Total of Lines 5 thru 8)	636,821,685	9,964,541	2,226,968		
10	Classification of TOTAL					
11	Federal Income Tax	636,821,685	9,964,541	2,226,968		
12	State Income Tax					
13	Local Income Tax					

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

Line No.	ADJUSTMENTS Debits Account Credited (g)	ADJUSTMENTS Debits Amount (h)	ADJUSTMENTS Credits Account Debited (i)	ADJUSTMENTS Credits Amount (j)	Balance at End of Year (k)
1					
2			182.3	3,767,273	439,198,735
3			182.3	4,017,114	157,037,181
4			182.3	876,225	56,983,954
5				8,660,612	653,219,870
6					
7					
8					
9				8,660,612	653,219,870
10					
11				8,660,612	653,219,870
12					
13					

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)	CHANGES DURING YEAR Amounts Debited to Account 410.2 (e)	CHANGES DURING YEAR Amounts Credited to Account 411.2 (f)
1	Account 283					
2	Electric					
3	Electric	46,111,868	5,624,777	796,200	96,298	19,353
9	TOTAL Electric (Total of lines 3 thru 8)	46,111,868	5,624,777	796,200	96,298	19,353
10	Gas					
11	Gas	29,349,984	129,174	8,267,349	1,093,165	4,840
17	TOTAL Gas (Total of lines 11 thru 16)	29,349,984	129,174	8,267,349	1,093,165	4,840
18	TOTAL Other	209,660,847	803,918	3,215,328	73,800	
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	285,122,699	6,557,869	12,278,877	1,263,263	24,193
20	Classification of TOTAL					
21	Federal Income Tax	285,122,699	6,557,869	12,278,877	1,263,263	24,193
22	State Income Tax					
23	Local Income Tax					

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

Line No.	ADJUSTMENTS Debits Account Credited (g)	ADJUSTMENTS Debits Amount (h)	ADJUSTMENTS Credits Account Debited (i)	ADJUSTMENTS Credits Amount (j)	Balance at End of Year (k)
1					
2					
3	182/254	861,711			50,155,679
9		861,711			50,155,679
10					
11	182/254	166,602			22,133,532
17		166,602			22,133,532
18	182/254	22,901,733			184,421,504
19		23,930,046		0	256,710,715
20					
21		23,930,046			256,710,715
22					
23					

NOTES

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

OTHER REGULATORY LIABILITIES (Account 254)

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	(a) Idaho Investment Tax Credit	10,038,667		2,933,191	0	7,105,476
2	(b) Interest Rate Swaps	24,204,062	427, 175	8,321,364	7,868,930	23,751,628
3	Nez Perce	462,284		22,008		440,276
4	Idaho Earnings Test	686,970		114,495		572,475
5	(c) Decoupling Rebate	8,378,370	495, 182	19,020,610	28,640,582	17,998,342
6	(d) WA ERM	5,269,902		5,269,902	0	0
7	(e) Deferred Federal ITC - Varies	7,538,104		333,802	0	7,204,302
8	(f) Plant Excess Deferred	323,181,031		21,561,802	0	301,619,229
9	Reg Liability MDM System	678,843		678,843	0	0
10	(g) DSM Tariff Rider	11,581,998	182, 431, 908	17,700,901	11,105,947	4,987,044
11	(h) Low Income Energy Assistance	7,940,357	242, 908	28,801,667	26,595,334	5,734,024
12	(i) Reg Liability - OR Tax Strategy Deferral	1,283,006	254, 407	757,068	43,628	569,566
13	(j) Reg Liability - Tax Reform Amortization	184,460	407, 431	50,873	5,718	139,305
14	(k) Reg Liability - WA Rev Def of Power Supply	971,669		990,053	18,384	0
15	(l) Reg Liability - Energy Efficiency Assistance	986,890	254	285,347	13,055	714,598
16	(m) Reg Liability - COVID-19 Deferral	4,124,859	254, 407	1,718,235	400,750	2,807,374
17	(n) Reg Liability - Tax Customer Credit	107,138,114	190, 410	60,737,909	9,853,658	56,253,863
18	(o) CS2 Insurance Proceeds Deferral	804,403	254	0	62,834	867,237
19	(p) Regulatory Liabilities - Other	9,869,668	190	0	1,277,935	11,147,603
20	(q) Reg Liability - CCA	0	254	0	37,231,122	37,231,122

OTHER REGULATORY LIABILITIES (Account 254)

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
21	(r) Insurance Balancing Account	0	182, 407	14,256	29,110	14,854
22	Misc. Regulatory Liabilities	85,888	143, 411	1,571,925	1,561,634	75,597
41	TOTAL	525,409,545		170,884,251	124,708,621	479,233,915

FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Not amortized.

(b) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Mark-to-Market gains and losses for interest rate swap derivatives. Upon settlement, amortization of Regulatory Assets and Liabilities as a component of interest expense over the term of the associated debt.

(c) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Decoupling rebates are recognized during the period they occur, subject to certain limitations. Rebates are returned to customers within 24 months of the deferral.

(d) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

The Washington Energy Recovery Mechanism allows Avista to periodically increase or decrease electric rates. This accounting method tracks differences between actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base rates. Avista files yearly on or before April 1 for prudence review by the commission.

(e) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Noxon ITC - 65yr amort, ends 2077

Community Solar ITC - 20yr amort, ends 2035

Nine Mile ITC - 65yr amort, ends 2080.

(f) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Amortized over remaining book life of plant, estimated 36 years.

(g) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

WA Orders Dockets UE-190912 and UG-190920, Idaho Docket AVU-E-18-12 and AVU-G-18-08, OR Order No. 19-424.

(h) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

WA Docket No UE-190912, UG-190920

ID Docket No AVU-E-18-12, AVU-G-18-08

OR RG 81, Docket No ADV 1063 (Advice No. 19-10-G)

(i) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

OR Docket No UM 2124. Deferral of associated state tax savings.

(j) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

WA Docket No. UG-170486

ID Docket No. AVU-E-23-01

(k) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Deferred liability for over-collection of authorized power supply cost revenue from Washington retail customers.

(l) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Avista's contribution in the Energy Assistance Fund as per ID Settlement Stipulation Case # AVU-E-19-04

(m) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Deferral of COVID-19 costs as per Idaho PUC Order No. 34718, OR PUC Order No. 20-401, Docket UM 2069 and WA UTC Order No. 01, Dockets UE-200407 and UG-200408.

(n) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

WA Order 01, Dockets No UE-200895 and UG-200896, ID Case Nos. AVU-E-20-12 and AVU-G-20-07 Order No. 34906, and OR Docket No UM 2124 Order No 21-131.

Accounting method change for federal income tax from normalization flow-through for Industry Director Directive No. 5 mixed service costs and meters.

(o) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Insurance proceeds for failed transformer at Coyote Springs per WA Order UE-210893 Order 01.

(p) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

State inome tax NOL carryforward will reverse over the period in which we are able to utilize the loss to offset taxable income on the ID, MT, and OR tax returns.
(q) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities
To defer costs of compliance with the Climate Commitment Act in accordance with WAC 480-100-203(3) and WAC 480-90-203(3). WA Docket No UG-220803.
(r) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities
To defer costs above or below the baseline in accordance with Order No 10/04 Docket Nos UE-220053, UE-210854, and UG-220054.

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

Electric Operating Revenues

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	425,258,195	414,822,725	4,020,329	4,153,697	366,450	361,606
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	343,522,797	338,656,420	3,159,672	3,200,915	45,341	44,578
5	Large (or Ind.) (See Instr. 4)	120,123,256	118,350,840	2,096,554	2,131,895	1,188	1,194
6	(444) Public Street and Highway Lighting	7,975,679	7,483,091	16,839	16,795	690	681
7	(445) Other Sales to Public Authorities	0	0	0	0	0	0
8	(446) Sales to Railroads and Railways	0	0	0	0	0	0
9	(448) Interdepartmental Sales	1,606,948	1,571,568	14,475	14,388	162	157
10	TOTAL Sales to Ultimate Consumers	898,486,875	880,884,644	9,307,869	9,517,690	413,831	408,216
11	(447) Sales for Resale	253,658,001	184,587,443	3,521,491	3,144,486		
12	TOTAL Sales of Electricity	1,152,144,876	1,065,472,087	12,829,360	12,662,176	413,831	408,216
13	(Less) (449.1) Provision for Rate Refunds	0	347,000	0	0		
14	TOTAL Revenues Before Prov. for Refunds	1,152,144,876	1,065,125,087	12,829,360	12,662,176	413,831	408,216
15	Other Operating Revenues						
16	(450) Forfeited Discounts	0	0				
17	(451) Miscellaneous Service Revenues	129,396	122,226				
18	(453) Sales of Water and Water Power	688,332	368,008				
19	(454) Rent from Electric Property	7,542,853	4,199,517				
20	(455) Interdepartmental Rents	0	0				

Electric Operating Revenues

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)
21	(456) Other Electric Revenues	2,198,927	67,308,760				
22	(456.1) Revenues from Transmission of Electricity of Others	30,969,981	30,339,137				
23	(457.1) Regional Control Service Revenues	0	0				
24	(457.2) Miscellaneous Revenues	0	0				
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	41,529,489	102,337,648				
27	TOTAL Electric Operating Revenues	1,193,674,365	1,167,462,735				

Line12, column (b) includes $ (6,081,121) of unbilled revenues.
Line12, column (d) includes (114,421) MWH relating to unbilled revenues

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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	01 Residential Service	3,921,898	394,716,078	346,375	11,322.6976	0.1006
2	02 Fixed-Income Senior and Disabled Residential Service	9,328	657,724	653	14,276.2134	0.0705
3	11 General Service	0	(61,202)	0		
4	12 Residential & Farm General Service	106,518	15,871,570	17,480	6,093.7034	0.149
5	21 Large General Service	0	(19,843)	0		
6	22 Residential and Farm Large General Service	39,617	3,918,241	71	558,641.4207	0.0989
7	30 Pumping Service	47	5,722	7	6,672.1001	0.1225
8	32 Residential and Farm Pumping Service	10,138	1,415,206	1,864	5,439.289	0.1396
9	48 Residential and Farm Area Lighting	2,954	1,291,490	0		0.4371
10	58 Tax Adjustment	0	11,472,813	0		
11	95 Optional Renewable Power	0	235,157	0		
41	TOTAL Billed Residential Sales	4,090,500	429,502,956	366,450	11,162.5051	0.105
42	TOTAL Unbilled Rev. (See Instr. 6)	(70,171)	(4,244,761)			0.0605
43	TOTAL	4,020,329	425,258,195	366,450	10,971.0165	0.1058

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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	11 General Service	1,083,432	127,520,194	41,787	25,927.6869	0.1177
2	13 Optional Commercial Electric Vehicle Rate - General Service	445	60,640	11	40,154.6183	0.1363
3	21 Large General Service	1,643,911	166,275,540	2,166	759,107.9261	0.1011
4	23 Optional Commercial Electric Vehicle Rate - Large General Service	1,016	122,476	3	348,429.0754	0.1205
5	25 Extra Large General Service	343,335	24,952,483	13	26,410,369.7989	0.0727
6	31 Pumping Service	115,881	11,412,038	1,361	85,112.8361	0.0985
7	47 Area Light	4,113	1,628,832	0		0.3961
8	49 Area Lighting	2,041	729,152	0		0.3572
9	58 Tax Adjustment	0	12,063,499	0		
10	95 Optional Renewable Power	0	139,120	0		
41	TOTAL Billed Small or Commercial	3,194,174	344,903,974	45,341	70,447.8066	0.108
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	(34,502)	(1,381,177)			0.04
43	TOTAL Small or Commercial	3,159,672	343,522,797	45,341	69,686.8618	0.1087

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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	11 General Service	11,527	1,319,053	217	53,139.4555	0.1144
2	21 Large General Service	149,500	14,797,441	110	1,354,988.9561	0.099
3	25 Extra Large General Service	1,864,256	95,869,368	21	88,774,078.4292	0.0514
4	30 Pumping Service	29,062	2,452,598	50	581,241.9924	0.0844
5	31 Pumping Service	47,613	4,811,830	673	70,720.7724	0.1011
6	32 Residential and Farm Pumping Service	4,176	412,482	117	35,797.6351	0.0988
7	47 Area Light	119	33,386	0		0.281
8	48 Residential and Farm Area Lighting	0	267	0		0.5624
9	49 Area Lighting	48	14,080	0		0.2955
10	58 Tax Adjustment	0	866,900	0		
11	95 Optional Renewable Power	0	1,036	0		
41	TOTAL Billed Large (or Ind.) Sales	2,106,301	120,578,441	1,188	1,772,980.6397	0.0572
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	(9,747)	(455,185)			0.0467
43	TOTAL Large (or Ind.)	2,096,554	120,123,256	1,188	1,764,776.0943	0.0573

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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	41 Company Owned Steet Light Service	2	323	0	20,766.396	0.1865
2	42 Company Owned Steet Light Service	14,007	7,341,825	589	23,780.9847	0.5242
3	44 Company Owned Steet Light Energy & Maintenance Service - High Pressure Sodium Vapor	403	73,532	24	16,986.4989	0.1823
4	45 Company Owned Steet Light Energy Service	694	68,698	12	57,793.4603	0.0991
5	46 Company Owned Steet Light Energy Service	1,733	215,077	65	26,455.6265	0.1241
6	58 Tax Adjustment	0	276,224	0		
41	TOTAL Billed Public Street and Highway Lighting	16,839	7,975,679	690	24,404.3478	0.4736
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	16,839	7,975,679	690	24,404.3478	0.4736

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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SALES OF ELECTRICITY BY RATE SCHEDULES

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)
31						
32						
33						
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41	TOTAL Billed Other Sales to Public Authorities					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	0	0	0		

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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SALES OF ELECTRICITY BY RATE SCHEDULES

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)
31						
32						
33						
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41	TOTAL Billed Sales To Railroads and Railways					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	0	0	0		

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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	01 Residential Service	191	18,951	15	12,981.8939	0.099
2	11 General Service	4,007	493,841	115	34,745.0743	0.1232
3	12 Residential & Farm General Service	1	211	0	7,773.57	0.1627
4	13 Optional Commercial Electric Vehicle Rate - General Service	226	32,024	10	23,335.2983	0.142
5	21 Large General Service	9,155	940,621	16	566,266.8544	0.1027
6	31 Pumping Service	766	71,816	5	161,229.0811	0.0938
7	32 Residential and Farm Pumping Service	39	4,027	1	38,839	0.1037
8	47 Area Light	86	42,851	0		0.4973
9	48 Residential and Farm Area Lighting	1	382	0		0.3891
10	49 Area Lighting	3	1,470	0		0.4486
11	58 Tax Adjustment	0	754	0		
41	TOTAL Billed Interdepartmental Sales	14,475	1,606,948	162	89,351.8519	0.111
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	14,475	1,606,948	162	89,351.8519	0.111

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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SALES OF ELECTRICITY BY RATE SCHEDULES

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)
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	0	0			

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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	9,422,289	904,567,998	413,831	22,768.4465	0.096
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	(114,420)	(6,081,123)			0.0531
43	TOTAL - All Accounts	9,307,869	898,486,875	413,831	22,491.9569	0.0965

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

SALES FOR RESALE (Account 447)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW) Average Monthly NCP Demand (e)	ACTUAL DEMAND (MW) Average Monthly CP Demand (f)
1	Altop Energy Trading	SF	Tariff 9			
2	Avangrid Renewables, LLC	SF	Tariff 9			
3	Avangrid Renewables, LLC	LF	[ay] Tariff 12			
4	Avangrid Renewables, LLC	[a] LF	Tariff 9			
5	Avangrid Renewables, LLC	[b] IF	Tariff 9			
6	BHE Power Watch, LLC	LF	[az] Tariff 12			
7	BP Energy Company	SF	Tariff 9			
8	Basin Electric Power Cooperative	SF	Tariff 9			
9	Bonneville Power Administration	SF	Tariff 9			
10	Bonneville Power Administration	LF	[ba] Tariff 12			
11	Bonneville Power Administration	[c] IF	Tariff 9			
12	Bonneville Power Administration	[d] IF	Tariff 9			
13	British Columbia Hydro and Power Authority	LF	[bb] Tariff 12			
14	Brookfield Energy Marketing LP	SF	Tariff 9			
15	Brookfield Energy Marketing LP	[e] IF	Tariff 9			
16	CP Energy Marketing (US) Inc.	SF	Tariff 9			
17	CP Energy Marketing (US) Inc.	[f] IF	Tariff 9			
18	California Independent System Operator Corporation	SF	Tariff 9			
19	Calpine Energy Services, LP	SF	Tariff 9			
20	Chelan County PUD No. 1	LF	[bc] Tariff 12			
21	Clatskanie Peoples PUD	SF	Tariff 9			
22	ConocoPhillips Company	SF	Tariff 9			
23	Constellation Energy Generation, LLC	SF	Tariff 9			
24	Constellation Energy Generation, LLC	[g] IF	Tariff 9			

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW) Average Monthly NCP Demand (e)	ACTUAL DEMAND (MW) Average Monthly CP Demand (f)
25	Dynasty Power, Inc.	SF	Tariff 9			
26	Dynasty Power, Inc.	[h] IF	Tariff 9			
27	EDF Trading North America, LLC	SF	Tariff 9			
28	EDF Trading North America, LLC	[i] IF	Tariff 9			
29	EDF Trading North America, LLC	SF	Tariff 9			
30	Energy Keepers, Inc.	SF	Tariff 9			
31	Energy Keepers, Inc.	[j] LF	Tariff 9			
32	Eugene Water Electric Board	SF	Tariff 9			
33	Franklin County PUD No. 1	SF	Tariff 9			
34	Grant County PUD No. 2	LF	[bd] Tariff 12			
35	Gridforce Energy Management, LLC	LF	[be] Tariff 12			
36	Guzman Energy, LLC	SF	Tariff 9			
37	Guzman Energy, LLC	[k] IF	Tariff 9			
38	Heartland Generation Ltd.	SF	Tariff 9			
39	Idaho Power Company	SF	Tariff 9			
40	Idaho Power Company	LF	[bf] Tariff 12			
41	Idaho Power Company	[l] LF	Tariff 9			
42	Idaho Power Company Balancing	SF	Tariff 9			
43	Idaho Power Company Balancing	[m] LF	Tariff 9			
44	Idaho Power Company Balancing	[n] IF	Tariff 9			
45	Idaho Power Company Balancing	[o] IF	Tariff 9			
46	Idaho Power Company Balancing	[p] IF	Tariff 9			
47	J. Aron & Company	SF	Tariff 9			
48	Kootenai Electric Cooperative	[q] IF	Tariff 9			
49	Macquarie Energy LLC	SF	Tariff 9			
50	Macquarie Energy LLC	[r] LF	Tariff 9			

SALES FOR RESALE (Account 447)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW) Average Monthly NCP Demand (e)	ACTUAL DEMAND (MW) Average Monthly CP Demand (f)
51	Mercuria Energy America, LLC	[s] IF	Tariff 9			
52	Mercuria Energy America, LLC	SF	Tariff 9			
53	Mizuho Securities USA Inc.	[t] OS	NA			
54	Morgan Stanley Capital Group Inc.	SF	Tariff 9			
55	Morgan Stanley Capital Group Inc.	[u] LF	Tariff 9			
56	Morgan Stanley Capital Group Inc.	[v] IF	Tariff 9			
57	Morgan Stanley Capital Group Inc.	SF	Tariff 9			
58	Morgan Stanley Capital Group Inc.	SF	Tariff 9			
59	NaturEner Power Watch, LLC	LF	[bg] Tariff 12			
60	Nevada Power Company	SF	Tariff 9			
61	NorthWestern Energy	SF	Tariff 9			
62	NorthWestern Energy	[w] LF	Tariff 9			
63	NorthWestern Energy	LF	[bh] Tariff 12			
64	NorthWestern Energy	[x] LF	Tariff 9			
65	NorthWestern Energy	[y] IF	Tariff 9			
66	PacifiCorp	SF	Tariff 9			
67	PacifiCorp	[z] IF	Tariff 9			
68	PacifiCorp	LF	[bi] Tariff 12			
69	PacifiCorp	[aa] IF	Tariff 9			
70	PacifiCorp	[ab] LF	Tariff 9			
71	Pend Oreille County Public Utility District #1	LF	Tariff 9			
72	Pend Oreille County Public Utility District #1	[ac] LF	Tariff 9			
73	Pend Oreille County Public Utility District #1	[ad] LF	Tariff 9			
74	Pend Oreille County Public Utility District #1	SF	Tariff 9			
75	Phillips 66 Energy Trading, LLC	SF	Tariff 9			

SALES FOR RESALE (Account 447)						
					ACTUAL DEMAND (MW)	ACTUAL DEMAND (MW)
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)	Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
76	Phillips 66 Energy Trading, LLC	[ae] IF	Tariff 9			
77	Portland General Electric	SF	Tariff 9			
78	Portland General Electric	LF	[bj] Tariff 12			
79	Portland General Electric	[af] IF	Tariff 9			
80	Portland General Electric	[ag] IF	Tariff 9			
81	Power Ex	SF	Tariff 9			
82	Power Ex	[ah] LF	Tariff 9			
83	Puget Sound Energy	[ai] LF	Tariff 9			
84	Puget Sound Energy	SF	Tariff 9			
85	Puget Sound Energy	LF	[bk] Tariff 12			
86	Puget Sound Energy	[aj] IF	Tariff 9			
87	Rainbow Energy Marketing	SF	Tariff 9			
88	Rainbow Energy Marketing	[ak] LF	Tariff 9			
89	Sacramento Municipal Utility District	LF	[bl] Tariff 12			
90	Seattle City Light	SF	Tariff 9			
91	Seattle City Light	[al] LF	Tariff 9			
92	Seattle City Light	[am] IF	Tariff 9			
93	Seattle City Light	LF	[bm] Tariff 12			
94	Shell Energy N.A.	SF	Tariff 9			
95	Shell Energy N.A.	[an] IF	Tariff 9			
96	Shell Energy N.A.	OS	Tariff 9			
97	Snohomish County PUD	SF	Tariff 9			
98	Sovereign Power	LF	Tariff 9			
99	Sovereign Power	[ao] LF	Tariff 9			
100	Tacoma Power	SF	Tariff 9			

SALES FOR RESALE (Account 447)						
Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW) Average Monthly NCP Demand (e)	ACTUAL DEMAND (MW) Average Monthly CP Demand (f)
101	Tacoma Power	(ap) LF	Tariff 9			
102	Tacoma Power	LF	(bn) Tariff 12			
103	Talen Energy Montana, LLC	(aq) LF	Tariff 9			
104	Tenaska Power Services Co.	(ar) LF	Tariff 9			
105	The Energy Authority	SF	Tariff 9			
106	The Energy Authority	(as) LF	Tariff 9			
107	TransAlta Energy Marketing	SF	Tariff 9			
108	TransAlta Energy Marketing	(at) LF	Tariff 9			
109	Vitol, Inc.	SF	Tariff 9			
110	Wells Fargo Securities, LLC	(au) OS	NA			
111	IntraCompany Wheeling	(av) LF				
112	IntraCompany Generation	(aw) LF				
113	California Independent System Operator Corporation	(ax) OS	Tariff 9			
15	Subtotal - RQ					
16	Subtotal-Non-RQ					
17	Total					

SALES FOR RESALE (Account 447)

Line No.	Megawatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ($) (h+i+j) (k)
1	3,200		202,276		202,276
2	114,800		6,767,366		6,767,366
3	14		1,085		1,085
4	164		9,815		9,815
5	7,816		0		0
6	5		201		201
7	220,554		11,960,142		11,960,142
8	1,400		50,960		50,960
9	156,950		12,737,834		12,737,834
10	55		2,567		2,567
11	62,143		4,489,296		4,489,296
12	121,152		0		0
13	16		1,184		1,184
14	26,533		878,024		878,024
15			6,169		6,169
16	75		2,250		2,250
17	13		590		590
18	4,181		317,595		317,595
19	26,920		1,900,933		1,900,933
20	11		1,345		1,345
21	778		47,061		47,061
22	53,158		4,356,249		4,356,249
23	31,381		2,397,559		2,397,559
24	72		555		555
25	25,561		2,594,907		2,594,907
26	156		12,898		12,898
27	10,338		507,270		507,270
28	318		14,568		14,568
29	0	(bo)760			760
30	13,885		1,070,835		1,070,835
31	975		71,551		71,551
32	4,011		316,902		316,902
33	4		0		0

SALES FOR RESALE (Account 447)					
Line No.	Megawatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ($) (h+i+j) (k)
34	18		983		983
35	447		34,708		34,708
36	4,049		305,097		305,097
37	6,565		622,414		622,414
38	75		7,500		7,500
39	275		34,200		34,200
40	43		2,240		2,240
41	2		114		114
42	400		21,100		21,100
43	10,121		857,956		857,956
44	255		0		0
45	86,718		0		0
46	121,002		0		0
47	274		31,535		31,535
48	495		30,636		30,636
49	36,392		1,982,419		1,982,419
50	1,460		183,751		183,751
51	249		19,071		19,071
52	14,000		1,423,100		1,423,100
53	0			11,931,625	11,931,625
54	386,264		19,059,884		19,059,884
55	5,367		424,104		424,104
56	365,097		25,049,365		25,049,365
57	0	(bp)275,940			275,940
58	0	(bq)275,940			275,940
59	25		1,775		1,775
60	1,050		110,375		110,375
61	16,233		1,956,765		1,956,765
62	48		3,512		3,512
63	5		428		428
64	9,014		690,916		690,916
65	90,086		0		0
66	232,560		23,897,675		23,897,675

SALES FOR RESALE (Account 447)

Line No.	Megawatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ($) (h+i+j) (k)
67	49,283		0		0
68	33		4,250		4,250
69	1,816		93,858		93,858
70	6,010		460,611		460,611
71	0	[br]511,006			511,006
72	11,692		849,146		849,146
73	44		3,929		3,929
74	5,663		817,525		817,525
75	10,550		614,236		614,236
76	3,553		170,032		170,032
77	108,263		11,440,822		11,440,822
78	34		2,356		2,356
79	660		47,285		47,285
80	2,051		126,204		126,204
81	381,983		22,697,641		22,697,641
82	14,356		707,286		707,286
83	15,024		1,151,527		1,151,527
84	55,935		4,488,653		4,488,653
85	18		1,670		1,670
86	3,707		205,636		205,636
87	12,682		993,218		993,218
88	431		26,565		26,565
89	32		2,034		2,034
90	37,585		2,394,338		2,394,338
91	635		40,340		40,340
92	8		458		458
93	6		387		387
94	112,642		8,010,476		8,010,476
95	116		7,703		7,703
96				[bt]6,000	6,000
97	35,580		3,324,903		3,324,903
98	0	[bs]148,528			148,528

SALES FOR RESALE (Account 447)					
Line No.	Megawatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ($) (h+i+j) (k)
99	15,167		926,987		926,987
100	4,240		276,750		276,750
101	1,553		100,417		100,417
102	14		463		463
103	9,014		690,916		690,916
104	19		178		178
105	96,777		6,585,535		6,585,535
106	271		21,625		21,625
107	236,859		16,007,509		16,007,509
108	197		18,548		18,548
109	11,760		611,932		611,932
110	0			14,517,377	14,517,377
111			(35,503,866)	35,503,866	0
112				1,173,595	1,173,595
113				13,421,671	13,421,671
15					0
16	3,521,491	1,212,174	175,891,693	76,554,134	253,658,001
17	3,521,491	1,212,174	175,891,693	76,554,134	253,658,001

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses effective 01/01/2016-12/31/2024
(b) Concept: StatisticalClassificationCode
06/06/2023-12/31/2024 ETSR is an export resource associated with EIM.
(c) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(d) Concept: StatisticalClassificationCode
03/02/2022-12/31/2024 ETSR is an export resource associated with EIM.
(e) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(f) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(g) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(h) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(i) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(j) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses effective 01/01/2016-12/31/2024
(k) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(l) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses effective 01/01/2016-12/31/2024
(m) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses effective 01/01/2016-12/31/2024
(n) Concept: StatisticalClassificationCode
03/02/2022-12/31/2024 ETSR is an export resource associated with EIM.
(o) Concept: StatisticalClassificationCode
03/02/2022-12/31/2024 ETSR is an export resource associated with EIM.
(p) Concept: StatisticalClassificationCode
03/02/2022-12/31/2024 ETSR is an export resource associated with EIM.
(q) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(r) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses effective 07/18/2018-12/31/2024
(s) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(t) Concept: StatisticalClassificationCode
Financial SWAP
(u) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses effective 01/01/2016-12/31/2024

(v) Concept: StatisticalClassificationCode
Resource Contingent Bundled REC - Energy and Green Attributes 03/01/2019-12/31/2023
(w) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses effective 01/01/2016-12/31/2024
(x) Concept: StatisticalClassificationCode
NorthWestern Energy LLC sale expires December 31, 2025
(y) Concept: StatisticalClassificationCode
01/26/2022-12/31/2024 ETSR is an export resource associated with EIM.
(z) Concept: StatisticalClassificationCode
01/27/2022-12/31/2024 ETSR is an export resource associated with EIM.
(aa) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(ab) Concept: StatisticalClassificationCode
PacifiCorp sale expires December 31, 2025
(ac) Concept: StatisticalClassificationCode
Deviation Energy
(ad) Concept: StatisticalClassificationCode
Contract expires September 30, 2026
(ae) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(af) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(ag) Concept: StatisticalClassificationCode
Portland General Electric sale expires December 31, 2025
(ah) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses effective 05/01/2019-12/31/2024
(ai) Concept: StatisticalClassificationCode
Puget Sound Energy sale expires December 31, 2025
(aj) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(ak) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses effective 01/01/2016-12/31/2024
(al) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses effective 03/19/2008-12/31/2024
(am) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(an) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(ao) Concept: StatisticalClassificationCode
Deviation Energy
(ap) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses effective 03/19/2008-12/31/2024
(aq) Concept: StatisticalClassificationCode
Talen Energy Montana, LLC sale expires December 31, 2025
(ar) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses effective 01/01/2016-12/31/2024

(as) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses effective 01/01/2016-12/31/2024
(at) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses effective 01/01/2016-12/31/2024
(au) Concept: StatisticalClassificationCode
Financial SWAP
(av) Concept: StatisticalClassificationCode
Intra Company Wheeling
(aw) Concept: StatisticalClassificationCode
Intra Company Generation - Sale of Ancillary Services
(ax) Concept: StatisticalClassificationCode
Energy Imbalance Market (EIM) Sales
(ay) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement
(az) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement
(ba) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement
(bb) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement
(bc) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement
(bd) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement
(be) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement
(bf) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement
(bg) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement
(bh) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement
(bi) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement
(bj) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement
(bk) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement
(bl) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement
(bm) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement
(bn) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement
(bo) Concept: DemandChargesRevenueSalesForResale
Reserves
(bp) Concept: DemandChargesRevenueSalesForResale

Capacity
(bq) Concept: DemandChargesRevenueSalesForResale
Capacity
(br) Concept: DemandChargesRevenueSalesForResale
Contract expires September 30, 2026
(bs) Concept: DemandChargesRevenueSalesForResale
Sovereign Power contract terminates September 30, 2026
(bt) Concept: OtherChargesRevenueSalesForResale
Pondage

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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	177,149	342,883
5	(501) Fuel	46,052,299	41,707,542
6	(502) Steam Expenses	4,221,985	3,674,482
7	(503) Steam from Other Sources	0	0
8	(Less) (504) Steam Transferred-Cr.	0	0
9	(505) Electric Expenses	754,146	884,248
10	(506) Miscellaneous Steam Power Expenses	6,447,460	5,888,310
11	(507) Rents	0	0
12	(509) Allowances	662,437	0
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	58,315,476	52,497,465
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	408,706	704,474
16	(511) Maintenance of Structures	869,388	898,565
17	(512) Maintenance of Boiler Plant	7,090,052	6,596,152
18	(513) Maintenance of Electric Plant	849,384	883,060
19	(514) Maintenance of Miscellaneous Steam Plant	1,345,536	786,396
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	10,563,066	9,868,647
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	68,878,542	62,366,112
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	0	0
25	(518) Fuel	0	0
26	(519) Coolants and Water	0	0
27	(520) Steam Expenses	0	0
28	(521) Steam from Other Sources	0	0
29	(Less) (522) Steam Transferred-Cr.	0	0
30	(523) Electric Expenses	0	0

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
31	(524) Miscellaneous Nuclear Power Expenses	0	0
32	(525) Rents	0	0
33	TOTAL Operation (Enter Total of lines 24 thru 32)	0	0
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	0	0
36	(529) Maintenance of Structures	0	0
37	(530) Maintenance of Reactor Plant Equipment	0	0
38	(531) Maintenance of Electric Plant	0	0
39	(532) Maintenance of Miscellaneous Nuclear Plant	0	0
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	0	0
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)	0	0
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	2,459,290	2,724,681
45	(536) Water for Power	1,184,579	1,223,862
46	(537) Hydraulic Expenses	9,863,917	9,475,818
47	(538) Electric Expenses	6,629,557	6,827,422
48	(539) Miscellaneous Hydraulic Power Generation Expenses	2,203,306	1,731,229
49	(540) Rents	7,611,335	7,200,284
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	29,951,984	29,183,296
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	714,032	819,291
54	(542) Maintenance of Structures	498,079	1,044,569
55	(543) Maintenance of Reservoirs, Dams, and Waterways	497,535	888,287
56	(544) Maintenance of Electric Plant	3,128,062	3,607,944
57	(545) Maintenance of Miscellaneous Hydraulic Plant	663,385	752,814
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	5,501,093	7,112,905
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	35,453,077	36,296,201
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	893,882	379,621

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
63	(547) Fuel	116,227,146	171,864,307
64	(548) Generation Expenses	3,899,765	2,572,735
64.1	(548.1) Operation of Energy Storage Equipment	0	0
65	(549) Miscellaneous Other Power Generation Expenses	945,276	779,929
66	(550) Rents	103,105	87,122
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	122,069,174	175,683,714
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	768,609	751,930
70	(552) Maintenance of Structures	138,993	93,800
71	(553) Maintenance of Generating and Electric Plant	2,012,409	3,975,265
71.1	(553.1) Maintenance of Energy Storage Equipment	0	0
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	862,263	535,519
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	3,782,274	5,356,514
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	125,851,448	181,040,228
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	209,295,625	191,412,443
76.1	(555.1) Power Purchased for Storage Operations	7,132,090	252,740
77	(556) System Control and Load Dispatching	764,664	1,044,735
78	(557) Other Expenses	38,247,947	43,909,712
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	255,440,326	236,619,630
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	485,623,393	516,322,171
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,084,569	1,947,022
85	(561.1) Load Dispatch-Reliability	45,236	18,859
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,503,318	1,727,109
87	(561.3) Load Dispatch-Transmission Service and Scheduling	965,836	916,919
88	(561.4) Scheduling, System Control and Dispatch Services	0	0
89	(561.5) Reliability, Planning and Standards Development	565,721	596,438
90	(561.6) Transmission Service Studies	0	3,944

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
91	(561.7) Generation Interconnection Studies	0	5,704
92	(561.8) Reliability, Planning and Standards Development Services	0	0
93	(562) Station Expenses	397,216	455,206
93.1	(562.1) Operation of Energy Storage Equipment	0	0
94	(563) Overhead Lines Expenses	324,854	524,834
95	(564) Underground Lines Expenses	0	0
96	(565) Transmission of Electricity by Others	19,063,436	20,220,629
97	(566) Miscellaneous Transmission Expenses	4,242,693	4,423,684
98	(567) Rents	97,830	89,654
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	29,290,709	30,930,002
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	369,375	423,695
102	(569) Maintenance of Structures	572,864	707,438
103	(569.1) Maintenance of Computer Hardware	0	0
104	(569.2) Maintenance of Computer Software	0	0
105	(569.3) Maintenance of Communication Equipment	0	0
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant	0	0
107	(570) Maintenance of Station Equipment	1,160,838	1,209,445
107.1	(570.1) Maintenance of Energy Storage Equipment	0	0
108	(571) Maintenance of Overhead Lines	2,198,739	2,223,133
109	(572) Maintenance of Underground Lines	965	773
110	(573) Maintenance of Miscellaneous Transmission Plant	72,128	84,498
111	TOTAL Maintenance (Total of Lines 101 thru 110)	4,374,909	4,648,982
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	33,665,618	35,578,984
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision	0	0
116	(575.2) Day-Ahead and Real-Time Market Facilitation	0	0
117	(575.3) Transmission Rights Market Facilitation	0	0
118	(575.4) Capacity Market Facilitation	0	0
119	(575.5) Ancillary Services Market Facilitation	0	0
120	(575.6) Market Monitoring and Compliance	0	0

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
121	(575.7) Market Facilitation, Monitoring and Compliance Services	0	0
122	(575.8) Rents	0	0
123	Total Operation (Lines 115 thru 122)	0	0
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements	0	0
126	(576.2) Maintenance of Computer Hardware	0	0
127	(576.3) Maintenance of Computer Software	0	0
128	(576.4) Maintenance of Communication Equipment	0	0
129	(576.5) Maintenance of Miscellaneous Market Operation Plant	0	0
130	Total Maintenance (Lines 125 thru 129)	0	0
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	0	0
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	4,183,113	4,538,302
135	(581) Load Dispatching	0	0
136	(582) Station Expenses	945,603	934,752
137	(583) Overhead Line Expenses	3,151,705	2,894,198
138	(584) Underground Line Expenses	2,546,406	1,566,750
138.1	(584.1) Operation of Energy Storage Equipment	0	0
139	(585) Street Lighting and Signal System Expenses	6,950	5,888
140	(586) Meter Expenses	2,133,258	2,170,353
141	(587) Customer Installations Expenses	801,450	859,014
142	(588) Miscellaneous Expenses	9,401,777	7,747,059
143	(589) Rents	258,811	196,608
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	23,429,073	20,912,924
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,361,055	1,632,916
147	(591) Maintenance of Structures	411,657	593,149
148	(592) Maintenance of Station Equipment	779,672	887,699
148.1	(592.2) Maintenance of Energy Storage Equipment	0	0
149	(593) Maintenance of Overhead Lines	27,486,692	26,152,322
150	(594) Maintenance of Underground Lines	861,884	756,582

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
151	(595) Maintenance of Line Transformers	443,255	520,693
152	(596) Maintenance of Street Lighting and Signal Systems	91,567	115,351
153	(597) Maintenance of Meters	60,470	57,877
154	(598) Maintenance of Miscellaneous Distribution Plant	1,099,461	981,461
155	TOTAL Maintenance (Total of Lines 146 thru 154)	32,595,713	31,698,050
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	56,024,786	52,610,974
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	135,418	130,813
160	(902) Meter Reading Expenses	643,428	736,380
161	(903) Customer Records and Collection Expenses	8,464,586	8,085,755
162	(904) Uncollectible Accounts	5,102,188	42,879
163	(905) Miscellaneous Customer Accounts Expenses	277,721	259,554
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	14,623,341	9,255,381
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	0	0
168	(908) Customer Assistance Expenses	31,870,071	33,220,677
169	(909) Informational and Instructional Expenses	866,879	899,673
170	(910) Miscellaneous Customer Service and Informational Expenses	229,071	124,273
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	32,966,021	34,244,623
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	0	0
175	(912) Demonstrating and Selling Expenses	43,646	108,681
176	(913) Advertising Expenses	0	0
177	(916) Miscellaneous Sales Expenses	0	0
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	43,646	108,681
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
181	(920) Administrative and General Salaries	32,491,999	31,951,930
182	(921) Office Supplies and Expenses	3,924,958	4,208,908
183	(Less) (922) Administrative Expenses Transferred-Credit	114,022	95,466
184	(923) Outside Services Employed	14,933,869	14,506,894
185	(924) Property Insurance	2,806,701	2,435,764
186	(925) Injuries and Damages	10,784,299	10,487,107
187	(926) Employee Pensions and Benefits	28,096,654	37,144,003
188	(927) Franchise Requirements	1,200	1,200
189	(928) Regulatory Commission Expenses	8,387,545	6,789,206
190	(929) (Less) Duplicate Charges-Cr.	0	0
191	(930.1) General Advertising Expenses	0	0
192	(930.2) Miscellaneous General Expenses	5,644,865	5,342,709
193	(931) Rents	938,930	778,114
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	107,896,998	113,550,369
195	Maintenance		
196	(935) Maintenance of General Plant	14,630,422	14,984,639
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	122,527,420	128,535,008
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	745,474,225	776,655,822

PURCHASED POWER (Account 555)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)
1	Adams Nielson Solar, LLC	LU	PURPA				36,961
2	Altop Energy Trading	SF	Tariff 9				1,200
3	[(a)] Arizona Public Service Company	OS	APS OATT				
4	Avangrid Renewables, LLC	SF	Tariff 9				38,231
5	[(b)] Avangrid Renewables, LLC	LF	NWPP				6
6	[(c)] Avangrid Renewables, LLC	IF	Tariff 9				13,716
7	BP Energy	SF	Tariff 9				4,800
8	[(d)] Bonneville Power Administration	OS	BPA OATT				
9	[(e)] Bonneville Power Administration	LF	Tariff 8				440
10	Bonneville Power Administration	SF	Tariff 9				116,145
11	[(f)] Bonneville Power Administration	LF	NWPP				140
12	[(g)] Bonneville Power Administration	OS	BPA OATT				
13	[(h)] Bonneville Power Administration	IF	Tariff 9				23,601
14	[(i)] Bonneville Power Administration	OS	BPA OATT				
15	[(j)] Bonneville Power Administration	OS	BPA OATT				
16	[(k)] Bonneville Power Administration	IF	Tariff 9				96,717
17	Brookfield Energy Marketing LP	SF	Tariff 9				1,443
18	CP Energy Marketing (US) Inc.	SF	Tariff 9				1,300

PURCHASED POWER (Account 555)							
					Actual Demand (MW)	Actual Demand (MW)	
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)	Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)
19	California Independent System Operator	SF	Tariff 9				51,155
20	Calpine Energy Services, LP	SF	Tariff 9				175
21	Chelan County PUD	IU	Rocky Reach				22,575
22	(l) Chelan County PUD	IU	Rocky Reach				(23,686)
23	Chelan County PUD	SF	Tariff 9				2,800
24	(m) Chelan County PUD	LF	NWPP				5
25	Chelan County PUD	IU	Chelan Sys				351,170
26	City of Spokane	IU	PURPA				38,502
27	City of Spokane	IU	PURPA				124,696
28	Clark Fork Hydro	LU	PURPA				635
29	Clatskanie PUD	SF	Tariff 9				190
30	Clearwater Paper Company	IU	PURPA				425,877
31	Community Solar	LU	PURPA				478
32	ConocoPhillips Company	SF	Tariff 9				10,200
33	Constellation Energy Generation, LLC	SF	Tariff 9				5,736
34	Deep Creek Energy, LLC	IU	PURPA				50
35	Douglas County PUD No. 1	LU	Wells				379,055
36	(n) Douglas County PUD No. 1	LF	NWPP				1
37	Douglas County PUD No. 1	EX	Tariff 9				
38	Dynasty Power, Inc.	SF	Tariff 9				41,188
39	East, South, Quincy Columbia Basin Irrigation Districts	LU	PURPA				22,586
40	EDF Trading No America	SF	Tariff 9				9,015
41	Enel X North America, Inc.	LU	PURPA				5
42	Energy Keepers, Inc.	SF	Tariff 9				19,913
43	Eugene Water & Electric Board	SF	Tariff 9				2,021
44	Ford Hydro Limited Partnership	LU	PURPA				3,093

PURCHASED POWER (Account 555)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)
45	Grant County PUD No. 2	LU	Priest Rapids				255,042
46	(o) Grant County PUD No. 2	LF	NWPP				9
47	Grant County PUD No. 2	EX	FERC #104				
48	(p) Gridforce Energy Management, LLC	LF	NWPP				6
49	Guzman Energy, LLC	SF	Tariff 9				2,408
50	Heartland Generation Ltd.	SF	Tariff 9				4,642
51	Hydro Technology Systems	IU	PURPA				9,528
52	Idaho County Power & Light	LU	PURPA				1,267
53	(q) Idaho Power Company	OS	Idaho Power Co OATT				
54	Idaho Power Company	SF	Tariff 9				44,154
55	(r) Idaho Power Company	LF	Tariff 9				96
56	(s) Idaho Power Company Balancing	IF	Tariff 9				1,024
57	(t) Idaho Power Company Balancing	IF	Tariff 9				341,750
58	(u) Inland Power & Light Company	RQ	208				155
59	J. Aron & Company, LLC	SF	Tariff 9				274
60	Kootenai Electric Cooperative	EX	Tariff 8				
61	Macquarie Energy, LLC	SF	Tariff 9				36,730
62	Mercuria Energy America, LLC	SF	Tariff 9				1,216
63	(v) Mizuho Securities USA, Inc.	OS	NA				
64	Morgan Stanley Capital Group	SF	Tariff 9				20,600
65	Nevada Power Company	SF	Tariff 9				100
66	(w) Nevada Power Company	LF	Tariff 9				1
67	NorthWestern Energy	SF	Tariff 9				26,785

PURCHASED POWER (Account 555)							
					Actual Demand (MW)	Actual Demand (MW)	
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)	Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)
68	(x) NorthWestern Energy	LF	NWPP				16
69	(y) NorthWestern Energy	IF	Tariff 9				4,711
70	(z) NorthWestern Energy	IF	Tariff 9				221,363
71	(aa) NorthWestern Energy	OS	NorthWestern Energy OATT				
72	PacifiCorp	SF	Tariff 9				1,415
73	(ab) PacifiCorp	IF	Tariff 9				95,771
74	(ac) PacifiCorp	LF	NWPP				31
75	(ad) PacifiCorp	LF	Tariff 9				1
76	(ae) PacifiCorp	OS	PacifiCorp OATT				
77	Palouse Wind, LLC	LU	PPA				294,887
78	Pend Oreille County PUD No. 1	SF	Pend O'				42,481
79	(af) Pend Oreille County PUD No. 1	LF	Pend O'				7,457
80	Pend Oreille County PUD No. 1	LF	Pend O'				301
81	Portland General Electric Company	EX	Tariff 9				
82	Portland General Electric Company	SF	Tariff 9				5,160
83	(ag) Portland General Electric Company	LF	NWPP				41
84	(ah) Portland General Electric Company	LF	Tariff 9				2,102
85	(ai) Portland General Electric Company	OS	Portland General OATT				
86	Powerex Corp	SF	Tariff 9				4,850
87	Puget Sound Energy	SF	Tariff 9				22,387
88	(aj) Puget Sound Energy	LF	NWPP				39

PURCHASED POWER (Account 555)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)
89	(ak) Puget Sound Energy	LF	Tariff 9				278
90	(al) Puget Sound Energy	OS	Puget Sound Energy OATT				
91	(am) Puget Sound Energy	OS	Tariff 9				
92	Rainbow Energy Marketing Co.	SF	Tariff 9				60,140
93	Rathdrum Power, LLC	LU	Lancaster				1,806,400
94	Rattlesnake Flat, LLC	LU	PPA				343,410
95	Sacramento Municipal Utility District	SF	Tariff 9				270
96	Seattle City Light	SF	Tariff 9				8,750
97	(an) Seattle City Light	LF	NWPP				14
98	Sheep Creek Hydro	IU	PURPA				5,473
99	Shell Energy	SF	Tariff 9				8,514
100	Snohomish County PUD No. 1	SF	Tariff 9				6,655
101	(ao) Sovereign Power	LF	Sovereign				8,134
102	Stimson Lumber	IU	PURPA				8,784
103	Tacoma Power	SF	Tariff 9				12,461
104	(ap) Tacoma Power	LF	NWPP				6
105	The City of Cove	LU	PURPA				2,114
106	The Energy Authority	SF	Tariff 9				18,717
107	TransAlta Energy Marketing	SF	Tariff 9				23,120
108	Turlock Irrigation District	SF	Tariff 9				663
109	Vitol Inc.	SF	Tariff 9				16,212
110	(aq) Wells Fargo Securities, LLC	OS	NA				
111	(ar) IntraCompany Generation Services	OS	OATT				
112	Other - Inadvertent Interchange	EX					

PURCHASED POWER (Account 555)							
					Actual Demand (MW)	Actual Demand (MW)	
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)	Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)
113	(as) California Independent System Operator	OS	Tariff 9				
15	TOTAL						5,601,050

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

PURCHASED POWER (Account 555)

Line No.	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES MegaWatt Hours Received (i)	POWER EXCHANGES MegaWatt Hours Delivered (j)	COST/SETTLEMENT OF POWER Demand Charges ($) (k)	COST/SETTLEMENT OF POWER Energy Charges ($) (l)	COST/SETTLEMENT OF POWER Other Charges ($) (m)	COST/SETTLEMENT OF POWER Total (k+l+m) of Settlement ($) (n)
1					1,556,428		1,556,428
2					68,800		68,800
3						0	0
4					2,412,851		2,412,851
5					472		472
6							0
7					64,500		64,500
8						(502,871)	(502,871)
9							0
10					4,565,427		4,565,427
11					9,019		9,019
12						47,401	47,401
13					1,340,218		1,340,218
14						264	264
15						1,302	1,302
16							0
17					124,621		124,621
18					92,250		92,250
19					3,001,346		3,001,346
20					21,875		21,875
21							0
22							0
23					183,428		183,428
24					361		361
25				15,466,880			15,466,880
26					1,938,259		1,938,259
27					5,886,485		5,886,485
28					41,380		41,380
29					2,550		2,550
30					10,433,987		10,433,987

PURCHASED POWER (Account 555)							
Line No.	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES MegaWatt Hours Received (i)	POWER EXCHANGES MegaWatt Hours Delivered (j)	COST/SETTLEMENT OF POWER Demand Charges ($) (k)	COST/SETTLEMENT OF POWER Energy Charges ($) (l)	COST/SETTLEMENT OF POWER Other Charges ($) (m)	COST/SETTLEMENT OF POWER Total (k+l+m) of Settlement ($) (n)
31							0
32					814,188		814,188
33					292,690		292,690
34					5,351		5,351
35				3,627,412			3,627,412
36					84		84
37			411,720				0
38					5,185,314		5,185,314
39					975,038		975,038
40					588,281		588,281
41							0
42					1,634,168		1,634,168
43					40,355		40,355
44					158,570		158,570
45				34,065,844			34,065,844
46					596		596
47						94,328	94,328
48					473		473
49					283,485		283,485
50					425,804		425,804
51					424,640		424,640
52					59,029		59,029
53						(373)	(373)
54					2,804,211		2,804,211
55					3,337		3,337
56							0
57							0
58					10,565		10,565
59					49,105		49,105
60							0

PURCHASED POWER (Account 555)

Line No.	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES MegaWatt Hours Received (i)	POWER EXCHANGES MegaWatt Hours Delivered (j)	COST/SETTLEMENT OF POWER Demand Charges ($) (k)	COST/SETTLEMENT OF POWER Energy Charges ($) (l)	COST/SETTLEMENT OF POWER Other Charges ($) (m)	COST/SETTLEMENT OF POWER Total (k+l+m) of Settlement ($) (n)
61					2,585,009		2,585,009
62					140,824		140,824
63						4,350,932	4,350,932
64					1,334,144		1,334,144
65					500		500
66					155		155
67					1,336,980		1,336,980
68					1,041		1,041
69					276,133		276,133
70							0
71						(245,932)	(245,932)
72					46,375		46,375
73							0
74					1,995		1,995
75					(177)		(177)
76						(48)	(48)
77					19,574,599		19,574,599
78					2,776,687		2,776,687
79					451,508		451,508
80					4,139		4,139
81		9,973	9,969				0
82					228,925		228,925
83					2,699		2,699
84					87,235		87,235
85						3,499	3,499
86					724,500		724,500
87					1,764,002		1,764,002
88					2,651		2,651
89					30,004		30,004
90						5,257	5,257

PURCHASED POWER (Account 555)							
Line No.	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES MegaWatt Hours Received (i)	POWER EXCHANGES MegaWatt Hours Delivered (j)	COST/SETTLEMENT OF POWER Demand Charges ($) (k)	COST/SETTLEMENT OF POWER Energy Charges ($) (l)	COST/SETTLEMENT OF POWER Other Charges ($) (m)	COST/SETTLEMENT OF POWER Total (k+l+m) of Settlement ($) (n)
91						8,560	8,560
92					5,538,203		5,538,203
93					30,466,404		30,466,404
94					10,349,387		10,349,387
95					14,140		14,140
96					320,662		320,662
97					914		914
98					226,497		226,497
99					474,188		474,188
100					183,375		183,375
101					613,916		613,916
102					313,557		313,557
103					374,845		374,845
104					430		430
105					91,319		91,319
106					1,276,188		1,276,188
107					1,573,266		1,573,266
108					29,735		29,735
109					1,578,790		1,578,790
110						2,781,158	2,781,158
111						1,173,595	1,173,595
112		1,852					0
113						25,255,222	25,255,222
15	0	11,825	421,689	53,160,136	130,295,285	32,972,294	216,427,715

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Energy Imbalance Charges.
(b) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(c) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
06/26/2023-12/31/2024 ETSR is an import resource associated with an EIM intertie with another EIM BAA, or a CISO intertie with the CISO.
(d) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Energy Imbalance Charges.
(e) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
BPA Self Supply for NITSA customers.
(f) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(g) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Ancillary Services - Spinning & Supplemental Reserves.
(h) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Financially Settled Transmission Losses.
(i) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Financial Inaccuracy Penalty.
(j) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Oversupply Charges.
(k) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
03/02/2022-12/31/2024 ETSR is an import resource associated with an EIM intertie with another EIM BAA, or a CISO intertie with the CISO.
(l) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Canadian Entitlement
(m) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(n) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(o) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(p) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(q) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Energy Imbalance Charges.
(r) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Financially Settled Transmission Losses.
(s) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
03/02/2022-12/31/2024 ETSR is an import resource associated with an EIM intertie with another EIM BAA, or a CISO intertie with the CISO.
(t) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
03/02/2022-12/31/2024 ETSR is an import resource associated with an EIM intertie with another EIM BAA, or a CISO intertie with the CISO.
(u) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Service to Deer Lake from Inland Power and Light. No demand charges associated with the agreement.

(v) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Financial SWAP.
(w) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Financially Settled Transmission Losses.
(x) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(y) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Financially Settled Transmission Losses.
(z) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
01/26/2022-12/31/2024 ETSR is an import resource associated with an EIM intertie with another EIM BAA, or a CISO intertie with the CISO.
(aa) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Energy Imbalance Charges.
(ab) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
01/27/2022-12/31/2024 ETSR is an import resource associated with an EIM intertie with another EIM BAA, or a CISO intertie with the CISO.
(ac) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(ad) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Financially Settled Transmission Losses.
(ae) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Energy Imbalance Charges.
(af) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Pend Oreille County PUD contract expires September 30, 2026.
(ag) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(ah) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Financially settled Transmission Losses.
(ai) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Energy Imbalance Charges.
(aj) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(ak) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Financially Settled Transmission Losses.
(al) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Energy Imbalance Charges.
(am) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Pondage.
(an) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(ao) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Sovereign contract terminates September 30, 2026.
(ap) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(aq) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Financial SWAP.
(ar) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Ancillary Services.
(as) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Energy Imbalance Market Purchases.

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

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

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)
1	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	FNO	FERC Trf No. 8	AVA.BPAT	AVA.SYS
2	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS	RS No. T1110		
3	Bonneville Power Administration	Bonneville Power Administration	Idaho Power Company	NF	FERC Trf No. 8		
4	Brookfield Renewable Trading and Marketing	NorthWestern Montana	Puget Sound Energy	NF	FERC Trf No. 8		
5	City of Spokane	City of Spokane	Avista Corporation	OLF	PURPA		
6	Consolidated Irrigation	Bonneville Power Administration	Consolidated Irrigation	LFP	FERC Trf No. 8	AVA.BPAT	AVA.SYS
7	Shell Energy North America	Bonneville Power Administration	NorthWestern Montana	NF	FERC Trf No. 8		
8	Shell Energy North America	NorthWestern Montana	Bonneville Power Administration	NF	FERC Trf No. 8		
9	Shell Energy North America	NorthWestern Montana	Grant County PUD	NF	FERC Trf No. 8		
10	Shell Energy North America	Idaho Power Company	Bonneville Power Administration	NF	FERC Trf No. 8		
11	Shell Energy North America	Idaho Power Company	NorthWestern Montana	NF	FERC Trf No. 8		
12	Shell Energy North America	Idaho Power Company	Grant County PUD	NF	FERC Trf No. 8		
13	Shell Energy North America	Idaho Power Company	PacifiCorp	NF	FERC Trf No. 8		
14	Deep Creek Hydro	Deep Creek Hydro	Avista Corporation	OLF	PURPA		
15	Dynasty Power	Bonneville Power Administration	Idaho Power Company	NF	FERC Trf No. 8		
16	Dynasty Power	Bonneville Power Administration	NorthWestern Montana	NF	FERC Trf No. 8		
17	Dynasty Power	Bonneville Power Administration	PacifiCorp	NF	FERC Trf No. 8		
18	Dynasty Power	NorthWestern Montana	Bonneville Power Administration	NF	FERC Trf No. 8		
19	Dynasty Power	Idaho Power Company	Bonneville Power Administration	NF	FERC Trf No. 8		
20	Dynasty Power	Idaho Power Company	PacifiCorp	SFP	FERC Trf No. 8		

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

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)
21	EDR Trading North America	Bonneville Power Administration	NorthWestern Montana	NF	FERC Trf No. 8		
22	EDR Trading North America	Bonneville Power Administration	NorthWestern Montana	SFP	FERC Trf No. 8		
23	EDR Trading North America	NorthWestern Montana	Bonneville Power Administration	NF	FERC Trf No. 8		
24	EDR Trading North America	NorthWestern Montana	Bonneville Power Administration	SFP	FERC Trf No. 8		
25	EDR Trading North America	NorthWestern Montana	PacifiCorp	NF	FERC Trf No. 8		
26	EDR Trading North America	Puget Sound Energy	NorthWestern Montana	SFP	FERC Trf No. 8		
27	EPCOR Energy Marketing	NorthWestern Montana	Bonneville Power Administration	NF	FERC Trf No. 8		
28	EPCOR Energy Marketing	NorthWestern Montana	NorthWestern Montana	NF	FERC Trf No. 8		
29	EPCOR Energy Marketing	Idaho Power Company	Bonneville Power Administration	SFP	FERC Trf No. 8		
30	Energy Keepers	Bonneville Power Administration	NorthWestern Montana	NF	FERC Trf No. 8		
31	Energy Keepers	Bonneville Power Administration	NorthWestern Montana	SFP	FERC Trf No. 8		
32	Energy Keepers	NorthWestern Montana	Bonneville Power Administration	NF	FERC Trf No. 8		
33	Energy Keepers	NorthWestern Montana	Bonneville Power Administration	SFP	FERC Trf No. 8		
34	Energy Keepers	NorthWestern Montana	Idaho Power Company	NF	FERC Trf No. 8		
35	Energy Keepers	NorthWestern Montana	PacifiCorp	NF	FERC Trf No. 8		
36	Energy Keepers	Idaho Power Company	Bonneville Power Administration	NF	FERC Trf No. 8		
37	Energy Keepers	Idaho Power Company	NorthWestern Montana	NF	FERC Trf No. 8		
38	Energy Keepers	Idaho Power Company	NorthWestern Montana	SFP	FERC Trf No. 8		
39	Energy Keepers	Idaho Power Company	Avista Corporation	NF	FERC Trf No. 8		
40	Energy Keepers	Idaho Power Company	Avista Corporation	SFP	FERC Trf No. 8		
41	Exelon	NorthWestern Montana	Bonneville Power Administration	NF	FERC Trf No. 8		

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")							
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)
42	Exelon	NorthWestern Montana	Bonneville Power Administration	SFP	FERC Trf No. 8		
43	Grant County PUD	Grant County PUD	Grant County PUD	OLF	RS No. 104	Stratford	Coulee City/Wilson
44	Guzman Energy	Bonneville Power Administration	Idaho Power Company	SFP	FERC Trf No. 8		
45	Guzman Energy	Bonneville Power Administration	NorthWestern Montana	NF	FERC Trf No. 8		
46	Guzman Energy	Bonneville Power Administration	NorthWestern Montana	SFP	FERC Trf No. 8		
47	Guzman Energy	Bonneville Power Administration	Avista Corporation	SFP	FERC Trf No. 8		
48	Guzman Energy	NorthWestern Montana	Bonneville Power Administration	NF	FERC Trf No. 8		
49	Guzman Energy	NorthWestern Montana	Bonneville Power Administration	SFP	FERC Trf No. 8		
50	Guzman Energy	Idaho Power Company	Bonneville Power Administration	NF	FERC Trf No. 8		
51	Guzman Energy	Idaho Power Company	Bonneville Power Administration	SFP	FERC Trf No. 8		
52	Guzman Energy	Idaho Power Company	NorthWestern Montana	NF	FERC Trf No. 8		
53	Guzman Energy	Idaho Power Company	NorthWestern Montana	SFP	FERC Trf No. 8		
54	Guzman Energy	Idaho Power Company	Avista Corporation	SFP	FERC Trf No. 8		
55	Hydro Tech Industries	Meyers Falls	Avista Corporation	OLF	PURPA		
56	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	LFP	FERC Trf No. 8	MIDC	LOLO
57	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	LFP	FERC Trf No. 8	AVA.BPAT	LOLO
58	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	NF	FERC Trf No. 8		
59	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	SFP	FERC Trf No. 8		
60	Idaho Power Company	Bonneville Power Administration	NorthWestern Montana	SFP	FERC Trf No. 8		
61	Idaho Power Company	Grant County PUD	Idaho Power Company	SFP	FERC Trf No. 8		
62	Idaho Power Company	Idaho Power Company	NorthWestern Montana	NF	FERC Trf No. 8		

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

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)
63	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	LFP	FERC Trf No. 8		
64	Idaho Power Company	Idaho Power Company	Bonneville Power Administration	NF	FERC Trf No. 8		
65	Kootenai Electric	Avista Corporation	Idaho Power Company	LFP	FERC Trf No. 8	AVA.SYS	LOLO
66	MAG Energy Solutions	Idaho Power Company	Bonneville Power Administration	NF	FERC Trf No. 8		
67	Macquarie Energy	Bonneville Power Administration	NorthWestern Montana	NF	FERC Trf No. 8		
68	Macquarie Energy	Bonneville Power Administration	NorthWestern Montana	SFP	FERC Trf No. 8		
69	Macquarie Energy	Bonneville Power Administration	Avista Corporation	NF	FERC Trf No. 8		
70	Macquarie Energy	NorthWestern Montana	Bonneville Power Administration	NF	FERC Trf No. 8		
71	Macquarie Energy	NorthWestern Montana	Bonneville Power Administration	SFP	FERC Trf No. 8		
72	Macquarie Energy	NorthWestern Montana	Idaho Power Company	SFP	FERC Trf No. 8		
73	Macquarie Energy	Idaho Power Company	Bonneville Power Administration	NF	FERC Trf No. 8		
74	Macquarie Energy	Idaho Power Company	Bonneville Power Administration	SFP	FERC Trf No. 8		
75	Macquarie Energy	Idaho Power Company	NorthWestern Montana	NF	FERC Trf No. 8		
76	Macquarie Energy	Idaho Power Company	NorthWestern Montana	SFP	FERC Trf No. 8		
77	Macquarie Energy	Idaho Power Company	Avista Corporation	SFP	FERC Trf No. 8		
78	Mercuria Energy America	Bonneville Power Administration	NorthWestern Montana	NF	FERC Trf No. 8		
79	Morgan Stanley Capital Group	Bonneville Power Administration	Idaho Power Company	NF	FERC Trf No. 8		
80	Morgan Stanley Capital Group	Bonneville Power Administration	Idaho Power Company	SFP	FERC Trf No. 8		
81	Morgan Stanley Capital Group	Bonneville Power Administration	NorthWestern Montana	NF	FERC Trf No. 8		
82	Morgan Stanley Capital Group	NorthWestern Montana	Bonneville Power Administration	NF	FERC Trf No. 8		
83	Morgan Stanley Capital Group	NorthWestern Montana	Bonneville Power Administration	SFP	FERC Trf No. 8		

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")							
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)
84	Morgan Stanley Capital Group	NorthWestern Montana	Idaho Power Company	NF	FERC Trf No. 8		
85	Morgan Stanley Capital Group	NorthWestern Montana	Idaho Power Company	SFP	FERC Trf No. 8		
86	Morgan Stanley Capital Group	NorthWestern Montana	Grant County PUD	NF	FERC Trf No. 8		
87	Morgan Stanley Capital Group	NorthWestern Montana	Grant County PUD	SFP	FERC Trf No. 8		
88	Morgan Stanley Capital Group	Grant County PUD	Idaho Power Company	NF	FERC Trf No. 8		
89	Morgan Stanley Capital Group	Grant County PUD	Idaho Power Company	SFP	FERC Trf No. 8		
90	Morgan Stanley Capital Group	Grant County PUD	NorthWestern Montana	NF	FERC Trf No. 8		
91	Morgan Stanley Capital Group	Grant County PUD	NorthWestern Montana	SFP	FERC Trf No. 8		
92	Morgan Stanley Capital Group	Idaho Power Company	Bonneville Power Administration	NF	FERC Trf No. 8		
93	Morgan Stanley Capital Group	Idaho Power Company	Bonneville Power Administration	SFP	FERC Trf No. 8		
94	Morgan Stanley Capital Group	Idaho Power Company	NorthWestern Montana	NF	FERC Trf No. 8		
95	Morgan Stanley Capital Group	Idaho Power Company	NorthWestern Montana	SFP	FERC Trf No. 8		
96	Morgan Stanley Capital Group	Idaho Power Company	Grant County PUD	NF	FERC Trf No. 8		
97	Morgan Stanley Capital Group	Idaho Power Company	Grant County PUD	SFP	FERC Trf No. 8		
98	NorthWestern Energy	Bonneville Power Administration	NorthWestern Montana	NF	FERC Trf No. 8		
99	NorthWestern Energy	NorthWestern Montana	Bonneville Power Administration	NF	FERC Trf No. 8		
100	NorthWestern Energy	Idaho Power Company	NorthWestern Montana	NF	FERC Trf No. 8		
101	NorthWestern Energy	Avista Corporation	NorthWestern Montana	NF	FERC Trf No. 8		
102	Phillips 66 Energy Trading	Bonneville Power Administration	Idaho Power Company	SFP	FERC Trf No. 8		
103	Phillips 66 Energy Trading	Bonneville Power Administration	NorthWestern Montana	LFP	FERC Trf No. 8		
104	Phillips 66 Energy Trading	Bonneville Power Administration	NorthWestern Montana	SFP	FERC Trf No. 8		

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")							
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)
105	Phillips 66 Energy Trading	NorthWestern Montana	PacifiCorp	NF	FERC Trf No. 8		
106	Phillips 66 Energy Trading	NorthWestern Montana	PacifiCorp	SFP	FERC Trf No. 8		
107	Phillips 66 Energy Trading	Idaho Power Company	Bonneville Power Administration	LFP	FERC Trf No. 8		
108	Phillips 66 Energy Trading	Idaho Power Company	Bonneville Power Administration	SFP	FERC Trf No. 8		
109	Phillips 66 Energy Trading	Idaho Power Company	NorthWestern Montana	LFP	FERC Trf No. 8		
110	Phillips 66 Energy Trading	Idaho Power Company	NorthWestern Montana	NF	FERC Trf No. 8		
111	Phillips 66 Energy Trading	Idaho Power Company	NorthWestern Montana	SFP	FERC Trf No. 8		
112	Phillips 66 Energy Trading	Idaho Power Company	Grant County PUD	NF	FERC Trf No. 8		
113	Phillips 66 Energy Trading	Idaho Power Company	PacifiCorp	LFP	FERC Trf No. 8		
114	Phillips 66 Energy Trading	Idaho Power Company	PacifiCorp	NF	FERC Trf No. 8		
115	Phillips 66 Energy Trading	Idaho Power Company	PacifiCorp	SFP	FERC Trf No. 8		
116	PacifiCorp	Bonneville Power Administration	PacifiCorp	NF	FERC Trf No. 8		
117	PacifiCorp	PacifiCorp	Bonneville Power Administration	NF	FERC Trf No. 8		
118	PacifiCorp	PacifiCorp	PacifiCorp	OLF	RS No. 182	Dry Gulch	Dry Gulch
119	PacifiCorp	Idaho Power Company	Bonneville Power Administration	SFP	FERC Trf No. 8		
120	PacifiCorp	Idaho Power Company	PacifiCorp	NF	FERC Trf No. 8		
121	PacifiCorp	Idaho Power Company	PacifiCorp	SFP	FERC Trf No. 8		
122	Portland General Electric	Bonneville Power Administration	Idaho Power Company	NF	FERC Trf No. 8		
123	Portland General Electric	Bonneville Power Administration	NorthWestern Montana	SFP	FERC Trf No. 8		
124	Portland General Electric	NorthWestern Montana	Bonneville Power Administration	NF	FERC Trf No. 8		
125	Portland General Electric	NorthWestern Montana	Portland General Electric	NF	FERC Trf No. 8		

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

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)
126	Portland General Electric	Idaho Power Company	Bonneville Power Administration	NF	FERC Trf No. 8		
127	Avangrid Renewables	Bonneville Power Administration	Idaho Power Company	NF	FERC Trf No. 8		
128	Avangrid Renewables	Bonneville Power Administration	NorthWestern Montana	NF	FERC Trf No. 8		
129	Avangrid Renewables	NorthWestern Montana	Bonneville Power Administration	NF	FERC Trf No. 8		
130	Avangrid Renewables	Idaho Power Company	Bonneville Power Administration	NF	FERC Trf No. 8		
131	Puget Sound Energy	NorthWestern Montana	Bonneville Power Administration	NF	FERC Trf No. 8		
132	Puget Sound Energy	NorthWestern Montana	Bonneville Power Administration	SFP	FERC Trf No. 8		
133	Puget Sound Energy	NorthWestern Montana	Puget Sound Energy	NF	FERC Trf No. 8		
134	Puget Sound Energy	NorthWestern Montana	Puget Sound Energy	SFP	FERC Trf No. 8		
135	Puget Sound Energy	Idaho Power Company	Bonneville Power Administration	NF	FERC Trf No. 8		
136	Powerex	Bonneville Power Administration	Idaho Power Company	LFP	FERC Trf No. 8	AVA.BPAT	LOLO
137	Powerex	Bonneville Power Administration	Idaho Power Company	NF	FERC Trf No. 8		
138	Powerex	Bonneville Power Administration	Idaho Power Company	SFP	FERC Trf No. 8		
139	Powerex	Bonneville Power Administration	NorthWestern Montana	LFP	FERC Trf No. 8		
140	Powerex	Bonneville Power Administration	NorthWestern Montana	NF	FERC Trf No. 8		
141	Powerex	Bonneville Power Administration	NorthWestern Montana	SFP	FERC Trf No. 8		
142	Powerex	Bonneville Power Administration	PacifiCorp	NF	FERC Trf No. 8		
143	Powerex	Bonneville Power Administration	PacifiCorp	SFP	FERC Trf No. 8		
144	Powerex	NorthWestern Montana	Bonneville Power Administration	LFP	FERC Trf No. 8		
145	Powerex	NorthWestern Montana	Bonneville Power Administration	NF	FERC Trf No. 8		
146	Powerex	NorthWestern Montana	Bonneville Power Administration	SFP	FERC Trf No. 8		

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

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)
147	Powerex	Idaho Power Company	Bonneville Power Administration	LFP	FERC Trf No. 8		
148	Powerex	Idaho Power Company	Bonneville Power Administration	NF	FERC Trf No. 8		
149	Powerex	Idaho Power Company	Bonneville Power Administration	SFP	FERC Trf No. 8		
150	Powerex	Idaho Power Company	NorthWestern Montana	LFP	FERC Trf No. 8		
151	Rainbow Energy Marketing Corporation	Bonneville Power Administration	Idaho Power Company	NF	FERC Trf No. 8		
152	Rainbow Energy Marketing Corporation	Bonneville Power Administration	NorthWestern Montana	NF	FERC Trf No. 8		
153	Rainbow Energy Marketing Corporation	NorthWestern Montana	Bonneville Power Administration	LFP	FERC Trf No. 8		
154	Rainbow Energy Marketing Corporation	NorthWestern Montana	Bonneville Power Administration	NF	FERC Trf No. 8		
155	Rainbow Energy Marketing Corporation	NorthWestern Montana	Bonneville Power Administration	SFP	FERC Trf No. 8		
156	Rainbow Energy Marketing Corporation	NorthWestern Montana	Chelan County PUD	SFP	FERC Trf No. 8		
157	Rainbow Energy Marketing Corporation	NorthWestern Montana	Grant County PUD	SFP	FERC Trf No. 8		
158	Rainbow Energy Marketing Corporation	NorthWestern Montana	PacifiCorp	SFP	FERC Trf No. 8		
159	Rainbow Energy Marketing Corporation	NorthWestern Montana	Portland General Electric	SFP	FERC Trf No. 8		
160	Rainbow Energy Marketing Corporation	Idaho Power Company	Bonneville Power Administration	NF	FERC Trf No. 8		
161	Rainbow Energy Marketing Corporation	Idaho Power Company	Bonneville Power Administration	SFP	FERC Trf No. 8		
162	Rainbow Energy Marketing Corporation	Idaho Power Company	PacifiCorp	SFP	FERC Trf No. 8		
163	Seattle City Light	Seattle City Light	Grant County PUD	OLF	FERC Trf No. 8	Chelan-Stratford	Stratford
164	Seattle City Light	NorthWestern Montana	Bonneville Power Administration	NF	FERC Trf No. 8		
165	Spokane Tribe	Bonneville Power Administration	Spokane Tribe	LFP	FERC Trf No. 8	AVA.BPAT	AVA.SYS
166	Stimson	Plummer	Avista Corporation	OLF	PURPA		
167	The Energy Authority	Bonneville Power Administration	Idaho Power Company	NF	FERC Trf No. 8		

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")							
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)
168	The Energy Authority	Bonneville Power Administration	Idaho Power Company	SFP	FERC Trf No. 8		
169	The Energy Authority	Bonneville Power Administration	NorthWestern Montana	NF	FERC Trf No. 8		
170	The Energy Authority	Bonneville Power Administration	Avista Corporation	NF	FERC Trf No. 8		
171	The Energy Authority	NorthWestern Montana	Bonneville Power Administration	NF	FERC Trf No. 8		
172	The Energy Authority	NorthWestern Montana	PacifiCorp	NF	FERC Trf No. 8		
173	The Energy Authority	Idaho Power Company	Bonneville Power Administration	NF	FERC Trf No. 8		
174	The Energy Authority	Idaho Power Company	Bonneville Power Administration	SFP	FERC Trf No. 8		
175	TransAlta Energy Marketing	Bonneville Power Administration	Idaho Power Company	NF	FERC Trf No. 8		
176	TransAlta Energy Marketing	Bonneville Power Administration	NorthWestern Montana	NF	FERC Trf No. 8		
177	TransAlta Energy Marketing	NorthWestern Montana	Bonneville Power Administration	NF	FERC Trf No. 8		
178	TransAlta Energy Marketing	NorthWestern Montana	Idaho Power Company	NF	FERC Trf No. 8		
179	TransAlta Energy Marketing	Puget Sound Energy	NorthWestern Montana	NF	FERC Trf No. 8		
180	TransAlta Energy Marketing	Idaho Power Company	Bonneville Power Administration	NF	FERC Trf No. 8		
181	TransAlta Energy Marketing	Idaho Power Company	NorthWestern Montana	NF	FERC Trf No. 8		
182	TransAlta Energy Marketing	Idaho Power Company	Avista Corporation	NF	FERC Trf No. 8		
183	Tenaska Power Services	NorthWestern Montana	Idaho Power Company	NF	FERC Trf No. 8		
184	Tacoma Power	Tacoma Power	Grant County PUD	OLF	FERC Trf No. 8	Chelan-Stratford	Stratford
185	East Greenacres	Bonneville Power Administration	East Greenacres	LFP	FERC Trf No. 8	AVA.BPAT	AVA.SYS
35	TOTAL						

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

Line No.	Billing Demand (MW) (h)	TRANSFER OF ENERGY Megawatt Hours Received (i)	TRANSFER OF ENERGY Megawatt Hours Delivered (j)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Demand Charges ($) (k)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Energy Charges ($) (l)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Other Charges ($) (m)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Total Revenues ($) (k+l+m) (n)
1		2,204,529	2,204,529	9,755,950		[(a)]1,127,795	10,883,745
2						[(b)]924,000	924,000
3		11,460	11,460	99,165			99,165
4				119			119
5						[(c)]27,973	27,973
6	4	6,924	6,924	32,980		[(d)]10,021	43,001
7		33	33	325			325
8		350	350	2,977			2,977
9		401	401	4,011			4,011
10		1,526	1,526	17,647			17,647
11		263	263	3,017			3,017
12		604	604	6,217			6,217
13		424	424	4,972			4,972
14						[(e)]603	603
15		200	200	1,903			1,903
16		994	994	10,275			10,275
17		110	110	1,660			1,660
18		50	50	397			397
19		489	489	5,067			5,067
20		3,334	3,334	29,037			29,037
21		1,513	1,513	12,029			12,029
22		624	624	3,297			3,297
23		6,924	6,924	57,287			57,287
24		960	960	5,072			5,072
25		80	80	666			666
26		504	504	2,663			2,663
27		60	60	476			476
28				3			3
29		400	400	3,170			3,170
30		1,444	1,444	11,803			11,803

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

Line No.	Billing Demand (MW) (h)	TRANSFER OF ENERGY Megawatt Hours Received (i)	TRANSFER OF ENERGY Megawatt Hours Delivered (j)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Demand Charges ($) (k)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Energy Charges ($) (l)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Other Charges ($) (m)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Total Revenues ($) (k+l+m) (n)
31		400	400	3,170			3,170
32		2,446	2,446	20,745			20,745
33		21,334	21,334	127,554			127,554
34		302	302	2,404			2,404
35		400	400	3,208			3,208
36		122	122	1,209			1,209
37		475	475	4,708			4,708
38		545	545	2,988			2,988
39		275	275	2,726			2,726
40		4,775	4,775	25,808			25,808
41		1,200	1,200	9,516			9,516
42		1,200	1,200	6,340			6,340
43		92,191	92,191	26,793			26,793
44		32	32	375			375
45		1,525	1,525	14,643			14,643
46		9,595	9,595	112,188			112,188
47		25	25	293			293
48		2,132	2,132	52,357			52,357
49		132,579	132,579	669,304			669,304
50		10,712	10,712	96,453			96,453
51		60,571	60,571	322,295			322,295
52		100	100	949			949
53		359	359	2,415			2,415
54		319	319	1,438			1,438
55						(f)5,772	5,772
56	100	232,681	232,681	3,298,000			3,298,000
57	100	93,599	93,599	3,294,400			3,294,400
58		528	528	4,187			4,187
59		4,600	4,600	17,735			17,735
60		2,400	2,400	104,383			104,383

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")							
Line No.	Billing Demand (MW) (h)	TRANSFER OF ENERGY Megawatt Hours Received (i)	TRANSFER OF ENERGY Megawatt Hours Delivered (j)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Demand Charges ($) (k)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Energy Charges ($) (l)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Other Charges ($) (m)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Total Revenues ($) (k+l+m) (n)
61		400	400	1,542			1,542
62		111	111	1,118			1,118
63		3,000	3,000	(40,200)			(40,200)
64		75	75	595			595
65	3	16,269	16,269	98,940		(g)22,549	121,489
66				8			8
67		564	564	4,869			4,869
68		676	676	6,555			6,555
69		6	6	60			60
70		4,069	4,069	57,131			57,131
71		36,588	36,588	338,379			338,379
72		766	766	6,864			6,864
73		697	697	9,516			9,516
74		3,559	3,559	82,594			82,594
75		342	342	5,337			5,337
76		1,128	1,128	17,815			17,815
77		272	272	7,238			7,238
78		8,319	8,319	66,641			66,641
79		814	814	8,996			8,996
80		1,000	1,000	6,343			6,343
81		9,086	9,086	82,770			82,770
82		35,240	35,240	355,397			355,397
83		34,513	34,513	246,302			246,302
84		3,748	3,748	37,681			37,681
85		8,484	8,484	61,848			61,848
86		8,514	8,514	86,169			86,169
87		23,538	23,538	161,303			161,303
88		1,456	1,456	14,456			14,456
89		6,516	6,516	53,581			53,581

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")							
		TRANSFER OF ENERGY	TRANSFER OF ENERGY	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS
Line No.	Billing Demand (MW) (h)	Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
90		7,817	7,817	74,310			74,310
91		1,372	1,372	10,252			10,252
92		3,820	3,820	41,351			41,351
93		24,884	24,884	146,097			146,097
94		1,987	1,987	19,688			19,688
95		2,830	2,830	17,619			17,619
96		1,861	1,861	17,377			17,377
97		1,206	1,206	8,511			8,511
98		1,332	1,332	10,964			10,964
99		110	110	3,251			3,251
100		34	34	270			270
101				198			198
102		1,200	1,200	6,714			6,714
103		6,556	6,556	4,997			4,997
104		2,200	2,200	12,310			12,310
105		400	400	3,281			3,281
106		2,302	2,302	10,586			10,586
107		6,556	6,556	1,904			1,904
108		1,000	1,000	3,600			3,600
109		7,996	7,996	16,051			16,051
110		749	749	6,021			6,021
111		15,610	15,610	86,106			86,106
112		250	250	1,983			1,983
113		6,556	6,556	13,649			13,649
114		400	400	3,172			3,172
115		87,738	87,738	460,330			460,330
116		5,137	5,137	64,591			64,591
117		20,221	20,221	270,481			270,481
118		40,399	40,399	193,137			193,137
119				6,340			6,340

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

Line No.	Billing Demand (MW) (h)	TRANSFER OF ENERGY Megawatt Hours Received (i)	TRANSFER OF ENERGY Megawatt Hours Delivered (j)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Demand Charges ($) (k)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Energy Charges ($) (l)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Other Charges ($) (m)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Total Revenues ($) (k+l+m) (n)
120		67	67	593			593
121		34,985	34,985	212,010			212,010
122		18	18	206			206
123		13	13	49,326			49,326
124		17,978	17,978	167,468			167,468
125		448	448	4,899			4,899
126		3,396	3,396	35,653			35,653
127		101	101	1,225			1,225
128		30	30	238			238
129		5,261	5,261	44,424			44,424
130		100	100	821			821
131		2,368	2,368	25,408			25,408
132		2,883	2,883	15,688			15,688
133		6,711	6,711	61,141			61,141
134		109,868	109,868	625,413			625,413
135		1,820	1,820	16,081			16,081
136	137	423,850	423,850	3,533,603			3,533,603
137		1,281	1,281	11,830			11,830
138		64,007	64,007	78,992			78,992
139		60	60	910			910
140		4,881	4,881	41,528			41,528
141		722	722	29,153			29,153
142		68	68	624			624
143		3,736	3,736	52,910			52,910
144		38,209	38,209	414,480			414,480
145		1,787	1,787	15,734			15,734
146		1,008	1,008	18,589			18,589
147		41,672	41,672	553,986			553,986
148		5,991	5,991	51,478			51,478
149		5,213	5,213	141,132			141,132

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

Line No.	Billing Demand (MW) (h)	TRANSFER OF ENERGY Megawatt Hours Received (i)	TRANSFER OF ENERGY Megawatt Hours Delivered (j)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Demand Charges ($) (k)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Energy Charges ($) (l)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Other Charges ($) (m)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Total Revenues ($) (k+l+m) (n)
150		1,008	1,008	15,282			15,282
151		108	108	1,091			1,091
152		282	282	2,508			2,508
153		267	267	3,600			3,600
154		1,441	1,441	12,506			12,506
155		267	267	2,417			2,417
156		200	200	1,280			1,280
157		125	125	800			800
158		400	400	2,559			2,559
159		266	266	1,702			1,702
160		3,788	3,788	35,385			35,385
161		5,497	5,497	45,214			45,214
162		1,560	1,560	14,121			14,121
163		122,807	122,807	203,814		(h) 90,228	294,042
164		295	295	2,339			2,339
165	3	3,038	3,038	24,735		(i) 6,362	31,097
166						(j) 8,448	8,448
167		621	621	14,827			14,827
168		50	50	482			482
169		64	64	1,221			1,221
170		5	5	103			103
171		2,093	2,093	19,214			19,214
172		289	289	2,774			2,774
173		2,399	2,399	22,025			22,025
174		3,359	3,359	31,862			31,862
175		82	82	1,021			1,021
176		440	440	6,460			6,460
177		3,954	3,954	37,721			37,721
178		20	20	161			161
179		106	106	1,320			1,320

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")							
		TRANSFER OF ENERGY	TRANSFER OF ENERGY	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS
Line No.	Billing Demand (MW) (h)	Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
180		1,688	1,688	19,023			19,023
181		34	34	369			369
182		266	266	2,884			2,884
183		609	609	5,710			5,710
184		122,793	122,793	296,820		(k)90,228	387,048
185	3	3,705	3,705	14,841		(l)6,510	21,351
35	350	4,446,353	4,446,353	28,649,492	0	2,320,489	30,969,981

FOOTNOTE DATA

(a) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Ancillary services
(b) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Parallel Capacity Support agreement
(c) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Use of facilities
(d) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Ancillary services
(e) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Use of facilities
(f) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Use of facilities
(g) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Ancillary services
(h) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Use of facilities
(i) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Ancillary services
(j) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Use of facilities
(k) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Use of facilities
(l) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Ancillary services

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY MegaWatt Hours Received (c)	TRANSFER OF ENERGY MegaWatt Hours Delivered (d)
1	Bonneville Power Admin	LFP		
2	Bonneville Power Admin	LFP		
3	Bonneville Power Admin	OS		
4	Bonneville Power Admin	FNS		
5	Bonneville Power Admin	NF	79,027	79,027
6	Benton County PUD No 1	NF	100	100
7	Energy Keepers, Inc.	NF	19,152	19,152
8	Grays Harbor County PUD No 1	NF	100	100
9	Idaho Power Company	NF	3,002	3,002
10	Kootenai Electric Coop	LFP		
11	Nevada Power Company	NF	50	50
12	Northern Lights, Inc	LFP		
13	NorthWestern Energy	NF	33,498	33,498
14	NorthWestern Energy	SFP		
15	PacifiCorp	NF	30	30
16	Portland General Elect	NF	2,457	2,457
17	Portland General Elect	LFP		
18	Puget Sound Energy	NF	10,657	10,657
19	Seattle City Light	NF	11,713	11,713
20	Shell Energy North America	NF	55	55
21	Snohomish County PUD	NF	44,599	44,599
22	The Energy Authority	NF	675	675
	TOTAL		205,115	205,115

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

Line No.	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Energy Charges ($) (f)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Other Charges ($) (g)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Total Cost of Transmission ($) (h)
1	1,445,942			1,445,942
2	12,069,727		[(a)]2,311,100	14,380,827
3			[(b)]54,432	54,432
4	1,453,332		[(c)]297,670	1,751,002
5		440,023		440,023
6		125		125
7		82,896		82,896
8		125		125
9		12,920		12,920
10	51,525			51,525
11		303		303
12	152,439			152,439
13		174,757		174,757
14	656,735		[(d)]26,994	683,729
15		141		141
16		3,265		3,265
17	1,195,044		[(e)](1,470,237)	(275,193)
18		25,479	[(f)]1,711	27,190
19		20,400		20,400
20		83		83
21		55,749		55,749
22		756		756
	17,024,744	817,022	1,221,670	19,063,436

FOOTNOTE DATA

(a) Concept: OtherChargesTransmissionOfElectricityByOthers
Ancillary Services
(b) Concept: OtherChargesTransmissionOfElectricityByOthers
Use of Facilities
(c) Concept: OtherChargesTransmissionOfElectricityByOthers
Ancillary Services
(d) Concept: OtherChargesTransmissionOfElectricityByOthers
Ancillary Services and Regulation & Frequency Response
(e) Concept: OtherChargesTransmissionOfElectricityByOthers
Ancillary Services of $75,713, and Redirect Credit of ($1,545,950) equals ($1,470,237)
(f) Concept: OtherChargesTransmissionOfElectricityByOthers
Schedule 11 WA Tax Rider

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	925,831
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	688,834
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Community Relations	633,259
7	Compliance	60,097
8	Board of Director Activities	1,758,100
9	Education, Information, & Training	705,943
10	Emergency Operating Procedure Events	6,931
11	Misc Employee Expenses	115,331
12	Misc Legal, Professional & General Services	184,897
13	Misc Transportation	214,058
14	Other Misc Expenses <$5,000	10,107
15	Misc. Labor	341,477
46	TOTAL	5,644,865

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

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

Line No.	A. Summary of Depreciation and Amortization Charges Functional Classification (a)	A. Summary of Depreciation and Amortization Charges Depreciation Expense (Account 403) (b)	A. Summary of Depreciation and Amortization Charges Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	A. Summary of Depreciation and Amortization Charges Amortization of Limited Term Electric Plant (Account 404) (d)	A. Summary of Depreciation and Amortization Charges Amortization of Other Electric Plant (Acc 405) (e)	A. Summary of Depreciation and Amortization Charges Total (f)
1	Intangible Plant			9,850,589		9,850,589
2	Steam Production Plant	17,056,563				17,056,563
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	16,632,247				16,632,247
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	11,041,726				11,041,726
7	Transmission Plant	21,064,671				21,064,671
8	Distribution Plant	60,509,580				60,509,580
9	Regional Transmission and Market Operation					
10	General Plant	4,750,023		422,432		5,172,455
11	Common Plant-Electric	18,217,879		36,465,620		54,683,499
12	TOTAL	149,272,689		46,738,641		196,011,330

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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	STEAM PLANT						
13	Colstrip No. 3						
14	311	57.697	70 years	(6)%	1.99%	S1.5	8 years
15	312	86.809	60 years	(6)%	2.67%	R1	8 years
16	313	0.106		(6)%	9.22%	R2.5	8 years
17	314	23.214	40 years	(6)%	8.34%	R0.5	8 years
18	315	10.794	50 years	(6)%	2.97%	R3	8 years
19	316	10.254	53 years	(6)%	3.9574%	R2	8 years

20	Subtotal	188.874					
21	Colstrip No. 4						
22	311	54.164	70 years	(7)%	2.95%	S1.5	8 years
23	312	60.035	60 years	(7)%	4.79%	R1	8 years
24	313	0.126		(7)%	9.34%	R2.5	8 years
25	314	16.53	40 years	(7)%	7.59%	R0.5	8 years
26	315	7.548	50 years	(7)%	3.72%	R3	8 years
27	316	4.637	53 years	(7)%	4.74%	R2	8 years
28	Subtotal	143.041					
29	Kettle Falls						
30	310	0.427			1.32%	SQ	12 years
31	311	29.62	70 years	(4)%	2.49%	S1.5	12 years
32	312	79.695	55 years	(4)%	3.18%	R1	11 years
33	314	18.703	35 years	(4)%	2.25%	R0.5	10 years
34	315	12.605	50 years	(4)%	4.06%	R3	11 years
35	316	2.477	55 years	(4)%	2.97%	R2	11 years
36	Subtotal	143.527					
37	HYDRO PLANT						
38	Cabinet Gorge						
39	330	9.383	100 years		1.9%	R4	38 years
40	331	27.321	55 years	(16)%	1.7275%	R2	42 years
41	332	112.278	60 years	(16)%	2.0275%	R1	43 years
42	333	47.871	65 years	(16)%	2.59%	R1.5	41 years
43	334	20.114	40 years	(16)%	2.1%	S1	29 years
44	335	6.452	50 years	(16)%	1.8925%	R1	41 years
45	336	1.865	55 years	(16)%	2%	S2.5	29 years
46	Subtotal	225.284					
47	Noxon Rapids						
48	330	30.747	100 years		1.64%	R4	53 years
49	331	25.083	55 years	(24)%	2.2325%	R2	45 years
50	332	41.685	60 years	(24)%	2.2225%	R1	47 years
51	333	89.308	65 years	(24)%	2.41%	R1.5	45 years
52	334	20.622	40 years	(24)%	4.09%	S1	27 years
53	335	4.57	50 years	(24)%	2.0375%	R1	42 years
54	336	0.306	55 years	(24)%	2.96%	S2.5	26 years
55	Subtotal	212.32					
56	Post Falls						

57	330	2.908	80 years		1.905%	R4	24 years
58	331	8.103	55 years	(4)%	1.53%	R2	38 years
59	332	26.064	60 years	(4)%	2.48%	R1	37 years
60	333	2.234	65 years	(4)%	0.79%	R1.5	34 years
61	334	2.304	40 years	(4)%	1.2%	S1	23 years
62	335	1.047	60 years	(4)%	2.39%	R1	37 years
63	336	0.578	55 years	(4)%	2.62%	S2.5	26 years
64	Subtotal	43.237					
65	Long Lake						
66	330	0.418	80 years		1.91%	R4	26 years
67	331	11.286	55 years	(7)%	1.64%	R2	34 years
68	332	39.074	60 years	(7)%	1.85%	R1	34 years
69	333	8.897	65 years	(7)%	0.45%	R1.5	34 years
70	334	4.59	40 years	(7)%	0.85%	S1	29 years
71	335	0.881	60 years	(7)%	1.69%	R1	33 years
72	336	0	55 years	(7)%	2.62%	S2.5	26 years
73	Subtotal	65.146					
74	Little Falls						
75	330	4.217	80 years		1.28%	R4	20 years
76	331	5.533	110 years	(7)%	1.87%	R2	42 years
77	332	6.408	110 years	(7)%	1.17%	R1	40 years
78	333	39.332	65 years	(7)%	1.4%	R1.5	39 years
79	334	13.959	40 years	(7)%	2.72%	S1	32 years
80	335	0.549	60 years	(7)%	1.674%	R1	36 years
81	Subtotal	69.998					
82	Upper Falls						
83	330	0.064	100 years		1.38%	R4	19 years
84	331	4.96	50 years	(7)%	3.36%	R2	31 years
85	332	10.046	110 years	(7)%	1.82%	R1	41 years
86	333	0.768	65 years	(7)%	0.22%	R1.5	38 years
87	334	4.568	40 years	(7)%	3.11%	S1	30 years
88	335	0.113	60 years	(7)%	2.14%	R1	35 years
89	336	0.508	55 years	(7)%	2.53%	S2.5	26 years
90	Subtotal	21.027					
91	Nine Mile						
92	330	0.011	100 years		1.495%	R4	25 years
93	331	24.157	110 years	(4)%	2.41%	R2	40 years

94	332	30.934	110 years	(4)%	2.095%	R1	37 years
95	333	41.143	65 years	(4)%	2.58%	R1.5	39 years
96	334	18.732	40 years	(4)%	2.92%	S1	33 years
97	335	1.041	60 years	(4)%	2.68%	R1	38 years
98	336	0.595	55 years	(4)%	2.7%	S2.5	26 years
99	Subtotal	116.612					
100	Monroe Street						
101	331	12.262	55 years	(7)%	2.39%	R2	41 years
102	332	10.009	110 years	(7)%	1.91%	R1	50 years
103	333	11.68	65 years	(7)%	2.22%	R1.5	41 years
104	334	3.568	40 years	(7)%	3.66%	S1	26 years
105	335	0.034	60 years	(7)%	2.3%	R1	41 years
106	336	0.05	55 years	(7)%	2.89%	R2.5	31 years
107	Subtotal	37.603					
108	OTHER PRODUCTION						
109	Northeast Turbine						
110	341	0.746	55 years	(5)%	30.78%	S4	2 years
111	342	0.037	55 years	(5)%	0%	R3	0 years
112	343	9.058	60 years	(5)%	2.51%	S2.5	2 years
113	344	2.857	45 years	(5)%	2.56%	R1	2 years
114	345	1.249	20 years	(5)%	16.94%	S1	2 years
115	346	0.399	35 years	(5)%	23.28%	R2.5	2 years
116	Subtotal	14.346					
117	Rathdrum Turbine						
118	341	3.74	55 years	(4)%	3.7%	S4	16 years
119	342	1.696	55 years	(4)%	3.56%	R3	18 years
120	343	3.652	60 years	(4)%	3.77%	S2.5	18 years
121	344	51.225	45 years	(4)%	3.94%	R1	16 years
122	345	4.845	20 years	(4)%	8.22%	S1	12 years
123	346	0.249	35 years	(4)%	5.69%	R2.5	17 years
124	Subtotal	65.407					
125	Kettle Falls CT						
126	341	0.013	55 years	(1)%	1.36%	S4	11 years
127	342	0.089	55 years	(1)%	3.33%	R3	12 years
128	343	8.67	60 years	(1)%	3.45%	S2.5	12 years

129	344	0.234	45 years	(1)%	4.11%	R1	11 years
130	345	0.539	20 years	(1)%	8%	S1	11 years
131	Subtotal	9.545					
132	Boulder Park						
133	341	1.312	55 years	(2)%	2.56%	S4	26 years
134	342	0.162	55 years	(2)%	2.62%	R3	25 years
135	343	0.049	60 years	(2)%	2.38%	S2.5	25 years
136	344	31.538	45 years	(2)%	2.43%	R1	22 years
137	345	0.961	20 years	(2)%	6.42%	S1	15 years
138	346	0.065	35 years	(2)%	3.99%	R2.5	24 years
139	Subtotal	34.088					
140	Coyote Springs 2						
141	341	11.801	55 years	(3)%	2.37%	S4	27 years
142	342	19.002	55 years	(3)%	2.45%	R3	26 years
143	344	154.187	45 years	(3)%	3.36%	R1	23 years
144	345	18.7	20 years	(3)%	5.25%	S1	12 years
145	346	0.92	35 years	(3)%	4.268%	R2.5	22 years
146	Subtotal	204.609					
147	Solar Power						
148	344	0.449	25 years	(3)%	7.455%	S2.5	13 years
149	345	0.033					
150	Subtotal	0.482					
151	Lancaster						
152	342	0.092	55 years	(5)%	3.07%	R3	23 years
153	344	0.209	45 years	(5)%	3.52%	R1	22 years
154	345	0.308	20 years	(5)%	6.19%	S1	17 years
155	Subtotal	0.609					
156	TRANSMISSION PLANT						
157	350	23.374	80 years		1.13%	R4	56 years
158	352	38.466	65 years	(10)%	1.63%	S1.5	53 years
159	353	395.869	44 years	(10)%	2.41%	R2	33 years
160	354	17.139	75 years	(15)%	1.51%	R4	42 years
161	355	385.031	63 years	(30)%	1.93%	R2.5	52 years
162	356	192.195	70 years	(30)%	1.9%	R3	46 years
163	357	3.214	60 years		1.64%	R4	47 years
164	358	6.834	50 years		2.06%	S3	29 years

165	359	2.626	70 years		1.41%	R4	43 years
166	Subtotal	1,064.749					
167	DISTRIBUTION PLANT						
168	360	4.536	75 years		1.34%	R4	69 years
169	361	31.548	60 years	(10)%	1.72%	S1.5	47 years
170	362	174.515	42 years	(10)%	2.68%	R1.5	30 years
171	363	0	15 years		6.8%	L3	14 years
172	364 - WA	388.861	67 years	(60)%	2.47%	R2.5	52 years
173	364 - ID	197.636	65 years	(60)%	2.57%	R2.5	52 years
174	365 - WA	230.652	68 years	(50)%	2.27%	R3	44 years
175	365 - ID	136.566	65 years	(50)%	2.45%	R3.5	44 years
176	366 - WA	117.367	75 years	(30)%	1.56%	R1.5	47 years
177	366 - ID	58.78	60 years	(30)%	2.14%	S2.5	47 years
178	367 - WA	194.46	35 years	(30)%	3.44%	S1.5	25 years
179	367 - ID	98.328	35 years	(20)%	2.99%	S1.5	25 years
180	368	358.439	47 years	(10)%	2.16%	R2	36 years
181	369	226.734	65 years	(40)%	2.1%	R4	50 years
182	370 - AN	0.157	35 years	(2)%	2.89%	S0	0 years
183	370 - ID	24.639	15 years		9.06%	S2.5	8 years
184	370 - WA	62.831	35 years		2.89%	S0	27 years
185	371	11.203	10 years		10.36%	S1	10 years
186	373	49.686	37 years	(20)%	1.87%	R2.5	28 years
187	373.4	19.074	37 years	(20)%	3.04%	R2.5	29 years
188	373.5	15.536	37 years	(20)%	3.17%	R2.5	36 years
189	Subtotal	2,401.551					
190	GENERAL PLANT						
191	390.1	21.103	50 years	(5)%	1.9%	R2.5	42 years
192	391	0.033	15 years		6.67%	SQ	15 years
193	391.1	4.055	5 years		20%	SQ	2 years
194	393	0.473	25 years		4%	SQ	15 years
195	394	9.011	20 years		5%	SQ	11 years
196	395	3.361	15 years		6.67%	SQ	7 years
197	397	43.279	15 years		6.67%	SQ	9 years
198	398	0.259	10 years		10%	SQ	7 years
199	Subtotal	81.574					

200	MISC POWER EQUIPMENT						
201	392	11.413	16 years		5.48%	L2.5	12 years
202	396	3.838	22 years		3.75%	S1	15 years
203	Subtotal	15.251					
204	Total Company	5,158.88					

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

REGULATORY COMMISSION EXPENSES

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 CURRENTLY CHARGED TO Department (f)	EXPENSES INCURRED DURING YEAR CURRENTLY CHARGED TO Account No. (g)
1	Federal Energy Regulatory Commission - Charges include annual fee and license fees for the Spokane River Project, the Cabinet Gorge Project and the Noxon Rapids Project	3,651,398	200,949	3,852,347		Electric	928
2	Washington Utilities and Transportation Commission						
3	Electric - Includes annual fee and various other electric dockets	2,376,954	488,941	2,865,895		Electric	928
4	Gas - Includes annual fee and various other natural gas dockets	887,457	143,367	1,030,824		Gas	928
5	Idaho Public Utilities Commission						
6	Electric - Includes annual fee and various other electric dockets	578,031	312,522	890,553		Electric	928
7	Gas - Includes annual fee and various other natural gas dockets	179,872	71,625	251,497		Gas	928
8	Public Utility Commission of Oregon						
9	Includes annual fees and various other natural gas dockets	903,979	306,869	1,210,848	98,369	Gas	928
10	Not directly assigned Electric		778,751	778,751		Electric	928
11	Not directly assigned Natural Gas		341,241	341,241		Gas	928
46	TOTAL	8,577,691	2,644,265	11,221,956	98,369		

REGULATORY COMMISSION EXPENSES

Line No.	EXPENSES INCURRED DURING YEAR CURRENTLY CHARGED TO Amount (h)	EXPENSES INCURRED DURING YEAR Deferred to Account 182.3 (i)	AMORTIZED DURING YEAR Contra Account (j)	AMORTIZED DURING YEAR Amount (k)	AMORTIZED DURING YEAR Deferred in Account 182.3 End of Year (l)
1	3,852,347				
2					
3	2,865,895	1,264,383	407		1,264,383
4	1,030,824	571,217	407		571,217
5					
6	890,553				
7	251,497				
8					
9	1,210,848	100,648	407	119,201	79,816
10	778,751				
11	341,241				
46	11,221,956	1,936,248		119,201	1,915,416

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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)
1	A. Electric (3) Distribution	Clean Energy and Electric Vehicle Supply Equipment	1,376,226	2,688,686
2	A. Electric (3) Distribution	Clean Energy and Electric Vehicle Supply Equipment	4,390	0
3	A. Electric (3) Distribution	Clean Energy and Electric Vehicle Supply Equipment	14,147	0
4	A. Electric (3) Distribution	Clean Energy and Electric Vehicle Supply Equipment	22,494	(168,454)
5	A. Electric (3) Distribution	Clean Energy and Electric Vehicle Supply Equipment	0	41,162
6	A. Electric (3) Distribution	Clean Energy and Electric Vehicle Supply Equipment	207,393	0
7	A. Electric (3) Distribution	Clean Energy and Electric Vehicle Supply Equipment	0	8,763
8	A. Electric (3) Distribution	Clean Energy and Electric Vehicle Supply Equipment	30,937	43,260
9	A. Electric (3) Distribution	Clean Energy and Electric Vehicle Supply Equipment	17,370	51,294
10	A. Electric (3) Distribution	Clean Energy and Electric Vehicle Supply Equipment	214	43,432
11	A. Electric (3) Distribution	Clean Energy and Electric Vehicle Supply Equipment	37,025	0
12	A. Electric (3) Distribution	Clean Energy and Electric Vehicle Supply Equipment	2,362	3,258
13	A. Electric (6) Other - Testing Lab & Facility	HUB-Morris Center Lab Test Facility	79,505	276,892
14	A. Electric (6) Other - Testing Lab & Facility	HUB-Morris Center Lab Test Facility	1,002	0

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

Line No.	AMOUNTS CHARGED IN CURRENT YEAR Amounts Charged In Current Year: Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amounts Charged In Current Year: Amount (f)	Unamortized Accumulation (g)
1	107	4,064,912	
2	108	4,390	
3	182	14,147	
4	186	(145,960)	
5	557	41,162	
6	580	207,393	
7	587	8,763	
8	598	74,197	
9	909	68,664	
10	912	43,646	
11	920	37,025	
12	930	5,620	
13	107	356,397	
14	182	1,002	

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

DISTRIBUTION OF SALARIES AND WAGES

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	15,180,372		
4	Transmission	5,610,502		
5	Regional Market	0		
6	Distribution	12,299,941		
7	Customer Accounts	6,507,117		
8	Customer Service and Informational	422,600		
9	Sales	0		
10	Administrative and General	29,427,473		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	69,448,005		
12	Maintenance			
13	Production	4,713,472		
14	Transmission	1,001,293		
15	Regional Market	0		
16	Distribution	4,725,477		
17	Administrative and General	0		
18	TOTAL Maintenance (Total of lines 13 thru 17)	10,440,242		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	19,893,844		
21	Transmission (Enter Total of lines 4 and 14)	6,611,795		
22	Regional Market (Enter Total of Lines 5 and 15)	0		
23	Distribution (Enter Total of lines 6 and 16)	17,025,418		
24	Customer Accounts (Transcribe from line 7)	6,507,117		
25	Customer Service and Informational (Transcribe from line 8)	422,600		
26	Sales (Transcribe from line 9)	0		
27	Administrative and General (Enter Total of lines 10 and 17)	29,427,473		

DISTRIBUTION OF SALARIES AND WAGES				
Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	79,888,247	9,629,046	89,517,293
29	Gas			
30	Operation			
31	Production - Manufactured Gas	0		
32	Production-Nat. Gas (Including Expl. And Dev.)	0		
33	Other Gas Supply	1,176,409		
34	Storage, LNG Terminaling and Processing	0		
35	Transmission	0		
36	Distribution	9,858,961		
37	Customer Accounts	3,088,460		
38	Customer Service and Informational	288,019		
39	Sales	0		
40	Administrative and General	11,927,195		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	26,339,044		
42	Maintenance			
43	Production - Manufactured Gas	0		
44	Production-Natural Gas (Including Exploration and Development)	0		
45	Other Gas Supply	0		
46	Storage, LNG Terminaling and Processing	0		
47	Transmission	2,433,655		
48	Distribution	3,689,066		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	6,122,721		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	0		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,	0		
54	Other Gas Supply (Enter Total of lines 33 and 45)	1,176,409		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	0		
56	Transmission (Lines 35 and 47)	2,433,655		

DISTRIBUTION OF SALARIES AND WAGES				
Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
57	Distribution (Lines 36 and 48)	13,548,027		
58	Customer Accounts (Line 37)	3,088,460		
59	Customer Service and Informational (Line 38)	288,019		
60	Sales (Line 39)	0		
61	Administrative and General (Lines 40 and 49)	11,927,195		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	32,461,765	2,737,908	35,199,673
63	Other Utility Departments			
64	Operation and Maintenance			0
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	112,350,012	12,366,954	124,716,966
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	53,228,480	8,231,597	61,460,077
69	Gas Plant	15,228,319	2,355,006	17,583,325
70	Other (provide details in footnote):			0
71	TOTAL Construction (Total of lines 68 thru 70)	68,456,799	10,586,603	79,043,402
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,754,050	219,243	2,973,293
74	Gas Plant	991,983	78,969	1,070,952
75	Other (provide details in footnote):			0
76	TOTAL Plant Removal (Total of lines 73 thru 75)	3,746,033	298,212	4,044,245
77	Other Accounts (Specify, provide details in footnote):			
78	Stores Expense (163)	3,033,814	(3,033,814)	0
79	Preliminary Survey and Investigation (183)	0	0	0
80	Small Tool Expense (184)	5,526,184	(5,526,184)	0
81	Miscellaneous Deferred Debits (186)	1,274,251		1,274,251
82	Non-operating Expenses (417)	743,935		743,935
83	Retirement Bonus/SERP/HRA (228)	39,474		39,474
84	Other Income Deductions (426)	974,987		974,987
85	Employee Incentive Plan (232380)	12,261,080	(12,261,080)	0
86	DSM Tariff Rider (242600)	2,430,691	(2,430,691)	0

DISTRIBUTION OF SALARIES AND WAGES				
Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
87	Incentive/Stock Compensation (238000)	250,528		250,528
88	Payroll Equalization Liability (242700)	29,517,696		29,517,696
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	56,052,640	(23,251,769)	32,800,871
96	TOTAL SALARIES AND WAGES	240,605,484	0	240,605,484

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Electric Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to the order of the Commission or other authorization.

1 & 2. Common Plant in service and accumulated provision for depreciation

Acct. No.	Description	
303	Intangible	316,359,812
389	Land and Land Rights	14,462,378
390	Structures and Improvements	164,979,693
391	Office Furniture and Equipment	74,182,694
392	Transportation Equipment	14,898,130
393	Stores Equipment	6,073,212
394	Tools, Shop & Garage Equipment	17,935,919
395	Laboratory Equipment	1,325,251
396	Power Operated Equipment	1,895,320
397	Communications Equipment	131,869,530
398	Miscellaneous Equipment	847,230
399	Asset Retirement Cost	0
	Total Common Plant	744,829,169
	Const. Work in Progress	30,582,843
	Total Utility Plant	775,412,012
	Acc. Prov. for Dep. & Amort.	313,510,703
	Net Utility Plant	461,901,309

3. Common Expenses allocated to Electric and Gas departments:

Acct. No.	Description	Total	Allocation to Electric Dept	Allocated to Gas Dept	Basis of Allocation
901	Cust acct/collect supervision	259,884	135,418	124,466	# of Customers
902	Meter reading expenses	1,066,532	643,428	423,104	# of Customers
903	Cust rec & collectn expenses	15,808,108	8,346,776	7,461,332	# of Customers
904	Uncollectible accounts	163,701	85,300	78,401	# of Customers
905	Misc cust acct expenses	532,984	277,722	255,262	# of Customers
907	Cust svce & Info exp supervision	0	0	0	# of Customers
908	Cust assistance expenses	553,100	333,680	219,420	# of Customers
909	Info & instruct advert expenses	1,319,909	789,269	530,640	# of Customers
910	Misc cust serv & info expenses	439,617	229,071	210,546	# of Customers
911	Sales expense -supervision	0	0	0	# of Customers
912	Demo and selling expenses	0	0	0	# of Customers
913	Advertising expenses	0	0	0	# of Customers
916	Misc sales expenses	0	0	0	# of Customers
920	Admin & gen salaries	41,320,659	29,103,335	12,217,324	Four Factor
921	Office supplies & expenses	5,542,105	3,889,002	1,653,103	Four Factor
922	Admin expenses tranf-credit	0	0	0	Four Factor
923	Outside services employed	18,561,047	13,029,115	5,531,932	Four Factor
924	Property insurance	3,228,379	2,263,481	964,898	Four Factor
925	Injuries and damages	11,169,583	8,000,113	3,169,470	Four Factor
926	Employee pensions&benefits	80,949,342	56,832,975	24,116,367	Four Factor
927	Franchise requirement	0	0	0	Four Factor
928	Regulatory commission expenses	1,824,864	1,329,667	495,197	Four Factor
929	Duplicate charges-credit	0	0	0	Four Factor
930.1	General advertising expenses	0	0	0	Four Factor
930.2	Misc general expenses	6,252,505	4,407,862	1,844,643	Four Factor
931	Rents	737,859	522,629	215,230	Four Factor
935	Maint of general plant	17,501,188	12,440,091	5,061,097	Four Factor
403	Depreciation	25,657,540	18,217,879	7,439,661	Four Factor
404	Amort of LTD term plant	51,706,694	36,465,621	15,241,073	Four Factor

Note 1: The 4 factor allocator is made up of 25% each -customer counts, direct labor, direct O&M & Net direct plant

4. Letters of approval received from staffs of State Regulatory Commissions in 1993

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

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)	[(a)]14,114,368	[(b)]16,749,174	[(c)]23,078,449	[(d)]29,878,795
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	[(e)](4,665,163)	[(f)](6,160,591)	[(g)](8,524,549)	[(h)](9,911,431)
4	Transmission Rights				
5	Ancillary Services	1,441	(69,773)	(67,481)	(67,732)
6	Other Items (list separately)				
7	Other Charges - MRTU	415,938	711,443	1,027,499	1,029,411
8	Other Charges - EIM	(1,278,894)	(1,796,245)	(1,592,413)	(2,190,861)
46	TOTAL	8,587,690	9,434,008	13,921,505	18,738,182

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: IsoOrRtoSettlementsEnergyNetPurchasesPurchasedPower

CAISO - MRTU Purchases =$4,638,846

CAISO - EIM Purchases =$9,475,522

(b) Concept: IsoOrRtoSettlementsEnergyNetPurchasesPurchasedPower

CAISO - MRTU Purchases =$4,897,181

CAISO - EIM Purchases =$11,851,993

(c) Concept: IsoOrRtoSettlementsEnergyNetPurchasesPurchasedPower

CAISO - MRTU Purchases =$6,354,235

CAISO - EIM Purchases =$16,724,214

(d) Concept: IsoOrRtoSettlementsEnergyNetPurchasesPurchasedPower

CAISO - MRTU Purchases =$6,382,082

CAISO - EIM Purchases =$23,496,713

(e) Concept: IsoOrRtoSettlementsEnergyNetSales

CAISO - MRTU Sales =$301,222

CAISO - EIM Sales =$4,363,941

(f) Concept: IsoOrRtoSettlementsEnergyNetSales

CAISO - MRTU Sales =$338,911

CAISO - EIM Sales =$5,821,680

(g) Concept: IsoOrRtoSettlementsEnergyNetSales

CAISO - MRTU Sales =$420,000

CAISO - EIM Sales =$8,104,549

(h) Concept: IsoOrRtoSettlementsEnergyNetSales

CAISO - MRTU Sales =$439,129

CAISO - EIM Sales =$9,472,302

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year Usage - Related Billing Determinant Number of Units (b)	Amount Purchased for the Year Usage - Related Billing Determinant Unit of Measure (c)	Amount Purchased for the Year Usage - Related Billing Determinant Dollar (d)
1	Scheduling, System Control and Dispatch			
2	Reactive Supply and Voltage			
3	Regulation and Frequency Response			
4	Energy Imbalance			
5	Operating Reserve - Spinning			
6	Operating Reserve - Supplement			
7	Other	861	MW	(a)10,786,373
8	Total (Lines 1 thru 7)	861		10,786,373

PURCHASES AND SALES OF ANCILLARY SERVICES

Line No.	Amount Sold for the Year Usage - Related Billing Determinant Number of Units (e)	Amount Sold for the Year Usage - Related Billing Determinant Unit of Measure (f)	Amount Sold for the Year Usage - Related Billing Determinant Dollars (g)
1			
2			
3	89	MW	1,146,770
4			
5	1	MW	13,962
6	1	MW	12,863
7	861	MW	(b)10,786,373
8	952		11,959,968

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedAmount
Amounts reported are offsetting imputed amounts reflecting the self-provison of ancillary service for bundled retail native load customers under state jurisdiction.
(b) Concept: AncillaryServicesSoldAmount
Amounts reported are offsetting imputed amounts reflecting the self-provison of ancillary service for bundled retail native load customers under state jurisdiction.

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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: Avista Corporation									
1	January	3,134	30	8	1,672	458	619	15	385	85
2	February	2,871	24	8	1,621	450	619	14	181	426
3	March	2,571	6	8	1,355	345	627	12	244	0
4	Total for Quarter 1				4,648	1,253	1,865	41	810	511
5	April	2,844	19	8	1,261	312	632	13	639	345
6	May	2,438	21	18	1,285	274	637	19	242	642
7	June	2,741	28	18	1,389	299	631	21	422	373
8	Total for Quarter 2				3,935	885	1,900	53	1,303	1,360
9	July	2,853	6	18	1,479	321	634	31	419	99
10	August	3,055	16	18	1,701	377	636	27	341	285
11	September	2,353	14	18	1,173	247	627	23	306	389
12	Total for Quarter 3				4,353	945	1,897	81	1,066	773
13	October	2,919	30	8	1,341	328	626	28	624	323
14	November	2,906	29	18	1,635	363	619	10	289	371
15	December	2,827	10	18	1,309	317	619	11	582	152
16	Total for Quarter 4				4,285	1,008	1,864	49	1,495	846
17	Total				17,221	4,091	7,526	224	4,674	3,490

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2024-04-12	Year/Period of Report End of: 2023/ Q4

ELECTRIC ENERGY ACCOUNT

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)	9,307,869
3	Steam	1,950,137	23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear	0	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	3,521,491
5	Hydro-Conventional	3,024,124	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage	0	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	13,342
7	Other	3,134,299	27	Total Energy Losses	457,044
8	Less Energy for Pumping	0	27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	8,108,560	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	13,299,746
10	Purchases (other than for Energy Storage)	5,601,050			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	11,825			
13	Delivered	421,689			
14	Net Exchanges (Line 12 minus line 13)	(409,864)			
15	Transmission For Other (Wheeling)				
16	Received	4,446,353			
17	Delivered	4,446,353			
18	Net Transmission for Other (Line 16 minus line 17)	0			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	13,299,746			

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

MONTHLY PEAKS AND OUTPUT

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: Avista Corporation					
29	January	1,090,534	144,645	1,771	30	8
30	February	1,015,923	154,156	1,726	23	9
31	March	1,126,304	267,999	1,515	1	8
32	April	1,115,577	374,774	1,394	5	8
33	May	1,247,605	513,971	1,438	19	18
34	June	1,258,860	503,470	1,535	29	17
35	July	1,108,405	243,144	1,716	21	18
36	August	1,051,266	207,705	1,809	15	17
37	September	977,324	284,691	1,309	10	18
38	October	1,018,136	285,864	1,402	30	9
39	November	1,111,401	264,324	1,546	29	18
40	December	1,178,411	276,748	1,463	1	18
41	Total	13,299,746	3,521,491			

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

Steam Electric Generating Plant Statistics

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to 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: Boulder Park	Plant Name: Colstrip	Plant Name: Coyote Springs 2	Plant Name: Kettle Falls	Plant Name: Rathdrum	Plant Name: Spokane N.E.
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Internal Comb	Steam	Gas Turbine	Steam	Gas Turbine	Gas Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional	Not Applicable	Conventional	Not Applicable	Not Applicable
3	Year Originally Constructed	2002	1984	2003	1983	1995	1978
4	Year Last Unit was Installed	2002	1984	2003	1983	1995	1978
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	25	233	286	51	167	62
6	Net Peak Demand on Plant - MW (60 minutes)	26	228	319	95	172	53
7	Plant Hours Connected to Load	3,221	8,758	8,011	7,209	6,063	3
8	Net Continuous Plant Capability (Megawatts)	25	222	322	54	167	65
9	When Not Limited by Condenser Water	0	222	322	54	0	0
10	When Limited by Condenser Water	0	222	322	54	0	0
11	Average Number of Employees	2	252	32	26	1	1

12	Net Generation, Exclusive of Plant Use - kWh	63,905,000	1,641,846,000	2,265,353,000	308,291,000	779,307,000	112,000
13	Cost of Plant: Land and Land Rights	144,733	1,289,395	0	2,568,188	621,682	138,753
14	Structures and Improvements	1,312,452	111,860,988	11,800,944	29,619,893	3,739,982	746,178
15	Equipment Costs	32,775,846	220,053,648	192,808,126	113,479,534	61,667,377	13,596,464
16	Asset Retirement Costs	0	17,139,710	351,682	323,787	0	0
17	Total cost (total 13 thru 20)	34,233,031	350,343,741	204,960,752	145,991,402	66,029,041	14,481,395
18	Cost per KW of Installed Capacity (line 17/5) Including	1,369.32	1,503.62	716.65	2,862.58	395.38	233.57
19	Production Expenses: Oper, Supv, & Engr	24,753	74,600	660,721	102,576	23,440	22,796
20	Fuel	1,982,207	34,049,395	46,437,759	11,997,451	28,638,414	(4,255)
21	Coolants and Water (Nuclear Plants Only)						
22	Steam Expenses	0	3,592,098	0	629,880	0	0
23	Steam From Other Sources	0	0	0	0	0	0
24	Steam Transferred (Cr)	0	0	0	0	0	0
25	Electric Expenses	246,972	(144,667)	3,281,653	896,152	232,300	25,137
26	Misc Steam (or Nuclear) Power Expenses	30,548	5,887,656	594,939	481,021	23,881	9,010
27	Rents	0	0	103,105	0	0	0
28	Allowances	0	0	0	0	0	0
29	Maintenance Supervision and Engineering	66,187	274,399	295,267	99,377	83,153	28,570
30	Maintenance of Structures	2,577	744,875	89,483	125,790	46,898	91
31	Maintenance of Boiler (or reactor) Plant	0	5,125,679	0	1,964,813	0	0
32	Maintenance of Electric Plant	537,456	632,517	1,248,997	217,091	143,872	31,300
33	Maintenance of Misc Steam (or Nuclear) Plant	131,656	901,840	651,821	443,266	51,734	16,945
34	Total Production Expenses	3,022,356	51,138,392	53,363,745	16,957,417	29,243,692	129,594
35	Expenses per Net kWh	0.05	0.03	0.02	0.06	0.04	1.16

35	Plant Name	Boulder Park	Colstrip	Colstrip	Coyote Springs 2	Kettle Falls	Kettle Falls	Rathdrum	Spokane N.E.
36	Fuel Kind	Gas	Coal	Oil	Gas	Gas	Wood	Gas	Gas

37	Fuel Unit	MCF	Ton	BBL	MCF	MCF	Ton	MCF	MCF
38	Quantity (Units) of Fuel Burned	577,226	1,026,440	2,634	14,841,519	10,164	519,633	9,176,931	1,398
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1,020,000	16,970,000	5,880,000	1,020,000	1,020,000	8,600,000	1,020,000	1,020,000
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.43	32.8	145.36	3.13	0.76	23.07	3.12	(3.04)
41	Average Cost of Fuel per Unit Burned	3.43	32.8	145.36	3.13	0.76	23.07	3.12	(3.04)
42	Average Cost of Fuel Burned per Million BTU	3.37	1.93	24.72	3.07	0.75	2.68	3.06	(2.98)
43	Average Cost of Fuel Burned per kWh Net Gen	0.03	0.02	0	0.02	0.01	0.04	0.04	0
44	Average BTU per kWh Net Generation	9,213	10,619	0	6,683	0	14,540	12,011	12,732

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ 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.

Hydroelectric Generating Plant Statistics

Line No.	Item (a)	FERC Licensed Project No. 2058 Plant Name: Cabinet Gorge	FERC Licensed Project No. 2545 Plant Name: Little Falls	FERC Licensed Project No. 2545 Plant Name: Long Lake
1	Kind of Plant (Run-of-River or Storage)	Storage	Run-of-River	Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional	Conventional
3	Year Originally Constructed	1952	1910	1915
4	Year Last Unit was Installed	1953	1911	1924
5	Total installed cap (Gen name plate Rating in MW)	265	43	71
6	Net Peak Demand on Plant-Megawatts (60 minutes)	264	42	98
7	Plant Hours Connect to Load	8,748	6,830	7,034
8	Net Plant Capability (in megawatts)			
9	(a) Under Most Favorable Oper Conditions	255	43	90
10	(b) Under the Most Adverse Oper Conditions	295	43	90
11	Average Number of Employees	1	1	1
12	Net Generation, Exclusive of Plant Use - kWh	815,740,000	175,811,000	412,958,000
13	Cost of Plant			
14	Land and Land Rights	18,630,413	4,325,371	2,421,233
15	Structures and Improvements	27,320,551	5,533,346	11,205,708
16	Reservoirs, Dams, and Waterways	112,278,157	6,407,917	39,058,591
17	Equipment Costs	74,437,083	53,839,549	14,352,281
18	Roads, Railroads, and Bridges	1,864,637		
19	Asset Retirement Costs			
20	Total cost (total 13 thru 20)	234,530,841	70,106,183	67,037,813

Hydroelectric Generating Plant Statistics				
Line No.	Item (a)	FERC Licensed Project No. 2058 Plant Name: Cabinet Gorge	FERC Licensed Project No. 2545 Plant Name: Little Falls	FERC Licensed Project No. 2545 Plant Name: Long Lake
21	Cost per KW of Installed Capacity (line 20 / 5)	885.02	1,630.38	944.19
22	Production Expenses			
23	Operation Supervision and Engineering	63,004	43	41,352
24	Water for Power			
25	Hydraulic Expenses	3,430	7,932	7,932
26	Electric Expenses	1,045,515	720,542	800,519
27	Misc Hydraulic Power Generation Expenses	250,024	29,699	141,742
28	Rents	41	1,232,674	
29	Maintenance Supervision and Engineering	9,023	66	15,494
30	Maintenance of Structures	187,725	25,215	65,337
31	Maintenance of Reservoirs, Dams, and Waterways	185,833	102,811	40,102
32	Maintenance of Electric Plant	272,093	340,440	554,195
33	Maintenance of Misc Hydraulic Plant	50,256	1,006	14,181
34	Total Production Expenses (total 23 thru 33)	2,066,944	2,460,428	1,680,854
35	Expenses per net kWh	0	0.01	0

Line No.	FERC Licensed Project No. 2545 Plant Name: Monroe Street	FERC Licensed Project No. 2545 Plant Name: Nine Mile Falls	FERC Licensed Project No. 2058 Plant Name: Noxon Rapids	FERC Licensed Project No. 2545 Plant Name: Post Falls
1	Run-of-River	Run-of-River	Storage	Storage
2	Conventional	Conventional	Outdoor	Conventional
3	1890	1908	1959	1906
4	1992	1994	1977	1980
5	15	38	488	15
6	117	26	548	22
7	8,325	8,752	6,531	8,165
8				
9	15	38	581	18
10	15	38	623	18
11	4	6	11	5
12	89,124,000	118,300,000	1,304,311,000	47,966,000
13				
14	51,600	33,429	37,469,198	4,161,522
15	12,241,336	23,778,869	25,082,690	8,103,381
16	10,008,937	30,933,636	41,684,508	26,063,988
17	14,926,724	60,915,210	114,499,641	5,584,416
18	50,448	594,870	305,777	577,944
19				
20	37,279,045	116,256,014	219,041,814	44,491,251
21	2,485.27	3,059.37	448.86	2,966.08
22				
23	18,737	27,626	250,431	20,378
24				
25			88,094	3,195
26	588,796	890,537	1,034,512	839,497
27	17,286	155,938	831,554	114,711
28				
29	165,870	12,903	24,582	36,235
30	8,607	1,900	13,331	25,924
31	4,830	16,193	51,299	46,612
32	53,164	214,142	928,077	137,132

Hydroelectric Generating Plant Statistics				
Line No.	FERC Licensed Project No. 2545 Plant Name: Monroe Street	FERC Licensed Project No. 2545 Plant Name: Nine Mile Falls	FERC Licensed Project No. 2058 Plant Name: Noxon Rapids	FERC Licensed Project No. 2545 Plant Name: Post Falls
33	2,727	4,837	61,528	2,475
34	860,017	1,324,076	3,283,408	1,226,159
35	0.01	0.01	0	0.03

Hydroelectric Generating Plant Statistics

Line No.	FERC Licensed Project No. 2545 Plant Name: Upper Falls
1	Run-of-River
2	Conventional
3	1922
4	1922
5	10
6	20
7	8,760
8	
9	10
10	10
11	4
12	59,914,000
13	
14	1,081,854
15	4,960,136
16	10,046,229
17	5,449,312
18	508,242
19	
20	22,045,773
21	2,204.58
22	
23	18,214
24	
25	202
26	580,773
27	48,188
28	
29	17,818
30	32,444
31	13,957
32	46,892

Hydroelectric Generating Plant Statistics	
Line No.	FERC Licensed Project No. 2545 Plant Name: Upper Falls
33	2,309
34	760,797
35	0.01

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

GENERATING PLANT STATISTICS (Small Plants)

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)
1	Kettle Falls CT	2002	7.2	15	25,622,000	9,571,547

GENERATING PLANT STATISTICS (Small Plants)						
Line No.	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel Production Expenses (i)	Production Expenses Maintenance Production Expenses (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)
1	1,323,903	105,528	986,744	57,050	Natural Gas	342.01

GENERATING PLANT STATISTICS (Small Plants)

Line No.	Generation Type (m)
1	Gas Turbine

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

TRANSMISSION LINE STATISTICS

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase) Designated (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) - (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) - (In the case of underground lines report circuit miles) On Structures of Another Line (g)	Number of Circuits (h)
1	Group Sum - 60kV		60	60		1		
2	Group Sum - 115kV		115	115		1,569		
3	Beacon Sub #4	BPA Bell Sub	230	230	Steel Pole	1		1
4	Beacon Sub #4	BPA Bell Sub	230	230	H Type	5		1
5	Beacon Sub #5	BPA Bell Sub	230	230	Steel Tower	3		1
6	Beacon Sub #5	BPA Bell Sub	230	230	H Type	3		1
7	Beacon	Cabinet Gorge Plant	230	230	Steel Tower	1		1
8	Beacon	Cabinet Gorge Plant	230	230	Steel Pole	41		2
9	Beacon	Cabinet Gorge Plant	230	230	H Type	52		1
10	Beacon Sub	Lolo Sub	230	230	Steel Tower	1		1
11	Beacon Sub	Lolo Sub	230	230	Steel Pole	22		2
12	Beacon Sub	Lolo Sub	230	230	H Type	78		1
13	Beacon Sub	Lolo Sub	230	230	H Type	8		1
14	Benewah	Shawnee	230	230	Steel Pole	1		1
15	Benewah	Shawnee	230	230	Steel Pole	59		1
16	Noxon Plant	Pine Creek Sub	230	230	Steel Pole	29		1
17	Noxon Plant	Pine Creek Sub	230	230	H Type	1		1
18	Noxon Plant	Pine Creek Sub	230	230	H Type	14		1
19	Cabinet Gorge Plant	Noxon	230	230	H Type	2		1
20	Cabinet Gorge Plant	Noxon	230	230	H Type	17		1
21	Benewah Sw. Station	Pine Creek Sub	230	230	H Type	43		1
22	Divide Creek	Lolo Sub	230	230	H Type	10		1
23	Divide Creek	Lolo Sub	230	230	H Type	33		1
24	North Lewiston	Walla Walla	230	230	H Type	40		1
25	North Lewiston	Walla Walla	230	230	H Type	4		1

TRANSMISSION LINE STATISTICS

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase) Designated (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) - (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) - (In the case of underground lines report circuit miles) On Structures of Another Line (g)	Number of Circuits (h)
26	North Lewiston	Walla Walla	230	230	Steel Pole	4		1
27	North Lewiston	Shawnee	230	230	Steel Pole	7		1
28	North Lewiston	Shawnee	230	230	H Type	27		1
29	Saddle Mtn-Walla Walla	Wanapum	230	230	Steel Tower	2		1
30	Saddle Mtn-Walla Walla	Wanapum	230	230	H Type	33		1
31	Saddle Mtn-Walla Walla	Wanapum	230	230	H Type	46		1
32	BPA (Libby)	Noxon Plant	230	230	Steel Pole	1		1
33	BPA/Hot Springs #1	Noxon Plant	230	230	Steel Pole	1		1
34	BPA/Hot Springs #2	Noxon Plant	230	230	Steel Pole	2		1
35	BPA/Hot Springs #2	Noxon Plant	230	230	H Type	1		1
36	BPA/Hot Springs #2	Noxon Plant	230	230	H Type	66		1
37	Coulee	West Side Sub	230	230	Steel Pole	2		2
38	BPA Line	West Side Sub	230	230	Steel Pole	2		2
39	Hatwai	N. Lewiston Sub	230	230	H Type	7		1
40	Divide Creek	Imnaha	230	230	H Type	2		1
41	Divide Creek	Imnaha	230	230	H Type	2		1
42	Divide Creek	Imnaha	230	230	H Type	16		1
43	Colstrip Plant	Broadview	500	500		0		
36	TOTAL					2,259	0	44

TRANSMISSION LINE STATISTICS

Line No.	Size of Conductor and Material (i)	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way) Land (j)	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way) Construction Costs (k)	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way) Total Costs (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Maintenance Expenses (n)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Rents (o)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Total Expenses (p)
1		136,038	636,193	772,231				0
2		12,853,612	358,575,110	371,428,722	1,009,657	1,877,624		2,887,281
3	1272 ACSS			0				0
4	1272 ACSS	17,912	1,428,560	1,446,472	0	8,605		8,605
5	1272 ACSS			0				0
6	1272 ACSS	30,323	3,271,116	3,301,439	0	0		0
7	1590 ACSS			0				0
8	1590 ACSS			0				0
9	1590 ACSR	1,156,196	41,768,911	42,925,107	0	42,141		42,141
10	1590 ACSS			0				0
11	1590 ACSS			0				0
12	1272 AAC			0				0
13	1272 ACSS	456,162	33,607,469	34,063,631	0	9,298		9,298
14	1622 ACSS			0				0
15	1590 ACSS	570,207	47,971,774	48,541,981	0	0		0
16	1272 ACSR			0				0
17	1590 ACSS			0				0
18	954 AAC	1,098,606	17,920,790	19,019,396	3,453	89,645		93,098
19	795 ACSR			0				0
20	954 AAC	184,528	2,571,300	2,755,828	8,884	33,313		42,197
21	954 AAC	399,821	5,257,051	5,656,872	0	31,903		31,903
22	1590 ACSR			0				0
23	1272 AAC	167,484	21,687,001	21,854,485	0	72		72
24	1272 AAC			0				0
25	1272 ACSR			0				0
26	1272 ACSR	623,984	6,805,680	7,429,664	0	13,017		13,017
27	1272 ACSR			0				0
28	1272 ACSR	872,150	10,040,291	10,912,441	0	2,579		2,579
29	1590 ACSS			0				0

TRANSMISSION LINE STATISTICS

Line No.	Size of Conductor and Material (i)	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way) Land (j)	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way) Construction Costs (k)	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way) Total Costs (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Maintenance Expenses (n)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Rents (o)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Total Expenses (p)
30	1272 ACSR			0				0
31	1272 AAC	314,998	14,079,914	14,394,912	0	3,239		3,239
32	1272 ACSR			0				0
33	1272 ACSR	0	18,772	18,772	0	14,200		14,200
34	1272 ACSR			0				0
35	1622 ACSS			0				0
36	1272 AAC	3,604,460	11,242,280	14,846,740	6,932	17,748		24,680
37	1272 ACSR	8,482	0	8,482	0	0		0
38	1272 ACSR	36,461	1,442,964	1,479,425	0	0		0
39	1590 ACSR	155,244	2,221,192	2,376,436	0	128		128
40	1622 ACSS			0				0
41	1590 ACSR			0				0
42	1272 AAC	205,262	1,312,224	1,517,486	0	0		0
43		595,789	39,009,258	39,605,047	81,495	140,057	80,425	301,977
36		23,487,719	620,867,850	644,355,569	1,110,421	2,283,569	80,425	3,474,415

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

TRANSMISSION LINES ADDED DURING YEAR

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						

TRANSMISSION LINES ADDED DURING YEAR

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL					

TRANSMISSION LINES ADDED DURING YEAR

Line No.	CIRCUITS PER STRUCTURE Ultimate (g)	CONDUCTORS Size (h)	CONDUCTORS Specification (i)	CONDUCTORS Configuration and Spacing (j)	Voltage KV (Operating) (k)	LINE COST Land and Land Rights (l)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						

TRANSMISSION LINES ADDED DURING YEAR

Line No.	CIRCUITS PER STRUCTURE Ultimate (g)	CONDUCTORS Size (h)	CONDUCTORS Specification (i)	CONDUCTORS Configuration and Spacing (j)	Voltage KV (Operating) (k)	LINE COST Land and Land Rights (l)
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						

TRANSMISSION LINES ADDED DURING YEAR					
Line No.	LINE COST Poles, Towers and Fixtures (m)	LINE COST Conductors and Devices (n)	LINE COST Asset Retire. Costs (o)	LINE COST Total (p)	Construction (q)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					

TRANSMISSION LINES ADDED DURING YEAR

Line No.	LINE COST Poles, Towers and Fixtures (m)	LINE COST Conductors and Devices (n)	LINE COST Asset Retire. Costs (o)	LINE COST Total (p)	Construction (q)
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

SUBSTATIONS

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)
1	Airway Heights (WA)	Distribution	Unattended	115	13.8		24
2	Barker Road (WA)	Distribution	Unattended	115	13.8		12
3	Beacon (Trans. & Dist.) (WA)	Transmission	Unattended	230	115	13.8	536
4	Boulder (Trans. & Dist.) (WA)	Transmission	Unattended	230	115	13.8	318
5	Chester (WA)	Distribution	Unattended	115	13.8		24
6	Chewelah 115Kv (WA)	Distribution	Unattended	115	13.2		12
7	Colbert (WA)	Distribution	Unattended	115	13.8		12
8	College & Walnut (WA)	Distribution	Unattended	115	13.8		36
9	Colville 115 Kv (WA)	Distribution	Unattended	115	13.8		32
10	Critchfield (WA)	Distribution	Unattended	115	13.8		12
11	Davenport (WA)	Distribution	Unattended	115	13.8		12
12	Deer Park (WA)	Distribution	Unattended	115	13.8		12
13	Downriver (WA)	Distribution	Unattended	115	13.8		24
14	Dry Creek (WA)	Transmission	Unattended	230	115	13.8	150
15	Dry Gulch (WA)	Distribution	Unattended	115	13.8		12
16	East Colfax (WA)	Distribution	Unattended	115	13.8		12
17	East Farms (WA)	Distribution	Unattended	115	13.8		12
18	Flint Rd (WA)	Distribution	Unattended	115	13.8		36
19	Francis and Cedar (WA)	Distribution	Unattended	115	13.8		36
20	Gifford (WA)	Distribution	Unattended	115	34		16
21	Glenrose (WA)	Distribution	Unattended	115	13.8		12
22	Greenacres (WA)	Distribution	Unattended	115	13.8		18
23	Greenwood (WA)	Distribution	Unattended	115	13.8		12
24	Hallett & White (WA)	Distribution	Unattended	115	13.8		36
25	Indian Trail (WA)	Distribution	Unattended	115	13.8		12

SUBSTATIONS

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)
26	Kettle Falls (WA)	Distribution	Unattended	115	13.8		12
27	Lee & Reynolds (WA)	Distribution	Unattended	115	13.8		36
28	Liberty Lake (WA)	Distribution	Unattended	115	13.8		24
29	Lind (WA)	Distribution	Unattended	115	13.8		12
30	Little Falls 115/34 Kv (WA)	Distribution	Unattended	115	34		12
31	Lyons & Standard (WA)	Distribution	Unattended	115	13.8		36
32	Mead (WA)	Distribution	Unattended	115	13.8		18
33	Metro (WA)	Distribution	Unattended	115	13.8		24
34	Milan (WA)	Distribution	Unattended	115	13.8		24
35	Millwood (WA)	Distribution	Unattended	115	13.8		24
36	Ninth & Central (WA)	Distribution	Unattended	115	13.8		36
37	Northeast (WA)	Distribution	Unattended	115	13.8		24
38	Northwest (WA)	Distribution	Unattended	115	13.8		24
39	Opportunity (WA)	Distribution	Unattended	115	13.8		12
40	Othello (WA)	Distribution	Unattended	115	13.8		36
41	Post Street (WA)	Distribution	Unattended	115	13.8		60
42	Pound Lane (WA)	Distribution	Unattended	115	13.8		24
43	Ross Park (WA)	Distribution	Unattended	115	13.8		33
44	Roxboro (WA)	Distribution	Unattended	115	24		24
45	Saddle Mountain (WA)	Transmission	Unattended	230	115	13.8	150
46	Shawnee (WA)	Transmission	Unattended	230	115	13.8	150
47	Silver Lake (WA)	Distribution	Unattended	115	13.8		12
48	Southeast (WA)	Distribution	Unattended	115	13.8		36
49	South Othello (WA)	Distribution	Unattended	115	13.8		12
50	South Pullman (WA)	Distribution	Unattended	115	13.8		30
51	Spokane Industrial Park (WA)	Distribution	Unattended	115	13.8		24
52	Sunset (WA)	Distribution	Unattended	115	13.8		36

		SUBSTATIONS					
		Character of Substation	Character of Substation	VOLTAGE (In MVa)	VOLTAGE (In MVa)	VOLTAGE (In MVa)	
Line No.	Name and Location of Substation (a)	Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)
53	Terre View (WA)	Distribution	Unattended	115	13.8		12
54	Third & Hatch (WA)	Distribution	Unattended	115	13.8		54
55	Turner (WA)	Distribution	Unattended	115	13.8		36
56	Waikiki (WA)	Distribution	Unattended	115	13.8		24
57	West Side (WA)	Transmission	Unattended	230	115	13.8	300
58	Other: 26 Subs. less than 10MVA (WA)	Distribution	Unattended				157
59	Appleway (ID)	Distribution	Unattended	115	13.8		36
60	Avondale (ID)	Distribution	Unattended	115	13.8		12
61	Benewah (ID)	Transmission	Unattended	230	115	13.8	150
62	Big Creek (ID)	Distribution	Unattended	115	13.8		17
63	Blue Creek (ID)	Distribution	Unattended	115	13.8		12
64	Bunker Hill Limited (ID)	Distribution	Unattended	115	13.8		12
65	Cabinet Gorge (Switchyard) (ID)	Transmission	Unattended	230	115	13.8	75
66	Clark Fork (ID)	Distribution	Unattended	115	21.8		10
67	Coeur d' Alene 15th Ave. (ID)	Distribution	Unattended	115	13.8		36
68	Cottonwood (ID)	Distribution	Unattended	115	24.9		12
69	Dalton (ID)	Distribution	Unattended	115	13.8		36
70	Grangeville (ID)	Distribution	Unattended	115	13.8		24
71	Holbrook (ID)	Distribution	Unattended	115	13.8		12
72	Huetter (ID)	Distribution	Unattended	115	13.8		12
73	Idaho Road (ID)	Distribution	Unattended	115	13.8		12
74	Juliaetta (ID)	Distribution	Unattended	115	13.8		12
75	Kamiah (ID)	Distribution	Unattended	115	13.8		12
76	Kooskia (ID)	Distribution	Unattended	115	13.8		15
77	Lewiston Mill Rd (ID)	Distribution	Unattended	115	13.2		18
78	Lolo (Trans. & Dist.) (ID)	Transmission	Unattended	230	115	13.8	262
79	Moscow (ID)	Distribution	Unattended	115	13.8		24

SUBSTATIONS

Line No.	Name and Location of Substation (a)	Character of Substation Transmission or Distribution (b)	Character of Substation Attended or Unattended (b-1)	VOLTAGE (In MVa) Primary Voltage (In MVa) (c)	VOLTAGE (In MVa) Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa) Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)
80	Moscow 230 kV (Trans. & Dist.) (ID)	Transmission	Unattended	230	115	13.8	162
81	North Lewiston 230kV (Trans. & Dist.) (ID)	Transmission	Unattended	230	115		158
82	North Moscow (ID)	Distribution	Unattended	115	13.8		12
83	Oden (ID)	Distribution	Unattended	115	21.8		10
84	Oldtown (ID)	Distribution	Unattended	115	21.8		17
85	Orofino (ID)	Distribution	Unattended	115	24		20
86	Osburn (ID)	Distribution	Unattended	115	13.8		12
87	Pine Creek (Trans. & Dist.) (ID)	Transmission	Unattended	230	115	13.8	212
88	Pleasant View (ID)	Distribution	Unattended	115	13.8		12
89	Plummer (ID)	Distribution	Unattended	115	13.8		12
90	Post Falls (ID)	Distribution	Unattended	115	13.8		18
91	Potlatch (ID)	Distribution	Unattended	115	24.9		15
92	Prairie (ID)	Distribution	Unattended	115	13.8		12
93	Priest River (ID)	Distribution	Unattended	115	20.8		10
94	Rathdrum (Trans. & Dist.) (ID)	Transmission	Unattended	230	115	13.8	474
95	Sagle (ID)	Distribution	Unattended	115	21.8		12
96	Sandpoint (ID)	Distribution	Unattended	115	20.8		30
97	South Lewiston (ID)	Distribution	Unattended	115	13.8		27
98	Sweetwater (ID)	Distribution	Unattended	115	24.9		12
99	St. Maries (ID)	Distribution	Unattended	115	23.9		24
100	Tenth & Stewart (ID)	Distribution	Unattended	115	13.8		30
101	Other: 13 Subs less than 10 MVA (ID)	Distribution	Unattended				72
102	Other: 1 Sub less than 10 MVA (MT)	Distribution	Unattended				5
103	Boulder Park (WA Gen. Plant)	Transmission	Attended	115	13.8		36
104	Kettle Falls (WA Gen. Plant)	Transmission	Attended	115	13.8		34

SUBSTATIONS							
		Character of Substation	Character of Substation	VOLTAGE (In MVa)	VOLTAGE (In MVa)	VOLTAGE (In MVa)	
Line No.	Name and Location of Substation (a)	Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)
105	Long Lake (WA Gen. Plant)	Transmission	Attended	115	4		80
106	Nine Mile (WA Gen. Plant)	Transmission	Attended	115	13.8		42
107	Little Falls (WA Gen. Plant)	Transmission	Attended	115	4		24
108	Northeast (WA Gen. Plant)	Transmission	Attended	115	13.8		36
109	Post Street (WA Gen. Plant)	Transmission	Attended	13.8	4		35
110	Cabinet Gorge (HED) (ID Gen. Plant)	Transmission	Attended	230	13.8		300
111	Post Falls (ID Gen. Plant)	Transmission	Attended	115	2.3		12
112	Rathdrum (ID Gen. Plant)	Transmission	Attended	115	13.8		114
113	Noxon (MT Gen. Plant)	Transmission	Attended	230	13.8		435
114	Coyote Springs II (OR Gen. Plant)	Transmission	Attended	500	13.8	18	270
115	Distribution Substations			9,890	1,335.8	0	2,040
116	Distribution Substations Unattended			9,890	1,335.8	0	2,040
117	Transmission Substations			4,883.8	1,619.7	183.60000000000002	4,515
118	Transmission Substations Attended			1,893.8	124.7	18	1,418
119	Transmission Substations Unattended			2,990	1,495	165.60000000000002	3,097
120	Total						6,555

SUBSTATIONS					
Line No.	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment Type of Equipment (i)	Conversion Apparatus and Special Equipment Number of Units (j)	Conversion Apparatus and Special Equipment Total Capacity (In MVa) (k)
1	2		Frcd Oil & Air Fan & Caps	39	40
2	1		Two Stage Fan	1	20
3	4		Two Stage Fan	2	560
4	3		Two Stage Fan	3	530
5	2		Frcd Oil & Air Fan	2	40
6	1		Two Stage Fan	1	20
7	1		Frcd Oil & Air Fan & Caps	16	20
8	2		Two Stage Fan	2	60
9	3		Frcd Oil & Air Fan	3	49
10	1		Two Stage Fan	1	20
11	1		Frcd Oil & Air Fan	1	20
12	1		Two Stage Fan	1	20
13	2		Frcd Oil & Air & Two Stage Fan	2	40
14	1		Two Stage Fan & Caps	224	250
15	1		Frcd Oil & Air Fan	1	20
16	1		Frcd Oil & Air Fan	1	20
17	1		Two Stage Fan	1	20
18	2		Two Stage Fan	2	60
19	2		Two Stage Fan	2	60
20	2		One Stage Fan	1	17
21	1		Frcd Oil & Air Fan	1	20
22	1		Two Stage Fan	1	30
23	1		Two Stage Fan	1	20
24	2		Two Stage Fan	2	60
25	1		Two Stage Fan	1	20
26	1		Frcd Oil & Air Fan	1	20
27	2		Two Stage Fan	2	60
28	2		Two Stage Fan	2	40
29	1		Two Stage Fan	1	20
30	1				
31	2		Two Stage Fan	2	60

SUBSTATIONS					
Line No.	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment Type of Equipment (i)	Conversion Apparatus and Special Equipment Number of Units (j)	Conversion Apparatus and Special Equipment Total Capacity (In MVa) (k)
32	1		Two Stage Fan	1	30
33	2		Two Stage Fan	2	40
34	2		Frcd Oil & Air Fan	2	40
35	2		Two Stage Fan	2	40
36	2		Two Stage Fan	2	60
37	2		Two Stage Fan	2	40
38	2		Two Stage Fan	2	40
39	1		Two Stage Fan	1	20
40	2		Two Stage Fan	2	60
41	2		Frcd Oil	2	60
42	2		Two Stage Fan	2	40
43	2		Two Stage Fan	2	57
44	2		Two Stage Fan	2	40
45	1		Two Stage Fan	1	250
46	1		Two Stage Fan	1	250
47	1		Two Stage Fan	1	20
48	2		Two Stage Fan	2	60
49	1		Two Stage Fan	1	20
50	2		Two Stage Fan	2	50
51	2		Two Stg, Frcd Oil Fan & Caps	14	40
52	2		Two Stage Fan & Caps	50	60
53	1		Two Stage Fan	1	20
54	3		Two Stage Fan & Caps	103	90
55	2		Two Stage Fan	2	60
56	2		Two Stage Fan	2	40
57	2		Two Stage Fan	2	500
58	27				
59	2		Two Stage Fan	2	60
60	1		Two Stage Fan	1	20
61	1		Two Stage Fan & Caps	224	250
62	2		Portable Fan	2	22

SUBSTATIONS					
Line No.	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment Type of Equipment (i)	Conversion Apparatus and Special Equipment Number of Units (j)	Conversion Apparatus and Special Equipment Total Capacity (In MVa) (k)
63	1		Two Stage Fan	1	20
64	1		Frcd Air Fan	1	16
65	1		Two Stage Fan	1	125
66	1		Frcd Air Fan	1	12
67	2		Two Stage Fan	2	60
68	1		Two Stage Fan	1	20
69	2		Two Stage Fan	2	60
70	4		Frcd Oil & Air & Pt Fan & Caps	17	34
71	1		Two Stage Fan	1	20
72	1		Two Stage Fan	1	20
73	1		Two Stage Fan	1	20
74	1		Frcd Oil & Air Fan	1	20
75	1		Two Stage Fan	1	20
76	3		Frcd Air Fan	3	20
77	1		Two Stage Fan	1	30
78	3		Frcd Oil & Air Fan & Two Stage Fan	1	270
79	2		Frcd Oil & Air & Two Stage	2	40
80	2		Two Stage Fan & Caps	76	270
81	2		Frcd Air Fan & Caps & Two Stage Fan	50	259
82	1		Two Stage Fan	1	20
83	1		Frcd Air Fan	1	12
84	2		Frcd Air Fan	2	22
85	2		Frcd Oil & Air Fan	1	28
86	1		Portable Fan	1	15
87	3		Two Stage Fan & Caps	47	270
88	1		Two Stage Fan	1	20
89	1		Two Stage Fan	1	20
90	1		Two Stage Fan	1	30
91	2		Portable Fan	2	19
92	1		Frcd Oil & Air Fan	1	20

SUBSTATIONS					
Line No.	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment Type of Equipment (i)	Conversion Apparatus and Special Equipment Number of Units (j)	Conversion Apparatus and Special Equipment Total Capacity (In MVa) (k)
93	1		Frcd Air Fan	1	13
94	4		Frcd Oil & Air Fan & Caps	39	490
95	1		Two Stage Fan	1	20
96	3		Frcd Air Fan	3	38
97	4		Portable Fan, Frcd Oil & Air	4	39
98	1		Frcd Oil & Air Fan	1	20
99	2		Two Stage Fan	2	40
100	2		Frcd Oil & Air & Two Stage	2	50
101	13				
102	1				
103	1		Two Stage Fan	1	60
104	1	1	Two Stage Fan	1	62
105	4	1			
106	2		Two Stage Fan	1	56
107	2		Frcd Oil & Air Fan	2	40
108	1		Two Stage Fan	1	60
109	2				
110	6	1			
111	1		Frcd Air & Oil & Air Fan	1	16
112	2	1	Two Stage Fan	2	190
113	9	1	Two Stage Fan	6	635
114	3	2	Two Stage Fan	3	450
115	179	0		360	2,863
116	179	0		360	2,863
117	62	7		689	5,843
118	34	7		18	1,569
119	28	0		671	4,274
120					

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/12/2024	Year/Period of Report End of: 2023/ Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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				
3				
4				
5				
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14				
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16				
17				
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19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Corporate Support	Avista Development	146000	200,750
22	Corporate Support	Avista Capital	146000	65,093
23	Corporate Support	AELP	146000	34,020
24	Corporate Support	AJT Mining	146000	1,561
25	Corporate Support	Avista Edge	146000	160,199
42				