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

RECEIVED
APRIL 17, 2026
IDAHO PUBLIC
UTILITIES COMMISSION

# 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: 2025/ 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<br>Avista Corporation | 02 Year/ Period of Report<br>End of: 2025/ Q4 |
| 03 Previous Name and Date of Change (If name changed during year)<br>/ | |
| 04 Address of Principal Office at End of Period (Street, City, State, Zip Code)<br>1411 East Mission Avenue, Spokane, WA 99207 | |
| 05 Name of Contact Person<br>Ryan L. Krasselt | 06 Title of Contact Person<br>VP, Controller, Prin. Acctg Officer |
| 07 Address of Contact Person (Street, City, State, Zip Code)<br>1411 East Mission Avenue, Spokane, WA 99207 | |

| | | |
|---|---|---|
| 08 Telephone of Contact Person, Including Area Code<br>(509) 495-2273 | 09 This Report is An Original / A Resubmission<br>(1) ☑ An Original<br>(2) ☐ A Resubmission | 10 Date of Report (Mo, Da, Yr)<br>04/17/2026 |

**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<br>Ryan L. Krasselt | 03 Signature<br>Ryan L. Krasselt | 04 Date Signed (Mo, Da, Yr)<br>04/17/2026 |
| 02 Title<br>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: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

**LIST OF SCHEDULES (Electric Utility)**

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

| Name of Respondent:<br>Avista Corporation | This report is:<br>(1) ☑ An Original<br>(2) ☐ A Resubmission | Date of Report:<br>04/17/2026 | Year/Period of Report<br>End of: 2025/ Q4 |
|---|---|---|---|

## GENERAL INFORMATION

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

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: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## CORPORATIONS CONTROLLED BY RESPONDENT

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

Definitions

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

| Line No. | Name of Company Controlled (a) | Kind of Business (b) | Percent Voting Stock Owned (c) | Footnote Ref. (d) |
|---|---|---|---|---|
| 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: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## OFFICERS

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

| Line No. | Title (a) | Name of Officer (b) | Salary for Year (c) | Date Started in Period (d) | Date Ended in Period (e) |
|---|---|---|---|---|---|
| 1 | President and Chief Executive Officer | H.L. Rosentrater | 786,845 | 2025-01-01 | 2025-12-31 |
| 2 | Senior Vice President, Chief Financial Officer, Treasurer and Regulatory Affairs Officer | K.J. Christie | 468,269 | 2025-01-01 | 2025-12-31 |
| 3 | Senior Vice President, Growth, Energy Policy and External Relations | J.R. Thackston | 414,692 | 2025-01-01 | 2025-12-31 |
| 4 | Senior Vice President, General Council, Corporate Secretary and Chief Ethics/ Compliance Officer | G.C. Hesler | 443,576 | 2025-01-01 | 2025-12-31 |
| 5 | Senior Vice President, Safety and Chief People Officer | B.A. Cox | 379,884 | 2025-01-01 | 2025-12-31 |
| 6 | Vice President, Community Affairs and Chief Customer Officer | L.D. Hill | 353,886 | 2025-01-01 | 2025-12-31 |
| 7 | Vice President, Controller and Principal Accounting Officer | R.L. Krasselt | 298,270 | 2025-01-01 | 2025-12-31 |
| 8 | Senior Vice President, Operations and Technology | W.O. Manuel | 404,269 | 2025-01-01 | 2025-12-31 |
| 9 | Vice President, Energy Resources and Integrated Planning | S.J. Kinney | 344,230 | 2025-01-01 | 2025-12-31 |
| 10 | Vice President, Energy Delivery | J.D. DiLuciano | 285,770 | 2025-01-01 | 2025-12-31 |
| 11 | Vice President, Chief Information and Security Officer | A.G. Alexander | 248,781 | 2025-10-01 | 2025-12-31 |
| 12 | Vice President and Chief Counsel for Regulatory and Governmental Affairs | D.J. Meyer | 354,077 | 2025-01-01 | 2025-12-31 |

**DIRECTORS**

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

| Line No. | Name (and Title) of Director (a) | Principal Business Address (b) | Member of the Executive Committee (c) | Chairman of the Executive Committee (d) |
|---|---|---|---|---|
| 1 | Scott L. Morris (Chairman of the Board) | 1411 E. Mission Ave, Spokane, WA 99202 | true | true |
| 2 | Heather L Rosentrater (President and CEO) | 1411 E. Mission Ave, Spokane, WA 99202 | true | false |
| 3 | Donald C. Burke | 1411 E. Mission Ave, Spokane, WA 99202 | true | false |
| 4 | Scott H. Maw | 1411 E. Mission Ave, Spokane, WA 99202 | false | false |
| 5 | Rebecca A. Klein | 1411 E. Mission Ave, Spokane, WA 99202 | false | false |
| 6 | Jeffry L. Philipps | 1411 E. Mission Ave, Spokane, WA 99202 | false | false |
| 7 | Heidi B. Stanley | 1411 E. Mission Ave, Spokane, WA 99202 | true | false |
| 8 | Janet D. Widmann | 1411 E. Mission Ave, Spokane, WA 99202 | false | false |
| 9 | Julie A. Bentz | 1411 E. Mission Ave, Spokane, WA 99202 | false | false |
| 10 | Sena M. Kwawu | 1411 E. Mission Ave, Spokane, WA 99202 | false | false |
| 11 | Kevin B. Jacobsen | 1411 E. Mission Ave, Spokane, WA 99202 | false | false |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

**IMPORTANT CHANGES DURING THE QUARTER/YEAR**

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

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

None.

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 4.5 percent for non-exempt employees and 4.9 percent for exempt employees, effective March 10, 2025. Officers received average increases of 5.3 percent (excluding our new CEO, who received a larger increase due to her transition) effective February 24, 2025. Bargaining Unit employees annual wage increase is effective on January 1, 2025 in the amount of 5 percent.

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

10. None.

13. Effective October 1, 2025, the following leadership changes occurred:

**Jason Thackston**, formerly Senior Vice President of Energy Policy and Chief Strategy Officer took on expanded responsibilities. To reflect the change in focus his new title is now Senior Vice President of Growth, Energy Policy, and External Relations. In this broader role, Mr. Thackston not only oversees energy policy and external relations but also drives company-wide growth initiatives.

**Wayne Manuel**, formerly Vice President, Chief Information Officer and Chief Security Officer, was promoted to Senior Vice President, Operations and Technology. In this expanded role, Mr. Manuel reports directly to President and CEO Heather Rosentrater and oversees energy delivery operations and technology initiatives.

**Alexis Alexander**, formerly Director of Applications, succeeded Mr. Manuel as the Vice President, Chief Information Officer/Chief Security Officer, and now reports to Mr. Manuel. Mr. Alexander now leads Avista's information systems and cybersecurity strategy, ensuring continued innovation and resilience across the company's digital infrastructure.

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: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

| Line No. | Title of Account (a) | Ref. Page No. (b) | Current Year End of Quarter/Year Balance (c) | Prior Year End Balance 12/31 (d) |
|---|---|---|---|---|
| 1 | **UTILITY PLANT** | | | |
| 2 | Utility Plant (101-106, 114) | 200 | 8,607,151,538 | 8,212,758,967 |
| 3 | Construction Work in Progress (107) | 200 | 283,713,025 | 206,589,639 |
| 4 | TOTAL Utility Plant (Enter Total of lines 2 and 3) | | 8,890,864,563 | 8,419,348,606 |
| 5 | (Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115) | 200 | 3,132,651,306 | 2,959,941,113 |
| 6 | Net Utility Plant (Enter Total of line 4 less 5) | | 5,758,213,257 | 5,459,407,493 |
| 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) | | 5,758,213,257 | 5,459,407,493 |
| 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) | | 1,670,260 | 22,724,548 |
| 19 | (Less) Accum. Prov. for Depr. and Amort. (122) | | 48,803 | 114,549 |
| 20 | Investments in Associated Companies (123) | | 11,547,000 | 11,547,000 |
| 21 | Investment in Subsidiary Companies (123.1) | 224 | 254,601,206 | 261,742,212 |
| 23 | Noncurrent Portion of Allowances and Environmental Credits | 228 | 0 | |
| 24 | Other Investments (124) | | 14,094 | 14,094 |
| 25 | Sinking Funds (125) | | 0 | 0 |
| 26 | Depreciation Fund (126) | | 0 | 0 |
| 27 | Amortization Fund - Federal (127) | | 0 | 0 |
| 28 | Other Special Funds (128) | | 25,511,152 | 21,331,917 |
| 29 | Special Funds (Non Major Only) (129) | | 0 | 0 |
| 30 | Long-Term Portion of Derivative Assets (175) | | 0 | 0 |
| 31 | Long-Term Portion of Derivative Assets - Hedges (176) | | 0 | 0 |
| 32 | TOTAL Other Property and Investments (Lines 18-21 and 23-31) | | 293,294,909 | 317,245,222 |
| 33 | **CURRENT AND ACCRUED ASSETS** | | | |
| 34 | Cash and Working Funds (Non-major Only) (130) | | 0 | 0 |
| 35 | Cash (131) | | 1,248,093 | 2,733,182 |
| 36 | Special Deposits (132-134) | | 2,146,133 | 0 |
| 37 | Working Fund (135) | | 54,792 | 1,108,576 |
| 38 | Temporary Cash Investments (136) | | 10,484,697 | 19,917,239 |
| 39 | Notes Receivable (141) | | 0 | 0 |
| 40 | Customer Accounts Receivable (142) | | 201,272,552 | 189,162,196 |
| 41 | Other Accounts Receivable (143) | | 53,941,046 | 43,278,432 |
| 42 | (Less) Accum. Prov. for Uncollectible Acct.-Credit (144) | | 4,717,673 | 4,804,889 |
| 43 | Notes Receivable from Associated Companies (145) | | 23,326,169 | 29,187,996 |
| 44 | Accounts Receivable from Assoc. Companies (146) | | 932,546 | 85,106 |
| 45 | Fuel Stock (151) | 227 | 3,558,417 | 6,331,080 |
| 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 | 84,488,067 | 101,576,700 |
| 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 and Environmental Credits (158.1, 158.2, 158.3, and 158.4) | 228 | 4,981,232 | 1,175,388 |
| 53 | (Less) Noncurrent Portion of Allowances and Environmental Credits | 228 | 0 | |
| 54 | Stores Expense Undistributed (163) | 227 | 0 | 0 |
| 55 | Gas Stored Underground - Current (164.1) | | 8,159,164 | 10,258,810 |
| 56 | Liquefied Natural Gas Stored and Held for Processing (164.2-164.3) | | 0 | 0 |
| 57 | Prepayments (165) | | 49,937,035 | 29,781,526 |
| 58 | Advances for Gas (166-167) | | 0 | 0 |
| 59 | Interest and Dividends Receivable (171) | | 5,483,608 | 4,053,293 |

| | | | | |
|---|---|---|---|---|
| 60 | Rents Receivable (172) | | 6,784,615 | 6,058,492 |
| 61 | Accrued Utility Revenues (173) | | 0 | 0 |
| 62 | Miscellaneous Current and Accrued Assets (174) | | 17,912 | 10,090 |
| 63 | Derivative Instrument Assets (175) | | 8,101,017 | 11,061,997 |
| 64 | (Less) Long-Term Portion of Derivative Instrument Assets (175) | | 0 | 0 |
| 65 | Derivative Instrument Assets - Hedges (176) | | 0 | 0 |
| 66 | (Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176) | | 0 | 0 |
| 67 | Total Current and Accrued Assets (Lines 34 through 66) | | 460,199,422 | 450,975,214 |
| 68 | **DEFERRED DEBITS** | | | |
| 69 | Unamortized Debt Expenses (181) | | 20,899,066 | 21,102,539 |
| 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 | 860,140,083 | 893,411,579 |
| 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) | | 461,743 | 691,571 |
| 77 | Temporary Facilities (185) | | 0 | 0 |
| 78 | Miscellaneous Deferred Debits (186) | 233 | 188,981,436 | 104,072,323 |
| 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) | | 4,763,132 | 5,232,161 |
| 82 | Accumulated Deferred Income Taxes (190) | 234 | 167,004,425 | 154,122,918 |
| 83 | Unrecovered Purchased Gas Costs (191) | | (33,419,994) | (24,996,804) |
| 84 | Total Deferred Debits (lines 69 through 83) | | 1,208,829,891 | 1,153,636,287 |
| 85 | TOTAL ASSETS (lines 14-16, 32, 67, and 84) | | 7,727,529,555 | 7,388,256,292 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

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

| Line No. | Title of Account (a) | Ref. Page No. (b) | Current Year End of Quarter/Year Balance (c) | Prior Year End Balance 12/31 (d) |
|---|---|---|---|---|
| 1 | **PROPRIETARY CAPITAL** | | | |
| 2 | Common Stock Issued (201) | 250 | 1,748,263,267 | 1,667,222,874 |
| 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) | (2,732,405) |
| 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 | (59,877,267) | (55,172,369) |
| 11 | Retained Earnings (215, 215.1, 216) | 118 | 873,359,065 | 831,698,463 |
| 12 | Unappropriated Undistributed Subsidiary Earnings (216.1) | 118 | 31,111,114 | 39,097,599 |
| 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) | (546,442) | 355,480 |
| 16 | Total Proprietary Capital (lines 2 through 15) | | 2,709,331,866 | 2,590,814,380 |
| 17 | **LONG-TERM DEBT** | | | |
| 18 | Bonds (221) | 256 | 2,663,700,000 | 2,543,700,000 |
| 19 | (Less) Reacquired Bonds (222) | 256 | 0 | 0 |
| 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) | | 88,833 | 97,717 |
| 23 | (Less) Unamortized Discount on Long-Term Debt-Debit (226) | | 704,155 | 749,866 |
| 24 | Total Long-Term Debt (lines 18 through 23) | | 2,714,631,678 | 2,594,594,851 |
| 25 | **OTHER NONCURRENT LIABILITIES** | | | |
| 26 | Obligations Under Capital Leases - Noncurrent (227) | | 60,109,469 | 61,843,479 |
| 27 | Accumulated Provision for Property Insurance (228.1) | | 0 | 0 |
| 28 | Accumulated Provision for Injuries and Damages (228.2) | | 345,000 | 1,245,000 |
| 29 | Accumulated Provision for Pensions and Benefits (228.3) | | 64,818,750 | 74,523,208 |
| 30 | Accumulated Miscellaneous Operating Provisions (228.4) | | 0 | 0 |
| 31 | Accumulated Provision for Rate Refunds (229) | | 12,439,955 | 447,773 |
| 32 | Long-Term Portion of Derivative Instrument Liabilities | | 10,595,417 | 11,967,539 |
| 33 | Long-Term Portion of Derivative Instrument Liabilities - Hedges | | 0 | 0 |
| 34 | Asset Retirement Obligations (230) | | 16,425,032 | 18,173,105 |
| 35 | Total Other Noncurrent Liabilities (lines 26 through 34) | | 164,733,623 | 168,200,104 |
| 36 | **CURRENT AND ACCRUED LIABILITIES** | | | |
| 37 | Notes Payable (231) | | 385,000,000 | 342,000,000 |
| 38 | Accounts Payable (232) | | 161,722,605 | 122,286,620 |
| 39 | Notes Payable to Associated Companies (233) | | 0 | 0 |
| 40 | Accounts Payable to Associated Companies (234) | | 0 | 0 |
| 41 | Customer Deposits (235) | | 18,587,284 | 13,883,447 |
| 42 | Taxes Accrued (236) | 262 | 33,159,480 | 33,241,269 |
| 43 | Interest Accrued (237) | | 25,428,914 | 22,596,692 |
| 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) | | 319,461 | 397,222 |
| 48 | Miscellaneous Current and Accrued Liabilities (242) | | 81,576,703 | 75,770,212 |
| 49 | Obligations Under Capital Leases-Current (243) | | 4,552,504 | 4,519,343 |
| 50 | Derivative Instrument Liabilities (244) | | 27,967,207 | 26,352,702 |
| 51 | (Less) Long-Term Portion of Derivative Instrument Liabilities | | 10,595,417 | 11,967,539 |
| 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) | | 727,718,741 | 629,079,968 |
| 55 | **DEFERRED CREDITS** | | | |
| 56 | Customer Advances for Construction (252) | | 8,075,722 | 6,506,104 |
| 57 | Accumulated Deferred Investment Tax Credits (255) | 266 | 27,276,718 | 28,097,819 |
| 58 | Deferred Gains from Disposition of Utility Plant (256) | | 0 | 0 |

| | | | | |
|---|---|---|---|---|
| 59 | Other Deferred Credits (253) | 269 | 39,649,512 | 33,705,422 |
| 60 | Other Regulatory Liabilities (254) | 278 | 410,565,976 | 452,664,319 |
| 61 | Unamortized Gain on Reacquired Debt (257) | | 698,686 | 820,535 |
| 62 | Accum. Deferred Income Taxes-Accel. Amort.(281) | 272 | 0 | 0 |
| 63 | Accum. Deferred Income Taxes-Other Property (282) | | 678,056,060 | 657,327,906 |
| 64 | Accum. Deferred Income Taxes-Other (283) | | 246,790,973 | 226,444,884 |
| 65 | Total Deferred Credits (lines 56 through 64) | | 1,411,113,647 | 1,405,566,989 |
| 66 | TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65) | | 7,727,529,555 | 7,388,256,292 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

**STATEMENT OF INCOME**

Quarterly

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

Annual or Quarterly if applicable

6. Do not report fourth quarter data in columns (e) and (f)
7. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
8. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11. Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

| Line No. | Title of Account (a) | (Ref.) Page No. (b) | Total Current Year to Date Balance for Quarter/Year (c) | Total Prior Year to Date Balance for Quarter/Year (d) | Current 3 Months Ended - Quarterly Only - No 4th Quarter (e) | Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f) | Electric Utility Current Year to Date (in dollars) (g) | Electric Utility Previous Year to Date (in dollars) (h) | Gas Utiity Current Year to Date (in dollars) (i) | Gas Utility Previous Year to Date (in dollars) (j) | Other Utility Current Year to Date (in dollars) (k) | Other Utility Previous Year to Date (in dollars) (l) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | UTILITY OPERATING INCOME | | | | | | | | | | | |
| 2 | Operating Revenues (400) | 300 | 1,946,238,656 | 1,932,090,931 | | | 1,371,922,864 | 1,326,892,156 | 574,315,792 | 605,198,775 | | |
| 3 | Operating Expenses | | | | | | | | | | | |
| 4 | Operation Expenses (401) | 320 | 1,055,338,976 | 1,151,916,199 | | | 706,894,300 | 753,625,794 | 348,444,676 | 398,290,405 | | |
| 5 | Maintenance Expenses (402) | 320 | 104,847,175 | 86,506,944 | | | 89,562,795 | 71,891,225 | 15,284,380 | 14,615,719 | | |
| 6 | Depreciation Expense (403) | 336 | 229,046,971 | 199,439,998 | | | 180,385,878 | 153,386,157 | 48,661,093 | 46,053,841 | | |
| 7 | Depreciation Expense for Asset Retirement Costs (403.1) | 336 | 0 | 0 | | | 0 | 0 | 0 | 0 | | |
| 8 | Amort. & Depl. of Utility Plant (404-405) | 336 | 53,828,130 | 64,711,332 | | | 38,834,451 | 49,179,154 | 14,993,679 | 15,532,178 | | |
| 9 | Amort. of Utility Plant Acq. Adj. (406) | 336 | 0 | 0 | | | 0 | 0 | 0 | 0 | | |
| 10 | Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407) | | 0 | 0 | | | 0 | | 0 | | | |
| 11 | Amort. of Conversion Expenses (407.2) | | 0 | 0 | | | 0 | | 0 | | | |
| 12 | Regulatory Debits (407.3) | | 167,429,007 | 92,390,929 | | | 48,051,729 | 29,114,169 | 119,377,278 | 63,276,760 | | |
| 13 | (Less) Regulatory Credits (407.4) | | 162,721,653 | 102,105,265 | | | 59,984,954 | 50,294,571 | 102,736,699 | 51,810,694 | | |
| 14 | Taxes Other Than Income Taxes (408.1) | 262 | 130,845,925 | 120,874,933 | | | 93,368,201 | 83,037,800 | 37,477,724 | 37,837,133 | | |
| 15 | Income Taxes - Federal (409.1) | 262 | 24,228,439 | 8,736,878 | | | 2,777,191 | (11,228,757) | 21,451,248 | 19,965,635 | | |
| 16 | Income Taxes - Other (409.1) | 262 | 866,023 | 1,186,219 | | | 21,511 | 20,284 | 844,512 | 1,165,935 | | |
| 17 | Provision for Deferred Income Taxes (410.1) | 234, 272 | 33,811,582 | 58,356,281 | | | 30,932,138 | 45,633,776 | 2,879,444 | 12,722,505 | | |
| 18 | (Less) Provision for Deferred Income Taxes-Cr. (411.1) | 234, 272 | 31,221,310 | 65,245,950 | | | 11,837,849 | 31,152,894 | 19,383,461 | 34,093,056 | | |
| 19 | Investment Tax Credit Adj. - Net (411.4) | 266 | (821,101) | (135,343) | | | (816,379) | (130,623) | (4,722) | (4,720) | | |
| 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 | | | | | | | | |
| 24.1 | (Less) Gains from Disposition of Environmental Credits (411.11) | | 0 | | | | 0 | | | | | |
| 24.2 | Losses from Disposition of Environmental Credits (411.12) | | 0 | | | | 0 | | | | | |
| 25 | TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24.2) | | 1,605,478,164 | 1,616,633,155 | | | 1,118,189,012 | 1,093,081,514 | 487,289,152 | 523,551,641 | 0 | 0 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 27 | Net Util Oper Inc (Enter Tot line 2 less 25) | | 340,760,492 | 315,457,776 | | | 253,733,852 | 233,810,642 | 87,026,640 | 81,647,134 | 0 | 0 |
| 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) | | 121,753 | 11,937 | | | | | | | | |
| 34 | (Less) Expenses of Nonutility Operations (417.1) | | 10,821,557 | 13,762,536 | | | | | | | | |
| 35 | Nonoperating Rental Income (418) | | (1,178) | (1,513) | | | | | | | | |
| 36 | Equity in Earnings of Subsidiary Companies (418.1) | 119 | (7,141,006) | 1,531,571 | | | | | | | | |
| 37 | Interest and Dividend Income (419) | | 13,927,194 | 17,033,145 | | | | | | | | |
| 38 | Allowance for Other Funds Used During Construction (419.1) | | 213,268 | 127,811 | | | | | | | | |
| 39 | Miscellaneous Nonoperating Income (421) | | 4,095 | 17,485 | | | | | | | | |
| 40 | Gain on Disposition of Property (421.1) | | 5,727 | 1,974,406 | | | | | | | | |
| 41 | TOTAL Other Income (Enter Total of lines 31 thru 40) | | (3,691,704) | 6,932,306 | | | | | | | | |
| 42 | Other Income Deductions | | | | | | | | | | | |
| 43 | Loss on Disposition of Property (421.2) | | 202,620 | 0 | | | | | | | | |
| 44 | Miscellaneous Amortization (425) | | 5,616 | 5,616 | | | | | | | | |
| 45 | Donations (426.1) | | 3,887,395 | 2,807,938 | | | | | | | | |
| 46 | Life Insurance (426.2) | | 2,018,969 | 2,491,193 | | | | | | | | |
| 47 | Penalties (426.3) | | 70,448 | 41,895 | | | | | | | | |
| 48 | Exp. for Certain Civic, Political & Related Activities (426.4) | | 1,764,719 | 1,728,138 | | | | | | | | |
| 49 | Other Deductions (426.5) | | 2,518,048 | 2,480,852 | | | | | | | | |
| 50 | TOTAL Other Income Deductions (Total of lines 43 thru 49) | | 10,467,815 | 9,555,632 | | | | | | | | |
| 51 | Taxes Applic. to Other Income and Deductions | | | | | | | | | | | |
| 52 | Taxes Other Than Income Taxes (408.2) | 262 | 675,362 | 2,046,797 | | | | | | | | |
| 53 | Income Taxes-Federal (409.2) | 262 | (3,145,743) | (4,610,911) | | | | | | | | |
| 54 | Income Taxes-Other (409.2) | 262 | (223,948) | (151,483) | | | | | | | | |
| 55 | Provision for Deferred Inc. Taxes (410.2) | 234, 272 | 4,745,191 | 7,514,751 | | | | | | | | |
| 56 | (Less) Provision for Deferred Income Taxes-Cr. (411.2) | 234, 272 | 2,940,567 | 4,206,684 | | | | | | | | |
| 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) | | (889,705) | 592,470 | | | | | | | | |
| 60 | Net Other Income and Deductions (Total of lines 41, 50, 59) | | (13,269,814) | (3,215,796) | | | | | | | | |
| 61 | Interest Charges | | | | | | | | | | | |
| 62 | Interest on Long-Term Debt (427) | | 119,053,107 | 115,125,685 | | | | | | | | |
| 63 | Amort. of Debt Disc. and Expense (428) | | 569,222 | 612,619 | | | | | | | | |
| 64 | Amortization of Loss on Reaquired Debt (428.1) | | 1,474,382 | 1,420,427 | | | | | | | | |
| 65 | (Less) Amort. of Premium on Debt-Credit (429) | | 8,883 | 8,883 | | | | | | | | |
| 66 | (Less) Amortization of Gain on Reaquired Debt-Credit (429.1) | | 0 | | | | | | | | | |
| 67 | Interest on Debt to Assoc. Companies (430) | | 2,192,352 | 2,575,297 | | | | | | | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 68 | Other Interest Expense (431) | | 22,894,794 | 23,608,892 | | | | | | | | |
| 69 | (Less) Allowance for Borrowed Funds Used During Construction-Cr. (432) | | 11,601,142 | 11,227,623 | | | | | | | | |
| 70 | Net Interest Charges (Total of lines 62 thru 69) | | 134,573,832 | 132,106,414 | | | | | | | | |
| 71 | Income Before Extraordinary Items (Total of lines 27, 60 and 70) | | 192,916,846 | 180,135,566 | | | | | | | | |
| 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) | | 192,916,846 | 180,135,566 | | | | | | | | |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## STATEMENT OF RETAINED EARNINGS

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

| Line No. | Item (a) | Contra Primary Account Affected (b) | Current Quarter/Year Year to Date Balance (c) | Previous Quarter/Year Year to Date Balance (d) |
|---|---|---|---|---|
| | UNAPPROPRIATED RETAINED EARNINGS (Account 216) | | | |
| 1 | Balance-Beginning of Period | | 772,267,474 | 741,321,490 |
| 2 | Changes | | | |
| 3 | Adjustments to Retained Earnings (Account 439) | | | |
| 4 | Adjustments to Retained Earnings Credit | | | |
| 4.1 | Dividends Received from Subs | | 0 | 5,000,000 |
| 4.2 | | | | |
| 4.3 | | | | |
| 4.4 | | | | |
| 4.5 | | | | |
| 4.6 | | | | |
| 4.7 | | | | |
| 4.8 | | | | |
| 4.9 | | | | |
| 4.10 | | | | |
| 4.11 | | | | |
| 9 | TOTAL Credits to Retained Earnings (Acct. 439) | | 0 | 5,000,000 |
| 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 | | | | |
| 10.11 | | | | |
| 15 | TOTAL Debits to Retained Earnings (Acct. 439) | | | |
| 16 | Balance Transferred from Income (Account 433 less Account 418.1) | | 200,057,852 | 178,603,995 |
| 17 | Appropriations of Retained Earnings (Acct. 436) | | | |
| 17.1 | Excess Earnings | | (2,669,912) | (2,537,300) |
| 17.2 | | | | |
| 17.3 | | | | |
| 17.4 | | | | |
| 22 | TOTAL Appropriations of Retained Earnings (Acct. 436) | | (2,669,912) | (2,537,300) |
| 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 | | (159,242,728) | (150,693,583) |
| 30.2 | | | | |
| 30.3 | | | | |
| 30.4 | | | | |
| 30.5 | | | | |
| 36 | TOTAL Dividends Declared-Common Stock (Acct. 438) | | (159,242,728) | (150,693,583) |
| 37 | Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings | | 845,479 | 572,872 |

| | | | | |
|---|---|---|---|---|
| 38 | Balance - End of Period (Total 1,9,15,16,22,29,36,37) | | 811,258,165 | 772,267,474 |
| 39 | APPROPRIATED RETAINED EARNINGS (Account 215) | | | |
| 39.1 | Appropriated Retained Earnings | | 62,100,900 | 59,430,989 |
| 39.2 | | | | |
| 39.3 | | | | |
| 39.4 | | | | |
| 39.5 | | | | |
| 39.6 | | | | |
| 45 | TOTAL Appropriated Retained Earnings (Account 215) | | 62,100,900 | 59,430,989 |
| | 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) | | 62,100,900 | 59,430,989 |
| 48 | TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1) | | 873,359,065 | 831,698,463 |
| | UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly) | | | |
| 49 | Balance-Beginning of Year (Debit or Credit) | | 39,097,599 | 43,138,900 |
| 50 | Equity in Earnings for Year (Credit) (Account 418.1) | | (7,141,006) | 1,531,571 |
| 51 | (Less) Dividends Received (Debit) | | | 5,000,000 |
| 52 | TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year | | (845,479) | (572,872) |
| 52.1 | Corporate Costs Allocated to Subsidiaries | | (845,479) | (572,872) |
| 53 | Balance-End of Year (Total lines 49 thru 52) | | 31,111,114 | 39,097,599 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## STATEMENT OF CASH FLOWS

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

| Line No. | Description (See Instructions No.1 for explanation of codes) (a) | Current Year to Date Quarter/Year (b) | Previous Year to Date Quarter/Year (c) |
|---|---|---|---|
| 1 | Net Cash Flow from Operating Activities | | |
| 2 | Net Income (Line 78(c) on page 117) | 192,916,846 | 180,135,566 |
| 3 | Noncash Charges (Credits) to Income: | | |
| 4 | Depreciation and Depletion | 282,875,101 | 264,151,330 |
| 5 | Amortization of (Specify) (footnote details) | | |
| 5.1 | Amortization of Deferred Power and Natural Gas Costs | (54,040,822) | 104,279,052 |
| 5.2 | Amortization of Debt Expense | 2,034,721 | 2,024,163 |
| 5.3 | Amortization of Investment in Exchange Power | | |
| 8 | Deferred Income Taxes (Net) | 4,398,663 | (3,581,603) |
| 9 | Investment Tax Credit Adjustment (Net) | (821,101) | (135,343) |
| 10 | Net (Increase) Decrease in Receivables | (29,535,130) | (376,114) |
| 11 | Net (Increase) Decrease in Inventory | 21,960,942 | (17,719,292) |
| 12 | Net (Increase) Decrease in Allowances and Environmental Credits Inventory | (3,805,844) | 9,815,601 |
| 13 | Net Increase (Decrease) in Payables and Accrued Expenses | [a]39,842,213 | [d](3,490,756) |
| 14 | Net (Increase) Decrease in Other Regulatory Assets | (6,336,115) | (47,639,430) |
| 15 | Net Increase (Decrease) in Other Regulatory Liabilities | 5,196,553 | (7,394,628) |
| 16 | (Less) Allowance for Other Funds Used During Construction | 10,503,541 | 8,294,329 |
| 17 | (Less) Undistributed Earnings from Subsidiary Companies | (7,141,006) | 1,531,571 |
| 18 | Other (provide details in footnote): | | |
| 18.1 | Cash Received for Settlement of Interest Rate Swaps | 1,104,000 | 4,397,000 |
| 18.2 | Other (provide details in footnote): | [b](4,102,897) | [e]39,582,709 |
| 18.3 | Allowance for Doubtful Accounts | 6,674,943 | 7,250,703 |
| 18.4 | Changes in Other Non-Current Assets and Liabilities | 4,834,418 | 646,854 |
| 18.5 | Cash Paid for Settlement of Interest Rate Swaps | | 0 |
| 22 | Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21) | 459,833,956 | 522,119,912 |
| 24 | Cash Flows from Investment Activities: | | |
| 25 | Construction and Acquisition of Plant (including land): | | |
| 26 | Gross Additions to Utility Plant (less nuclear fuel) | (558,409,435) | [f](518,461,489) |
| 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) | (558,409,435) | (518,461,489) |
| 36 | Acquisition of Other Noncurrent Assets (d) | | |
| 37 | Proceeds from Disposal of Noncurrent Assets (d) | 72,932 | 2,047,651 |
| 39 | Investments in and Advances to Assoc. and Subsidiary Companies | | (7,709,499) |
| 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 | 5,014,387 | |
| 44 | Purchase of Investment Securities (a) | | |
| 45 | Proceeds from Sales of Investment Securities (a) | | |
| 46 | Loans Made or Purchased | | |
| 47 | Collections on Loans | | |
| 49 | Net (Increase) Decrease in Receivables | | |
| 50 | Net (Increase) Decrease in Inventory | | |
| 51 | Net (Increase) Decrease in Allowances and Environmental Credits Held for Speculation | | |
| 52 | Net Increase (Decrease) in Payables and Accrued Expenses | | |
| 53 | Other (provide details in footnote): | | |
| 53.1 | Other | 2,845,791 | 815,210 |
| 53.2 | Dividends Received from Subsidiaries | | 5,000,000 |
| 57 | Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55) | (550,476,325) | (518,308,127) |
| 59 | Cash Flows from Financing Activities: | | |

| | | | |
|---|---|---|---|
| 60 | Proceeds from Issuance of: | | |
| 61 | Long-Term Debt (b) | 120,000,000 | 83,700,000 |
| 62 | Preferred Stock | | |
| 63 | Common Stock | 78,162,826 | 67,725,000 |
| 64 | Other (provide details in footnote): | | |
| 66 | Net Increase in Short-Term Debt (c) | 43,000,000 | |
| 67 | Other (provide details in footnote): | | |
| 70 | Cash Provided by Outside Sources (Total 61 thru 69) | 241,162,826 | 151,425,000 |
| 72 | Payments for Retirement of: | | |
| 73 | Long-term Debt (b) | | |
| 74 | Preferred Stock | | |
| 75 | Common Stock | | |
| 76 | Other (provide details in footnote): | | |
| 76.1 | Debt Issuance Costs | (1,447,241) | (1,156,533) |
| 76.2 | Minimum Tax Witholdings | [(c)](1,740,744) | [(g)](1,585,004) |
| 78 | Net Decrease in Short-Term Debt (c) | | (7,000,000) |
| 80 | Dividends on Preferred Stock | | |
| 81 | Dividends on Common Stock | (159,303,887) | (150,329,156) |
| 83 | Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81) | 78,670,954 | (8,645,693) |
| 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) | (11,971,415) | (4,833,908) |
| 88 | Cash and Cash Equivalents at Beginning of Period | 23,758,997 | 28,592,905 |
| 90 | Cash and Cash Equivalents at End of Period | 11,787,582 | 23,758,997 |

FOOTNOTE DATA

(a) Concept: NetIncreaseDecreaseInPayablesAndAccruedExpensesOperatingActivities

Cash paid (received) during the period for:

Interest: $135,717,213

(b) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Power and natural gas deferrals 162,276; Change in special deposits 12,347,045; Change in other current assets (22,319,768); Non-cash stock compensation 9,323,210; loss on sale of property and equipment 196,893; Other (3,812,553).

(c) Concept: OtherRetirementsOfBalancesImpactingCashFlowsFromFinancingActivities

Payment of minimum tax withholdings for share-based payment awards

(d) Concept: NetIncreaseDecreaseInPayablesAndAccruedExpensesOperatingActivities

Cash paid (received) during the period for:

Income taxes: $7,555,015

Interest: $135,301,539

(e) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Power and natural gas deferrals (2,094,117); Change in special deposits 18,067,069; Change in other current assets 20,326,234; Non-cash stock compensation 9,195,907; gain on sale of property and equipment (1,975,266); Other (3,937,118).

(f) Concept: GrossAdditionsToUtilityPlantLessNuclearFuelInvestingActivities

Additions to PPE in Accounts Payable: $22,779,844

(g) Concept: OtherRetirementsOfBalancesImpactingCashFlowsFromFinancingActivities

Payment of minimum tax withholdings for share-based payment awards

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

**NOTES TO FINANCIAL STATEMENTS**

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

**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 Energy 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 System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (GAAP). As required by the FERC, the Company accounts for its investment in majority owned subsidiaries as required by 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 GAAP in the presentation of (1) current portion of long-term debt, (2) assets and liabilities for cost of removal 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, (10) emissions allowance inventory and liabilities, (11) leases, and (12) implementation costs for software as a service (SAAS).

***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,
- obligations under the Climate Commitment Act (CCA),
- 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:

| | 2025 | 2024 | 2023 |
|---|---|---|---|
| Avista Corp. | 3.52% | 3.45% | 3.52% |

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

| | |
|---|---|
| Electric thermal/other production | 20 |
| Hydroelectric production | 80 |
| Electric transmission | 43 |
| Electric distribution | 41 |
| Natural gas distribution property | 43 |
| 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 Washington Utilities and Transportation Commission (WUTC) and the Idaho Public Utilities Commission (IPUC) have authorized Avista Corp. to calculate AFUDC using its allowed rate of return on rate base. 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:

| | 2025 | 2024 |
|---|---|---|
| Avista Corp. | 7.32% | 7.03% |

***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 date of the enactment 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 in 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 2025 or 2024. 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 millions):

| | 2025 | 2024 |
|---|---|---|
| Stock-based compensation expense | $ 8 | $ 8 |
| Income tax benefits | 2 | 2 |

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:

| | 2025 | 2024 |
|---|---|---|
| **Restricted Shares** | | |
| Shares granted during the year | 141,618 | 82,433 |
| Shares vested during the year | 96,214 | 75,107 |
| Unvested shares at end of year | 190,979 | 158,464 |
| Unrecognized compensation expense at end of year (in millions) | $ 4 | $ 3 |
| **TSR Awards** | | |
| TSR shares granted during the year | 36,616 | 45,739 |
| TSR shares vested during the year | 28,760 | 64,640 |
| TSR shares earned based on market metrics | -- | 35,552 |
| Unvested TSR shares at end of year | 72,574 | 77,530 |
| Unrecognized compensation expense at end of year (in millions) | $ 1 | $ 2 |
| **CEPS Awards** | | |
| CEPS shares granted during the year | 129,056 | 137,161 |
| CEPS shares vested during the year | 86,227 | 64,640 |
| CEPS shares earned based on performance metrics | 34,491 | 29,088 |
| Unvested CEPS shares at end of year | 236,873 | 232,486 |
| Unrecognized compensation expense at end of year (in millions) | $ 7 | $ 3 |

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, 2025 and 2024, the Company had recognized a liability of $2 million and $3 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.

***Accounts Receivable and 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.

The Company has received grants from various government agencies to assist customers with their energy bills. The Company received these grant funds and applied them to customer accounts, reducing accounts receivable balances. These grants totaled $10 million in 2024. There were no grants received under these programs in 2025.

***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 WUTC and the 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 transactions, 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 impact on the income statement. 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 agreements with a variety of entities allowing for cross-commodity netting of derivative agreements with the same counterparty (e.g. power derivatives can be netted with natural gas derivatives under certain conditions). In addition, some master 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 millions):

| | 2025 | 2024 |
|---|---|---|
| Appropriated retained earnings | $ 62 | $ 59 |

***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, 2025, 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 millions):

| | 2025 | 2024 |
|---|---|---|
| Avista Capital | $ (13) | $ (6) |
| AERC | 6 | 8 |
| Total equity in earnings of subsidiary companies | $ (7) | $ 2 |

***Subsequent Events***

Management has evaluated the impact on its financial statements of events occurring after December 31, 2025 up to February 24, 2026, the date that Avista Corp.'s GAAP financial statements were issued and has updated such evaluation for disclosure purposes through the date of this filing on April 17, 2026. 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 recorded 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 millions):

| | 2025 | 2024 |
|---|---|---|
| Unbilled accounts receivable | $ 82 | $ 72 |

*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 a specified period of time, consistent with the discussion of rate regulated sales above.

***Alternative Revenue Programs (Decoupling)***

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, which includes rent, sales of materials, late fees and other charges, are not considered revenues from contracts with customers. This revenue is not so considered, since it is not received pursuant to contracts under which customers 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 millions):

| | 2025 | 2024 |
|---|---|---|
| Utility-related taxes | $ 82 | $ 81 |

**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, 2025, the Company estimates it had unsatisfied capacity performance obligations of $25 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 include 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 69 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.

The Company has entered into a PPA agreement with Rathdrum Power, LLC for the output of the Lancaster Plant through 2041. The PPA meets the accounting definition of a lease. However, since all payments are variable in nature, based on capacity, usage, or performance of the plant, 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 on the Balance Sheets. Total short-term lease costs for 2025 are immaterial.

*Operating Lease Balances in the Financial Statements*

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

| | 2025 | 2024 | 2023 |
|---|---|---|---|
| Operating lease cost: | | | |
| Fixed lease cost (Other operating expenses) | $ 5 | $ 5 | $ 5 |
| Variable lease cost (Other operating expenses and Resource costs) | 31 | 31 | 25 |
| Total operating lease cost | $ 36 | $ 36 | $ 30 |

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

| | 2025 | 2024 |
|---|---|---|
| Cash paid for amounts included in the measurement of lease liabilities: | | |
| Operating cash outflows: | | |
| Operating lease payments | $ 5 | $ 5 |

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

| | December 31, 2025 | December 31, 2024 |
|---|---|---|
| **Operating Leases** | | |
| Operating lease ROU assets | $ 64 | $ 66 |
| Other current liabilities | $ 5 | $ 4 |
| Other non-current liabilities and deferred credits | 60 | 62 |
| Total operating lease liabilities | $ 65 | $ 66 |
| **Weighted Average Remaining Lease Term** | | |
| Operating leases | 20 years | 21 years |
| **Weighted Average Discount Rate** | | |
| Operating leases | 4.32% | 4.30% |

Maturities of lease liabilities (including principal and interest) were as follows as of December 31, 2025 (dollars in millions):

| | Operating Leases |
|---|---|
| 2026 | $ 5 |
| 2027 | 5 |
| 2028 | 5 |
| 2029 | 5 |
| 2030 | 5 |
| Thereafter | 75 |
| Total lease payments | $ 100 |
| Less: imputed interest | (35) |
| Total | $ 65 |

**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 commodity derivative instruments. Avista Corp. utilizes instruments that meet the definition of a derivative under U.S. GAAP, such as forwards, futures, swaps 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, 2025 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 |
| 2026 | 6 | -- | 30,523 | 30,535 | 373 | 328 | 2,325 | 543 |
| 2027 | -- | -- | 14,558 | 14,443 | -- | -- | 1,393 | -- |
| 2028 | -- | -- | 4,413 | 5,393 | -- | -- | 1,013 | -- |

As of December 31, 2025, there are no energy commodity derivative contracts outstanding with expected deliveries after 2028.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2024 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 |
| 2025 | 7 | -- | 27,993 | 39,483 | 427 | 420 | 1,897 | 1,963 |
| 2026 | -- | -- | 17,560 | 13,175 | -- | -- | -- | -- |
| 2027 | -- | -- | 7,555 | 2,250 | -- | -- | -- | -- |

As of December 31, 2024, there were no energy commodity derivative contracts outstanding with expected deliveries after 2027.

(1) Physical transactions represent commodity derivative transactions in which Avista Corp. will take or make delivery of either electricity or natural gas; financial transactions represent financial derivative instruments that are settled in cash with no physical delivery of the underlying commodity, such as futures, swaps, or options 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 millions):

| | 2025 | 2024 |
|---|---|---|
| Number of contracts | 26 | 22 |
| Notional amount (in United States dollars) | $ 6 | $ 2 |
| Notional amount (in Canadian dollars) | 4 | 2 |

***Summary of Outstanding Derivative Instruments***

The amounts recorded on the Balance Sheets as of December 31, 2025 and December 31, 2024 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 energy commodity derivative instruments recorded on the Balance Sheets as of December 31, 2025 (dollars in millions):

| | Fair Value | | | |
|---|---|---|---|---|
| Derivative and Balance Sheet Location | Gross Asset | Gross Liability | Collateral Netting | Net Asset (Liability) on Balance Sheet |
| Derivative instrument assets current | $ 8 | $ -- | $ -- | $ 8 |
| Derivative instrument liabilities current | 7 | (33) | 8 | (18) |
| Long-term portion of derivative liabilities | 2 | (14) | 2 | (10) |
| Total derivative instruments recorded on the balance sheet | $ 17 | $ (47) | $ 10 | $ (20) |

The following table presents the fair values and locations of derivative instruments recorded on the Balance Sheets as of December 31, 2024 (dollars in millions):

| | Fair Value | | | |
|---|---|---|---|---|
| Derivative and Balance Sheet Location | Gross Asset | Gross Liability | Collateral Netting | Net Asset (Liability) on Balance Sheet |
| **Interest rate swap derivatives** | | | | |
| Derivative instrument assets current | $ 1 | $ -- | $ -- | $ 1 |
| **Energy commodity derivatives** | | | | |
| Derivative instrument assets current | 10 | -- | -- | 10 |
| Derivative instrument liabilities current | 11 | (48) | 23 | (14) |
| Long-term portion of derivative liabilities | 2 | (16) | 1 | (13) |
| Total derivative instruments recorded on the balance sheet | $ 24 | $ (64) | $ 24 | $ (16) |

***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, or, in some cases, if the counterparty has reasonable grounds to believe that there has been a material change in Avista Corp.'s creditworthiness, additional collateral may be required. In periods of price volatility, the level of exposure can change significantly. In addition, these contracts contain customary events of default (including cross-defaults to indebtedness and other obligations) and termination provisions. 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 energy commodity derivative instruments as of December 31 (dollars in millions):

| | 2025 | 2024 |
|---|---|---|
| Cash collateral posted | $ 12 | $ 24 |
| Letters of credit outstanding | 14 | 12 |

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 energy commodity 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 millions):

| | 2025 |
|---|---|
| Liabilities with credit-risk-related contingent features | $ 20 |
| Additional collateral to post | 20 |

**NOTE 5. JOINTLY OWNED ELECTRIC FACILITIES**

The Company had a 15 percent ownership interest in Units 3 and 4 of Colstrip, and provided financing for its ownership interest in the project. Effective January 1, 2026, the Company transferred its ownership to NorthWestern. The Company has retained responsibility for remediation obligations in existence at the time the transaction closed. See further discussion of the transaction within Note 15.

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 millions):

| | 2025 | 2024 |
|---|---|---|
| Utility plant in service | $ 401 | $ 401 |
| Accumulated depreciation | (382) | (355) |

The Company retained ownership of certain transmission assets subsequent to transferring its ownership interest in Units 3 and 4 to NorthWestern, which are included in amounts above. In addition, the Company has reclassified certain amounts to be recovered or returned to customers subsequent to the ownership transfer to regulatory assets and liabilities as of December 31, 2025.

See Note 6 for further discussion of AROs.

While the obligations and liabilities with respect to Colstrip have been 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).

**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.

The Company transferred its ownership interest in Colstrip to NorthWestern on January 1, 2026. The Company retained responsibility for its share of the liabilities giving rise to the Colstrip AROs existing as of the transfer date.

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.

In April 2024 and January 2025, the EPA issued additional final rules building on the 2015 regulations and regulating CCR management units at active and inactive power plants. The Colstrip owners are performing analyses to determine whether any potential changes to the existing remediation efforts are required. Based on the results of these analyses to date, the Company believes there will not be a material change to the asset retirement obligation for Colstrip related to these final rules.

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 millions):

| | 2025 | 2024 | 2023 |
|---|---|---|---|
| Asset retirement obligation at beginning of year | $ 18 | $ 18 | $ 16 |
| Liabilities incurred | -- | -- | 2 |
| Liabilities settled | (3) | (1) | -- |
| Accretion expense | 1 | 1 | -- |
| Asset retirement obligation at end of year | $ 16 | $ 18 | $ 18 |

**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 million in cash each year to the pension plan in 2025 and2024. The Company expects to contribute $10 million in cash to the pension plan in 2026.

In 2024, the Company offered pension participants an election to leave the pension plan for an alternative defined contribution 401(k) plan. In April 2024, it was determined that due to the number of participants electing to leave the pension plan, as well as the resulting decrease in expected future service, this event resulted in a curtailment of the pension plan, and an associated gain of $1 million for the reduction in the benefit obligation. This gain was offset against the unrecognized net actuarial loss (and recorded within a regulatory asset). The curtailment triggered a remeasurement of pension plan. The remeasurement did not have a material impact on the Company's financial condition or results of operations.

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 millions):

| | 2026 | 2027 | 2028 | 2029 | 2030 | Total 2031-2035 |
|---|---|---|---|---|---|---|
| Expected benefit payments | $ 46 | $ 46 | $ 47 | $ 47 | $ 48 | $ 249 |

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 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 millions):

| | 2026 | 2027 | 2028 | 2029 | 2030 | Total 2031-2035 |
|---|---|---|---|---|---|---|
| Expected benefit payments | $ 6 | $ 6 | $ 7 | $ 7 | $ 7 | $ 38 |

The Company expects to contribute $6 million to other postretirement benefit plans in 2026. The Company uses a December 31 measurement date for its pension and other postretirement benefit plans.

The following tables set forth the pension and other postretirement benefit plan disclosures as of December 31, 2025 and 2024 and the components of net periodic benefit costs for the years ended December 31, 2025 and 2024 (dollars in millions):

| | Pension Benefits | | Other Post-retirement Benefits | |
|---|---|---|---|---|
| | 2025 | 2024 | 2025 | 2024 |
| **Change in benefit obligation:** | | | | |
| Benefit obligation as of beginning of year | $ 600 | $ 585 | $ 117 | $ 122 |
| Service cost | 16 | 16 | 2 | 3 |
| Interest cost | 35 | 34 | 7 | 7 |
| Actuarial (gain)/loss (1) | 15 | 2 | (3) | (9) |
| Plan change | -- | -- | 1 | -- |
| Benefits paid | (44) | (36) | (8) | (6) |
| Curtailments | -- | (1) | -- | -- |
| Benefit obligation as of end of year (2) | $ 622 | $ 600 | $ 116 | $ 117 |
| **Change in plan assets:** | | | | |
| Fair value of plan assets as of beginning of year | $ 608 | $ 590 | $ 67 | $ 58 |
| Actual return on plan assets | 80 | 42 | 8 | 9 |
| Employer contributions | 10 | 10 | -- | -- |
| Benefits paid | (42) | (34) | -- | -- |
| Fair value of plan assets as of end of year (2) | $ 656 | $ 608 | $ 75 | $ 67 |
| Funded status | $ 34 | $ 8 | $ (41) | $ (50) |
| **Amounts recognized in the Balance Sheets:** | | | | |
| Non-current assets | $ 61 | $ 35 | $ -- | $ -- |
| Current liabilities | (2) | (2) | (1) | (1) |
| Non-current liabilities | (25) | (25) | (40) | (49) |
| Net amount recognized | $ 34 | $ 8 | $ (41) | $ (50) |
| Accumulated pension benefit obligation (2) | $ 535 | $ 522 | | |
| Accumulated postretirement benefit obligation: | | | | |
| For retirees | | | $ 64 | $ 67 |
| For fully eligible employees | | | $ 18 | $ 16 |
| For other participants | | | $ 34 | $ 34 |
| **Included in accumulated other comprehensive loss (income) (net of tax):** | | | | |
| Unrecognized prior service cost | $ 3 | $ 3 | $ 1 | $ -- |
| Unrecognized net actuarial loss (gain) | 52 | 70 | (4) | 2 |
| Total | 55 | 73 | (3) | 2 |
| Less regulatory asset | (54) | (73) | 3 | (2) |
| Accumulated other comprehensive loss for unfunded benefit obligation for pensions and other postretirement benefit plans | $ 1 | $ -- | $ -- | $ -- |

(1) The change in the pension benefit obligation related to actuarial loss is primarily related to actual investment returns differing from our assumptions, partially offset by financial and demographic assumption changes.

(2) As of December 31, 2025, the SERP had a projected benefit obligation of $27 million and an accumulated benefit obligation of $25 million, with no plan assets.

| | Pension Benefits | | Other Post-retirement Benefits | |
|---|---|---|---|---|
| | 2025 | 2024 | 2025 | 2024 |
| **Weighted-average assumptions as of December 31:** | | | | |
| Discount rate for benefit obligation | 5.96% | 6.13% | 6.11% | 6.09% |
| Discount rate for annual expense | 6.13% | 5.86% | 6.09% | 5.83% |
| Expected long-term return on plan assets | 7.40% | 7.80% | 6.60% | 6.70% |
| Rate of compensation increase | 5.07% | 5.19% | | |
| Medical cost trend pre-age 65 - initial | | | 7.00% | 6.50% |
| Medical cost trend pre-age 65 - ultimate | | | 5.00% | 5.00% |
| Ultimate medical cost trend year pre-age 65 | | | 2034 | 2031 |
| Medical cost trend post-age 65 - initial | | | 7.00% | 6.50% |
| Medical cost trend post-age 65 - ultimate | | | 5.00% | 5.00% |
| Ultimate medical cost trend year post-age 65 | | | 2034 | 2031 |

| | Pension Benefits | | Other Post-retirement Benefits | |
|---|---|---|---|---|
| | 2025 | 2024 | 2025 | 2024 |
| **Components of net periodic benefit cost:** | | | | |
| Service cost (1) | $ 16 | $ 16 | $ 2 | $ 3 |
| Interest cost | 35 | 34 | 7 | 7 |
| Expected return on plan assets | (44) | (45) | (4) | (4) |
| Amortization of prior service cost (credit) | 1 | -- | -- | (1) |
| Net loss recognition | 3 | 2 | -- | -- |
| Net periodic benefit cost | $ 11 | $ 7 | $ 5 | $ 5 |

(1) Total service cost in the table above is 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 45 percent of all labor and benefits is capitalized to utility property and 55 percent is expensed to utility other operating expenses.

Pension costs other than service costs are presented in the Statements of Income in the line item "Other income-net."

***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 of 55 percent in equity securities, 40 percent in debt securities, and 5 percent in real estate. The target investment allocation percentages are typically the midpoint of the established range.

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, 2025 at fair value (dollars in millions):

| | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| Cash equivalents | $ -- | $ 9 | $ -- | $ 9 |
| Fixed income securities: | | | | |
| U.S. government issues | -- | 47 | -- | 47 |
| Corporate issues | -- | 227 | -- | 227 |
| International issues | -- | 35 | -- | 35 |
| Municipal issues | -- | 9 | -- | 9 |
| Mutual funds: | | | | |
| U.S. equity securities | 162 | -- | -- | 162 |
| International equity securities | 64 | -- | -- | 64 |
| **Plan assets measured at NAV (not subject to hierarchy disclosure)** | | | | |
| Common/collective trusts: real estate | -- | -- | -- | 24 |
| Partnership/closely held investments: | | | | |
| International equity securities | -- | -- | -- | 73 |
| Real estate | -- | -- | -- | 6 |
| Total | $ 226 | $ 327 | $ -- | $ 656 |

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, 2024 at fair value (dollars in millions):

| | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| Cash equivalents | $ -- | $ 8 | $ -- | $ 8 |
| Fixed income securities: | | | | |
| U.S. government issues | -- | 37 | -- | 37 |
| Corporate issues | -- | 213 | -- | 213 |
| International issues | -- | 33 | -- | 33 |
| Municipal issues | -- | 11 | -- | 11 |
| Mutual funds: | | | | |
| U.S. equity securities | 160 | -- | -- | 160 |
| International equity securities | 63 | -- | -- | 63 |
| **Plan assets measured at NAV (not subject to hierarchy disclosure)** | | | | |
| Common/collective trusts: real estate | -- | -- | -- | 24 |
| Partnership/closely held investments: | | | | |
| International equity securities | -- | -- | -- | 52 |
| Real estate | -- | -- | -- | 7 |
| Total | $ 223 | $ 302 | $ -- | $ 608 |

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 2025 and 2024.

The fair value of other postretirement plan assets was determined to be $75 million as of December 31, 2025 and $67 million as of December 31, 2024. 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 18 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 millions):

| | 2025 | 2024 | 2023 |
|---|---|---|---|
| Employer 401(k) matching contributions | $ 18 | $ 16 | $ 15 |

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 and corresponding deferred compensation liabilities on the Balance Sheets of the following amounts as of December 31 (dollars in millions):

| | 2025 | 2024 |
|---|---|---|
| Deferred compensation assets and liabilities | $ 9 | $ 9 |

**NOTE 8. ACCOUNTING FOR INCOME TAXES**

***Income Tax Expense***

A reconciliation of federal income taxes derived from the statutory federal tax rate of 21 percent applied to income before income taxes is as follows for the years ended December 31 (dollars in millions):

| | 2025 | | 2024 | |
|---|---|---|---|---|
| Income from continuing operations before income tax expense (benefit) | $ 225 | N/A | $ 180 | N/A |
| U.S. federal statutory tax rate | 47 | 21.0% | 38 | 21.0% |
| State income taxes, net of federal income tax effect (1) | 1 | 0.4 | 1 | 0.5 |
| Research and development tax credits | (1) | (0.4) | (1) | (0.6) |
| Other adjustments: | | | | |
| Flow through related to deduction of meters and mixed service costs (2) | (7) | (3.1) | (23) | (12.6) |
| Excess deferred tax amortization | (11) | (5.0) | (11) | (6.0) |
| CARES Act tax benefit amortization | (2) | (0.9) | (1) | (0.6) |
| Other | (2) | (0.9) | (2) | (0.9) |
| Total other adjustments | (22) | (9.9) | (37) | (20.1) |
| Effective tax rate | $ 25 | 11.1% | $ 1 | 0.8% |

(1) State taxes in Oregon made up greater than 50 percent of the tax effect in this category.

(2) The Company's general rate cases included approval of base rate increases, offset by tax customer credits. As the tax customer credits are returned to customers, this results in a decrease to income tax expense due to flowing through the benefits related to meters and mixed service costs. Once these tax customer credits have been applied to customers and are exhausted, income tax expense will increase.

In July 2025, OBBB was signed into law, which includes significant changes to the U.S. tax code and related laws. The Company has evaluated the potential impact of OBBB on our financial statements in accordance with ASC 740 and, as of December 31, 2025, has determined the impact to the effective tax rate is not material.

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, 2025, the Company had $22 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 $14 million of the state tax credits. As such, the Company has recorded a valuation allowance of $8 million against the state tax credit carryforwards and reflected the net amount of $14 million as an asset as of December 31, 2025. State tax credits expire from 2026 to 2039.

***Uncertain Tax Positions***

The Company recognizes tax positions that meet the more-likely-than-not threshold as the largest amount of the tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a tax authority that has full knowledge of all relevant information. The change in unrecognized tax benefits is as follows (dollars in millions):

| | 2025 | 2024 |
|---|---|---|
| Unrecognized tax benefits at January 1 | $ 1 | $ -- |
| Gross increases - tax positions in prior period | 2 | -- |
| Gross increases - tax positions in current period | 1 | 1 |
| Unrecognized tax benefits at December 31 | $ 4 | $ 1 |

The Company's unrecognized tax benefits include approximately $1 million related to tax positions as of December 31, 2025 and 2024 that, if recognized, would impact the annual effective tax rate.

***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 2021 are open for an IRS tax examination.

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 2021 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 various agreements for the purchase or exchange of electric energy (including transmission), as well as contracts for the purchase of natural gas for resale and fuel for thermal generation (including transportation). The remaining term of the contracts ranges from one month to twenty-five years.

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

| | 2025 | 2024 | 2023 |
|---|---|---|---|
| Power and natural gas resources | $ 520 | $ 548 | $ 607 |

The following table details Avista Corp.'s future fixed contractual commitments for power and natural gas resources (dollars in millions):

The following table details Avista Corp.'s future fixed contractual commitments for power and natural gas resources (dollars in millions):

| | 2026 | 2027 | 2028 | 2029 | 2030 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Power resources | $ 335 | $ 268 | $ 249 | $ 234 | $ 230 | $ 2,509 | $ 3,825 |
| Natural gas resources | 106 | 77 | 142 | 48 | 43 | 156 | 572 |
| Total | $ 441 | $ 345 | $ 391 | $ 282 | $ 273 | $ 2,665 | $ 4,397 |

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 the Company has no investment in the PUD generating facilities, the contracts obligate the Company to pay certain minimum amounts whether or not the facilities are operating. The cost of power purchased 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 amounts in respect of the PUDs' existing debt service cost. The fixed minimum amounts payable by the Company under each contract with a PUD includes an amount that is the same percentage of the PUD's total debt service requirements on its revenue bonds issued to finance the related generating facility as the Company's percentage entitlement to the output of that facility. The total portion of the PUDs' future debt service requirements so allocable to the Company as of December 31, 2025 (principal and interest) was $264 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 in other operating expenses in the Statements of Income. The following table details future contractual commitments under these agreements (dollars in millions):

| | 2026 | 2027 | 2028 | 2029 | 2030 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Contractual obligations | $ 19 | $ 20 | $ 20 | $ 21 | $ 21 | $ 163 | $ 264 |

**NOTE 10. NOTES PAYABLE**

*Lines of Credit*

Avista Corp. has a committed line of credit in the total amount of $500 million with an expiration date of June 2029. The Company may request that the lenders extend their commitments for an additional one-year period (subject to customary conditions). 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 on borrowings (excluding letters of credit) under the Company's revolving committed line of credit were as follows as of December 31 (dollars in millions):

| | 2025 | 2024 |
|---|---|---|
| Balance outstanding at end of period | $ 385 | $ 342 |
| Letters of credit balance outstanding at end of period | 5 | 5 |
| Average interest rate at end of period | 4.84% | 5.52% |

As of December 31, 2025 and 2024, the borrowings outstanding under Avista Corp.'s committed lines of credit were classified as short-term borrowings on the Balance Sheets.

*Letter of Credit Facility*

Avista Corp. has a letter of credit agreement in the aggregate amount of $50 million. Either party may terminate the agreement at any time.

The Company had $14 million and $12 million in letters of credit outstanding under this agreement as of December 31, 2025 and December 31, 2024, 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 one case other obligations. The committed line of credit also includes a covenant which does not permit the ratio of "consolidated total debt" to "consolidated total capitalization" of Avista Corp. to be greater than 65 percent at any time. As of December 31, 2025, the Company complied with this covenant.

**NOTE 11. BONDS**

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

| Maturity Year | Description | Interest Rate | 2025 | 2024 |
|---|---|---|---|---|
| **Avista Corp. Secured Long-Term Debt** | | | | |
| 2028 | Secured Medium-Term Notes | 6.37% | $ 25 | $ 25 |
| 2032 | Secured Pollution Control Bonds | 3.88% | 67 | 67 |
| 2034 | Secured Pollution Control Bonds | 3.88% | 17 | 17 |
| 2035 | First Mortgage Bonds | 6.25% | 150 | 150 |
| 2037 | First Mortgage Bonds | 5.70% | 150 | 150 |
| 2040 | First Mortgage Bonds | 5.55% | 35 | 35 |
| 2041 | First Mortgage Bonds | 4.45% | 85 | 85 |
| 2044 | First Mortgage Bonds | 4.11% | 60 | 60 |
| 2045 | First Mortgage Bonds | 4.37% | 100 | 100 |
| 2047 | First Mortgage Bonds | 4.23% | 80 | 80 |
| 2047 | First Mortgage Bonds | 3.91% | 90 | 90 |
| 2048 | First Mortgage Bonds | 4.35% | 375 | 375 |
| 2049 | First Mortgage Bonds | 3.43% | 180 | 180 |
| 2050 | First Mortgage Bonds | 3.07% | 165 | 165 |
| 2051 | First Mortgage Bonds | 3.54% | 175 | 175 |
| 2051 | First Mortgage Bonds | 2.90% | 140 | 140 |
| 2052 | First Mortgage Bonds | 4.00% | 400 | 400 |
| 2053 | First Mortgage Bonds | 5.66% | 250 | 250 |
| 2055 | First Mortgage Bonds (1) | 6.18% | 120 | -- |
| | Total secured long-term debt | | $ 2,664 | $ 2,544 |

(1) In July 2025, the Company issued and sold $120 million of 6.18 percent first mortgage bonds due in 2055 with institutional investors in the private placement market. The net proceeds from the sale of the bonds were used to repay a portion of the borrowings outstanding under the Company's committed line of credit.

(2)

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

| | 2026 | 2027 | 2028 | 2029 | 2030 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Debt maturities | $ -- | $ -- | $ 25 | $ -- | $ -- | $ 2,691 | $ 2,716 |

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, 2025, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.8 billion by Avista Corp. 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 $52 million to Avista Capital II, an affiliated business trust formed by the Company. Avista Capital II issued $50 million of Preferred Trust Securities. The distribution rate on the Preferred Trust Securities is three-month CME Term SOFR plus 1.137 percent.

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

| | 2025 | 2024 | 2023 |
|---|---|---|---|
| Low distribution rate | 4.93% | 5.64% | 5.64% |
| High distribution rate | 5.64% | 6.51% | 6.55% |
| Distribution rate at the end of the year | 4.93% | 5.64% | 6.51% |

Concurrent with the issuance of the Preferred Trust Securities, Avista Capital II issued $2 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 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 as shown on the Balance Sheets are reasonable estimates of their fair values. The carrying values of bonds and advances from associated companies as shown on the Balance Sheets may be different from the estimated fair value. See below for the estimated fair value of bonds and advances from associated companies.

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 include not only 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 millions):

| | 2025 | | 2024 | |
|---|---|---|---|---|
| | Carrying Value | Estimated Fair Value | Carrying Value | Estimated Fair Value |
| Bonds (Level 2) | $ 1,100 | $ 953 | $ 1,100 | $ 938 |
| Bonds (Level 3) | 1,564 | 1,229 | 1,444 | 1,089 |
| Advances from associated companies (Level 3) | 52 | 46 | 52 | 47 |

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 market prices of 58.88 to 108.35 percent of the principal amount, where 100.00 percent 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 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, 2025 at fair value on a recurring basis (dollars in millions):

| | Level 1 | Level 2 | Level 3 | Counterparty and Cash Collateral Netting (1) | Total |
|---|---|---|---|---|---|
| **December 31, 2025** | | | | | |
| **Assets:** | | | | | |
| Energy commodity derivatives | $ -- | $ 17 | $ -- | $ (9) | $ 8 |
| Deferred compensation assets: | | | | | |
| Mutual Funds: | | | | | |
| Fixed income securities | 2 | -- | -- | -- | 2 |
| Equity securities | 7 | -- | -- | -- | 7 |
| Total | $ 9 | $ 17 | $ -- | $ (9) | $ 17 |
| **Liabilities:** | | | | | |
| Energy commodity derivatives (2) | $ -- | $ 37 | $ 10 | $ (19) | $ 28 |
| Total | $ -- | $ 37 | $ 10 | $ (19) | $ 28 |

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, 2024 at fair value on a recurring basis (dollars in millions):

| | Level 1 | Level 2 | Level 3 | Counterparty and Cash Collateral Netting (1) | Total |
|---|---|---|---|---|---|
| **December 31, 2024** | | | | | |
| **Assets:** | | | | | |
| Energy commodity derivatives | $ -- | $ 23 | $ -- | $ (13) | $ 10 |
| Interest rate swap derivatives | -- | 1 | -- | -- | 1 |
| Deferred compensation assets: | | | | | |
| Mutual Funds: | | | | | |
| Fixed income securities | 2 | -- | -- | -- | 2 |
| Equity securities | 7 | -- | -- | -- | 7 |
| Total | $ 9 | $ 24 | $ -- | $ (13) | $ 20 |
| **Liabilities:** | | | | | |
| Energy commodity derivatives (2) | $ -- | $ 61 | $ 3 | $ (37) | $ 27 |
| Total | $ -- | $ 61 | $ 3 | $ (37) | $ 27 |

(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 a natural gas exchange agreement.

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. 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.

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 market 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 currently estimates volumes and timing of transactions based on a most likely scenario using historical data. Historically, the timing and volume of transactions are not 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, 2025 (dollars in millions, except mmBTU amounts):

| | Fair Value (Net) at December 31, 2025 | Valuation Technique | Unobservable Input | Range |
|---|---|---|---|---|
| Natural gas exchange | $ (10) | Internally derived weighted average cost of gas | Forward purchase prices | $1.33 - $3.25/mmBTU<br>$2.46 Weighted Average |
| | | | Forward sales prices | $1.60 - $8.00/mmBTU<br>$4.66 Weighted Average |
| | | | Purchase volumes | 270,000 - 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 and are reviewed on at least a quarterly basis to ensure they provide a reasonable estimate of fair value each reporting period.

There were no transfers into or out of Level 3 fair value measurements during the 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 millions):

| | Natural Gas Exchange Agreement |
|---|---|
| **2025:** | |
| Balance as of January 1, 2025 | $ (3) |
| Total gains or (losses) (realized/unrealized): | |
| Included in regulatory assets | (5) |
| Recognized in net income | (2) |
| Ending balance as of December 31, 2025 | $ (10) |
| **2024:** | |
| Balance as of January 1, 2024 | $ (8) |
| Total gains or (losses) (realized/unrealized): | |
| Included in regulatory assets | 5 |
| Ending balance as of December 31, 2024 | $ (3) |

## 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 Oregon Public Utility Commission (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 40 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, 2025 was $332 million.

The Company has 10 million authorized shares of preferred stock. The Company did not have preferred stock outstanding as of December 31, 2025 and 2024.

***Common Stock Issuances***

The Company issued common stock for total net proceeds of $78 million in 2025. Most of these issuances were made through sales agency agreements under which the Company may offer and sell new shares of common stock from time to time through its sales agents. In 2025, 2.0 million shares were issued under these agreements.

## 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 outcome of any matter because litigation and other contested proceedings are subject to numerous uncertainties. For matters affecting Avista Corp.'s, the Company intends to seek, to the extent appropriate, recovery of costs through the ratemaking process.

***Collective Bargaining Agreements***

The Company's collective bargaining agreement with the IBEW represents 35 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, Idaho and Montana, are covered under a four-year agreement which expires in 2029.

In April 2025, the Company's System Operators voted to unionize, and the National Labor Relations Board certified the IBEW Local 77 as their exclusive collective bargaining representative. We are in the process of negotiating a separate contract with the IBEW for the System Operator group, which is comprised of approximately 20 employees.

***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 million for fire suppression and investigation costs and related expenses incurred in connection with a wildfire (known as the "Boyds Fire") that occurred in Ferry County, Washington, in August 2018. Additional lawsuits were subsequently filed by private landowners seeking $1 million in property damages as well as potential non-economic damages, and holders of insurance subrogation claims seeking recovery of $2 million in insurance proceeds purportedly paid to their insureds.

In June 2025, the Company settled with a single plaintiff which only named the Company as a defendant for less than $0.1 million. Additionally, the Company, along with its independent vegetation management contractors Asplundh Tree Company and CN Utility Consulting, reached agreements to settle all claims included in the remaining lawsuits for $3 million. None of the settlements in these cases were the responsibility of the Company, but rather the responsibility was split between Asplundh Tree Company and CN Utility Consulting.

***Labor Day 2020 Windstorm/Babb Road Fire***

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, including the Babb Road Fire, which occurred near the town of Malden, Washington.

Eleven lawsuits were filed in connection with the Babb Road Fire. CN Utility Consulting, which performs vegetation management services as an independent contractor to the Company, was also named as defendants in each of the lawsuits. The lawsuits included six subrogation actions filed by 51 insurance companies and five actions on behalf of 128 individual plaintiffs.

In April and May 2025, the Company and CN Utility Consulting reached agreements to settle all claims included in the lawsuits. The total settlement paid was $27 million, of which the Company paid $21 million and CN Utility Consulting was responsible for $6 million. An order dismissing all cases was entered by the Court in September 2025. The Company received insurance proceeds for the settlement amounts paid, resulting in no impact on net income.

***Orofino Fire***

In August 2023, a 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. The Company has to date found no evidence suggesting negligence on its part. Except for three minor claims for damage to personal property which were resolved, 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 additional claims are asserted; however, at this time, it is unable to estimate the likelihood of an adverse outcome or the amount or range of a potential loss in the event of an adverse outcome.

***Colstrip***

*Colstrip Owners Arbitration and Litigation*

Prior to January 1, 2026, Colstrip Units 3 and 4 were 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, imposed 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 was that electricity from such resources, including Colstrip, could no longer be delivered to Washington retail customers after 2025.

*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 would transfer its 15 percent ownership in Colstrip Units 3 and 4 to NorthWestern. There was no monetary exchange included in the transaction. The transaction closed at midnight on January 1, 2026.

Under the agreement, the Company was 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) site remediation expenses except certain costs relating to post closing activities. In addition, under the agreement, the Company retained its voting rights with respect to decisions relating to remediation.

The Company retained its interest in the Colstrip transmission line between Colstrip, Montana to Townsend, Montana, which is excluded from the transaction.

*Agreement Between PSE and NorthWestern*

In July 2024, PSE entered into an agreement with NorthWestern under which, PSE will transfer its 25 percent ownership in Colstrip Units 3 and 4 to NorthWestern. There was no monetary exchange included in the transaction. The transaction closed at midnight on January 1, 2026.

*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 alleged the failure to contain coal dust in connection with the operation of Colstrip, and was seeking unspecified damages. In March 2025, the parties reached an agreement to settle all claims in the matter for $1 million, with the majority of that amount being paid through insurance proceeds and the remainder by entities other than the owners of Colstrip.

*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 the 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, and is no longer impacted by the outcome of these proceedings, given its transfer of Colstrip to NorthWestern.

***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 received 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 continues to 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.

***Complaint of Consumers for Independent Regional Transmission Planning for All FERC-Jurisdictional Transmission Facilities at 100kV and Above***

In December 2024, the Company received notice of a complaint filed with the FERC by Consumers for Independent Regional Transmission Planning against all FERC-jurisdictional Transmission providers with local planning tariffs utilizing facilities at 100 kV and above, which includes the Company. The complaint alleges that the local transmission planning process allows individual transmission owners to plan FERC-jurisdictional transmission facilities without regard to whether that planning is the more efficient or cost-effective project for the interconnected grid and cost effective for customers. The Company intends to vigorously defend itself in this action; 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.

***Other Contingencies***

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes any 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 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 $85 million as of December 31, 2025 and $36 million as of December 31, 2024. 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. The Company received approval to recover $32 million of the ERM deferred surcharge balance over a two-year period starting July 1, 2025.

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 liabilities of $5 million as of December 31, 2025 and $15 million as of December 31, 2024. 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 a liability of $33 million as of December 31, 2025 and $25 million as of December 31, 2024. Liability balances 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 December 2026.

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 to 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 will 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. A pending application would extend the mechanism through August 31, 2029.

*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 equity, 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, 2025 and December 31, 2024, the Company had the following cumulative balances outstanding related to decoupling and earnings sharing mechanisms in its various jurisdictions (dollars in millions):

| | December 31, 2025 | | December 31, 2024 | |
|---|---|---|---|---|
| **Washington** | | | | |
| Decoupling surcharge | $ | 31 | $ | 18 |
| Provision for earnings sharing rebate | $ | (4) | $ | -- |
| **Idaho** | | | | |
| Decoupling surcharge | $ | 4 | $ | 1 |
| **Oregon** | | | | |
| Decoupling surcharge | $ | 9 | $ | 1 |

**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, 2025, the Company had a note receivable balance from Avista Capital of $23 million with an applicable interest rate of 6.75 percent.

**NOTE 18. SUBSEQUENT EVENTS**

The Company has evaluated its subsequent events in accordance with the policy disclosed in Note 1 and noted no subsequent events have occurred.

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

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

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

| Line No. | Item (a) | Unrealized Gains and Losses on Available-For-Sale Securities (b) | Minimum Pension Liability Adjustment (net amount) (c) | Foreign Currency Hedges (d) | Other Adjustments (e) | Other Cash Flow Hedges Interest Rate Swaps (f) | Other Cash Flow Hedges [Specify] (g) | Totals for each category of items recorded in Account 219 (h) | Net Income (Carried Forward from Page 116, Line 78) (i) | Total Comprehensive Income (j) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Balance of Account 219 at Beginning of Preceding Year | | (357,109) | | | | | (357,109) | | |
| 2 | Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income | | | | | | | 0 | | |
| 3 | Preceding Quarter/Year to Date Changes in Fair Value | | 712,589 | | | | | 712,589 | | |
| 4 | Total (lines 2 and 3) | 0 | 712,589 | 0 | 0 | 0 | 0 | 712,589 | 180,135,566 | 180,848,155 |
| 5 | Balance of Account 219 at End of Preceding Quarter/Year | 0 | 355,480 | 0 | 0 | 0 | 0 | 355,480 | | |
| 6 | Balance of Account 219 at Beginning of Current Year | 0 | 355,480 | 0 | 0 | 0 | 0 | 355,480 | | |
| 7 | Current Quarter/Year to Date Reclassifications from Account 219 to Net Income | | | | | | | 0 | | |
| 8 | Current Quarter/Year to Date Changes in Fair Value | | (901,922) | | | | | (901,922) | | |
| 9 | Total (lines 7 and 8) | 0 | (901,922) | 0 | 0 | 0 | 0 | (901,922) | 192,916,846 | 192,014,924 |
| 10 | Balance of Account 219 at End of Current Quarter/Year | 0 | (546,442) | 0 | 0 | 0 | 0 | (546,442) | | |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

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

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

| Line No. | Classification (a) | Total Company For the Current Year/Quarter Ended (b) | Electric (c) | Gas (d) | Other (Specify) (e) | Other (Specify) (f) | Other (Specify) (g) | Common (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | UTILITY PLANT | | | | | | | |
| 2 | In Service | | | | | | | |
| 3 | Plant in Service (Classified) | 8,516,904,989 | 5,875,756,090 | 1,858,266,456 | | | | 782,882,443 |
| 4 | Property Under Capital Leases | 64,004,383 | | | | | | 64,004,383 |
| 5 | Plant Purchased or Sold | | | | | | | |
| 6 | Completed Construction not Classified | | | | | | | |
| 7 | Experimental Plant Unclassified | | | | | | | |
| 8 | Total (3 thru 7) | 8,580,909,372 | 5,875,756,090 | 1,858,266,456 | | | | 846,886,826 |
| 9 | Leased to Others | | | | | | | |
| 10 | Held for Future Use | 25,996,598 | 25,996,598 | | | | | |
| 11 | Construction Work in Progress | 283,713,025 | 252,261,201 | 5,248,586 | | | | 26,203,238 |
| 12 | Acquisition Adjustments | 245,568 | 245,568 | | | | | |
| 13 | Total Utility Plant (8 thru 12) | 8,890,864,563 | 6,154,259,457 | 1,863,515,042 | | | | 873,090,064 |
| 14 | Accumulated Provisions for Depreciation, Amortization, & Depletion | 3,132,651,306 | 2,209,846,169 | 581,188,208 | | | | 341,616,929 |
| 15 | Net Utility Plant (13 less 14) | 5,758,213,257 | 3,944,413,288 | 1,282,326,834 | | | | 531,473,135 |
| 16 | DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION | | | | | | | |
| 17 | In Service: | | | | | | | |
| 18 | Depreciation | 2,912,483,559 | 2,184,668,124 | 579,561,754 | | | | 148,253,681 |
| 19 | Amortization and Depletion of Producing Natural Gas Land and Land Rights | | | | | | | |
| 20 | Amortization of Underground Storage Land and Land Rights | | | | | | | |
| 21 | Amortization of Other Utility Plant | 220,167,747 | 25,178,045 | 1,626,454 | | | | 193,363,248 |
| 22 | Total in Service (18 thru 21) | 3,132,651,306 | 2,209,846,169 | 581,188,208 | | | | 341,616,929 |
| 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) | 3,132,651,306 | 2,209,846,169 | 581,188,208 | | | | 341,616,929 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

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

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of the prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date.

| Line No. | Account (a) | Balance Beginning of Year (b) | Additions (c) | Retirements (d) | Adjustments (e) | Transfers (f) | Balance at End of Year (g) |
|---|---|---|---|---|---|---|---|
| 1 | 1. INTANGIBLE PLANT | | | | | | |
| 2 | (301) Organization | | | | | | 0 |
| 3 | (302) Franchise and Consents | 46,991,292 | 91,176 | | | | 47,082,468 |
| 4 | (303) Miscellaneous Intangible Plant | 61,200,270 | 5,655 | | | (49,077,952) | 12,127,973 |
| 5 | TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4) | 108,191,562 | 96,831 | 0 | 0 | (49,077,952) | 59,210,441 |
| 6 | 2. PRODUCTION PLANT | | | | | | |
| 7 | A. Steam Production Plant | | | | | | |
| 8 | (310) Land and Land Rights | 3,857,583 | 211,445 | 3,706,536 | | | 362,492 |
| 9 | (311) Structures and Improvements | 141,789,506 | 6,337,560 | 29,887 | | | 148,097,179 |
| 10 | (312) Boiler Plant Equipment | 226,246,903 | 11,491,556 | 4,540,220 | | | 233,198,239 |
| 11 | (313) Engines and Engine-Driven Generators | 1,227,631 | (1,220,862) | | | | 6,769 |
| 12 | (314) Turbogenerator Units | 59,342,212 | 5,617,544 | 1,221,560 | | | 63,738,196 |
| 13 | (315) Accessory Electric Equipment | 31,769,001 | 2,450,949 | 707,436 | | | 33,512,514 |
| 13.1 | (315.1) Computer Hardware | | | | | | 0 |
| 13.2 | (315.2) Computer Software | | | 49,598 | | 300,053 | 250,455 |
| 13.3 | (315.3) Communication Equipment | | | | | 413,971 | 413,971 |
| 14 | (316) Misc. Power Plant Equipment | 18,508,414 | 152,004 | 111,062 | | | 18,549,356 |
| 15 | (317) Asset Retirement Costs for Steam Production | 17,463,496 | (213,338) | | | | 17,250,158 |
| 16 | TOTAL Steam Production Plant (Enter Total of lines 8 thru 15) | 500,204,746 | 24,826,858 | 10,366,299 | 0 | 714,024 | 515,379,329 |
| 17 | B. Nuclear Production Plant | | | | | | |
| 18 | (320) Land and Land Rights | | | | | | 0 |
| 19 | (321) Structures and Improvements | | | | | | 0 |
| 20 | (322) Reactor Plant Equipment | | | | | | 0 |
| 21 | (323) Turbogenerator Units | | | | | | 0 |
| 22 | (324) Accessory Electric Equipment | | | | | | 0 |
| 22.1 | (324.1) Computer Hardware | | | | | | 0 |
| 22.2 | (324.2) Computer Software | | | | | | 0 |
| 22.3 | (324.3) Communication Equipment | | | | | | 0 |
| 23 | (325) Misc. Power Plant Equipment | | | | | | 0 |
| 24 | (326) Asset Retirement Costs for Nuclear Production | | | | | | 0 |
| 25 | TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24) | 0 | 0 | 0 | 0 | 0 | 0 |
| 26 | C. Hydraulic Production Plant | | | | | | |
| 27 | (330) Land and Land Rights | 68,422,730 | 12,750 | | | | 68,435,480 |
| 28 | (331) Structures and Improvements | 120,154,948 | 5,014,503 | 474,991 | | | 124,694,460 |
| 29 | (332) Reservoirs, Dams, and Waterways | 269,583,106 | 3,184,130 | 203,384 | | | 272,563,852 |
| 30 | (333) Water Wheels, Turbines, and Generators | 236,368,578 | 8,629,577 | 1,883,677 | | | 243,114,478 |
| 31 | (334) Accessory Electric Equipment | 96,167,767 | 20,891,023 | 558,575 | | | 116,500,215 |
| 31.1 | (334.1) Computer Hardware | | 204,164 | (661) | | 12,195 | 217,020 |
| 31.2 | (334.2) Computer Software | | | | | 7,715 | 7,715 |
| 31.3 | (334.3) Communication Equipment | | 115,217 | 122,929 | | 3,627,341 | 3,619,629 |
| 32 | (335) Misc. Power Plant Equipment | 14,660,064 | 461,508 | 95,353 | | | 15,026,219 |
| 33 | (336) Roads, Railroads, and Bridges | 3,920,845 | | | | | 3,920,845 |
| 34 | (337) Asset Retirement Costs for Hydraulic Production | | | | | | 0 |
| 35 | TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34) | 809,278,038 | 38,512,872 | 3,338,248 | 0 | 3,647,251 | 848,099,913 |
| 35.1 | D. Solar Production Plant | | | | | | |
| 35.2 | (338.1) Land and Land Rights | | | | | | 0 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 35.3 | (338.2) Structures and Improvements | | | | | | 0 |
| 35.5 | (338.4) Solar Panels | | | | | | 0 |
| 35.6 | (338.5) Collector System | | | | | | 0 |
| 35.7 | (338.6) Generator Step-up Transformers (GSU) | | | | | | 0 |
| 35.8 | (338.7) Inverters | | | | | | 0 |
| 35.9 | (338.8) Other Accessory Electrical Equipment | | | | | | 0 |
| 35.10 | (338.9) Computer Hardware | | | | | | 0 |
| 35.11 | (338.10) Computer Software | | | | | | 0 |
| 35.12 | (338.11) Communication Equipment | | | | | | 0 |
| 35.13 | (338.12) Miscellaneous Power Plant Equipment | | | | | | 0 |
| 35.14 | (338.13) Asset Retirement Costs for Solar Production | | | | | | 0 |
| 35.15 | TOTAL Solar Production Plant (Enter Total of lines 35.2 thru 35.14) | 0 | 0 | 0 | 0 | 0 | 0 |
| 35.16 | E. Wind Production Plant | | | | | | |
| 35.17 | (338.20) Land and Land Rights | | | | | | 0 |
| 35.18 | (338.21) Structures and Improvements | | | | | | 0 |
| 35.20 | (338.23) Wind Turbines | | | | | | 0 |
| 35.21 | (338.24) Wind Towers and Fixtures | | | | | | 0 |
| 35.23 | (338.26) Collector System | | | | | | 0 |
| 35.24 | (338.27) Generator Step-up Transformers (GSU) | | | | | | 0 |
| 35.25 | (338.28) Inverters | | | | | | 0 |
| 35.26 | (338.29) Other Accessory Electrical Equipment | | | | | | 0 |
| 35.27 | (338.30) Computer Hardware | | | | | | 0 |
| 35.28 | (338.31) Computer Software | | | | | | 0 |
| 35.29 | (338.32) Communication Equipment | | | | | | 0 |
| 35.30 | (338.33) Miscellaneous Power Plant Equipment | | | | | | 0 |
| 35.31 | (338.34) Asset Retirement Costs for Wind Production | | | | | | 0 |
| 35.32 | TOTAL Wind Production Plant (Enter Total of lines 35.17 thru 35.31) | 0 | 0 | 0 | 0 | 0 | 0 |
| 35.33 | F. Other Renewable Production Plant | | | | | | |
| 35.34 | (339.1) Land and Land Rights | | | | | | 0 |
| 35.35 | (339.2) Structures and Improvements | | | | | | 0 |
| 35.36 | (339.3) Fuel Holders | | | | | | 0 |
| 35.37 | (339.4) Boilers | | | | | | 0 |
| 35.39 | (339.6) Generators | | | | | | 0 |
| 35.41 | (339.8) Other Accessory Electrical Equipment | | | | | | 0 |
| 35.42 | (339.9) Computer Hardware | | | | | | 0 |
| 35.43 | (339.10) Computer Software | | | | | | 0 |
| 35.44 | (339.11) Communication Equipment | | | | | | 0 |
| 35.45 | (339.12) Miscellaneous Power Plant Equipment | | | | | | 0 |
| 35.46 | (339.13) Asset Retirement Costs for Other Renewable Production | | | | | | 0 |
| 35.47 | TOTAL Other Renewable Production Plant (Enter Total of lines 35.34 thru 35.46) | 0 | 0 | 0 | 0 | 0 | 0 |
| 36 | G. Other Production Plant | | | | | | |
| 37 | (340) Land and Land Rights | 905,167 | | | | | 905,167 |
| 38 | (341) Structures and Improvements | 17,590,259 | 130,921 | 79,010 | | | 17,642,170 |
| 39 | (342) Fuel Holders, Products, and Accessories | 21,073,070 | 14,510 | | | | 21,087,580 |
| 40 | (343) Prime Movers | 21,395,145 | | 2,747 | | | 21,392,398 |
| 41 | (344) Generators | 239,892,608 | 1,882,222 | 497,776 | | | 241,277,054 |
| 42 | (345) Accessory Electric Equipment | 27,357,892 | 4,077,180 | 441,557 | | | 30,993,515 |
| 42.1 | (345.1) Computer Hardware | | | | | | 0 |
| 42.2 | (345.2) Computer Software | | 11,606 | 25,757 | | 175,423 | 161,272 |
| 42.3 | (345.3) Communication Equipment | | 364,959 | 132,663 | | 894,614 | 1,126,910 |
| 43 | (346) Misc. Power Plant Equipment | 1,625,617 | 7,255 | | | | 1,632,872 |
| 44 | (347) Asset Retirement Costs for Other Production | 351,683 | | | | | 351,683 |
| 45 | TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44) | 330,191,441 | 6,488,653 | 1,179,510 | 0 | 1,070,037 | 336,570,621 |
| 46 | TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, 35.15, 35.32, 35.47, and 45) | 1,639,674,225 | 69,828,383 | 14,884,057 | 0 | 5,431,312 | 1,700,049,863 |
| 47 | 3. Transmission Plant | | | | | | |
| 48 | (350) Land and Land Rights | 30,047,176 | 231,456 | | | 1,352,293 | 31,630,925 |
| 48.2 | (351.1) Computer Hardware | | 6,272 | 9,716 | | 272,865 | 269,421 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 48.3 | (351.2) Computer Software | | 1,496,960 | 258,841 | | 1,572,648 | 2,810,767 |
| 48.4 | (351.3) Communication Equipment | | 11,657 | 15,547 | | 3,570,567 | 3,566,677 |
| 49 | (352) Structures and Improvements | 39,761,979 | 302,195 | 19,512 | | | 40,044,662 |
| 50 | (353) Station Equipment | 407,981,747 | 10,446,359 | 553,697 | | | 417,874,409 |
| 51 | (354) Towers and Fixtures | 17,267,467 | 180,705 | | | | 17,448,172 |
| 52 | (355) Poles and Fixtures | 399,855,616 | 21,366,402 | 390,960 | | | 420,831,058 |
| 53 | (356) Overhead Conductors and Devices | 194,217,868 | 8,844,411 | 351,387 | | | 202,710,892 |
| 54 | (357) Underground Conduit | 3,727,360 | 438,770 | | | | 4,166,130 |
| 55 | (358) Underground Conductors and Devices | 7,204,897 | 438,770 | | | | 7,643,667 |
| 56 | (359) Roads and Trails | 2,633,174 | 37,701 | | | | 2,670,875 |
| 57 | (359.1) Asset Retirement Costs for Transmission Plant | | | | | | 0 |
| 58 | TOTAL Transmission Plant (Enter Total of lines 48 thru 57) | 1,102,697,284 | 43,801,658 | 1,599,660 | 0 | 6,768,373 | 1,151,667,655 |
| 59 | 4. Distribution Plant | | | | | | |
| 60 | (360) Land and Land Rights | 16,755,079 | 1,386,685 | | | 2,086,848 | 20,228,612 |
| 61 | (361) Structures and Improvements | 43,225,673 | 2,715,139 | 639,768 | | 32,824 | 45,333,868 |
| 62 | (362) Station Equipment | 186,418,766 | 16,187,163 | 1,311,945 | | (21,838) | 201,272,146 |
| 63.1 | (363.1) Computer Hardware | | 2,587,942 | | | 1,449,806 | 4,037,748 |
| 63.2 | (363.2) Computer Software | | 13,261,725 | 2,911,158 | | 12,846,339 | 23,196,906 |
| 63.3 | (363.3) Communication Equipment | | 6,681,787 | 42,016 | | 2,466,511 | 9,106,282 |
| 64 | (364) Poles, Towers, and Fixtures | 620,062,693 | 68,004,916 | 780,745 | | | 687,286,864 |
| 65 | (365) Overhead Conductors and Devices | 392,725,767 | 8,652,207 | 86,823 | | | 401,291,151 |
| 66 | (366) Underground Conduit | 187,276,617 | 11,980,894 | 524,408 | | | 198,733,103 |
| 67 | (367) Underground Conductors and Devices | 308,694,344 | 17,933,005 | 10,608,569 | | (1,756,116) | 314,262,664 |
| 68 | (368) Line Transformers | 390,417,533 | 41,422,470 | 40,321 | | | 431,799,682 |
| 69 | (369) Services | 236,568,104 | 2,285,680 | 40,949 | | | 238,812,835 |
| 70 | (370) Meters | 88,896,009 | 2,037,573 | 192,572 | | | 90,741,010 |
| 71 | (371) Installations on Customer Premises | 12,988,424 | 3,917,658 | 121,449 | | (1,850,897) | 14,933,736 |
| 72 | (372) Leased Property on Customer Premises | | | | | | 0 |
| 73 | (373) Street Lighting and Signal Systems | 88,958,828 | (1,079,215) | 108,374 | | | 87,771,239 |
| 74 | (374) Asset Retirement Costs for Distribution Plant | | | | | | 0 |
| 75 | TOTAL Distribution Plant (Enter Total of lines 60 thru 74) | 2,572,987,837 | 197,975,629 | 17,409,097 | 0 | 15,253,477 | 2,768,807,846 |
| 76 | 5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT | | | | | | |
| 77 | (380) Land and Land Rights | | | | | | 0 |
| 78 | (381) Structures and Improvements | | | | | | 0 |
| 79 | (382) Computer Hardware | | | | | | 0 |
| 80 | (383) Computer Software | | | | | | 0 |
| 81 | (384) Communication Equipment | | | | | | 0 |
| 82 | (385) Miscellaneous Regional Transmission and Market Operation Plant | | | | | | 0 |
| 83 | (386) Asset Retirement Costs for Regional Transmission and Market Oper | | | | | | 0 |
| 84 | TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83) | 0 | 0 | 0 | 0 | 0 | 0 |
| 84.1 | 6. ENERGY STORAGE PLANT | | | | | | |
| 84.2 | (387.1) Land and Land Rights | | | | | | 0 |
| 84.3 | (387.2) Structures and Improvements | | | | | | 0 |
| 84.4 | (387.3) Energy Storage Equipment | | | | | | 0 |
| 84.6 | (387.5) Collector System | | | | | | 0 |
| 84.7 | (387.6) Generator Step-up Transformers (GSU) | | | | | | 0 |
| 84.8 | (387.7) Inverters | | | | | | 0 |
| 84.9 | (387.8) Computer Hardware | | | | | | 0 |
| 84.10 | (387.9) Computer Software | | | | | | 0 |
| 84.11 | (387.10) Communication Equipment | | | | | | 0 |
| 84.12 | (387.11) Miscellaneous Energy Storage Equipment | | (1,756,116) | | | 3,607,013 | 1,850,897 |
| 84.13 | (387.12) Asset Retirement Costs for Energy Storage | | | | | | 0 |
| 84.14 | TOTAL Energy Storage Plant (Total lines 84.2 thru 84.13) | 0 | (1,756,116) | 0 | 0 | 3,607,013 | 1,850,897 |
| 85 | 7. General Plant | | | | | | |
| 86 | (389) Land and Land Rights | 1,083,006 | | | | | 1,083,006 |
| 87 | (390) Structures and Improvements | 21,571,656 | 195,985 | 24,692 | | | 21,742,949 |
| 88 | (391) Office Furniture and Equipment | 4,131,538 | 262,062 | | | (4,267,192) | 126,408 |
| 89 | (392) Transportation Equipment | 64,884,551 | 6,512,410 | 1,556,936 | | (110,118) | 69,729,907 |
| 90 | (393) Stores Equipment | 472,784 | | | | | 472,784 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 91 | (394) Tools, Shop and Garage Equipment | 10,611,151 | 1,144,510 | 176,701 | | | 11,578,960 |
| 92 | (395) Laboratory Equipment | 3,394,638 | 1,166,521 | 284,391 | | | 4,276,768 |
| 93 | (396) Power Operated Equipment | 23,102,388 | 1,367,504 | 849,545 | | | 23,620,347 |
| 94 | (397.1) Computer Hardware | | (56,067) | 855,154 | | 2,532,908 | 1,621,687 |
| 94.1 | (397.2) Computer Software | | 2,872,394 | 4,149,235 | | 34,175,772 | 32,898,931 |
| 94.2 | (397.3) Communication Equipment | 41,203,403 | (836,680) | 2,187,318 | | (11,403,784) | 26,775,621 |
| 95 | (398) Miscellaneous Equipment | 238,998 | 3,022 | | | | 242,020 |
| 96 | SUBTOTAL (Enter Total of lines 86 thru 95) | 170,694,113 | 12,631,661 | 10,083,972 | 0 | 20,927,586 | 194,169,388 |
| 97 | (399) Other Tangible Property | | | | | | 0 |
| 98 | (399.1) Asset Retirement Costs for General Plant | | | | | | 0 |
| 99 | TOTAL General Plant (Enter Total of lines 96, 97, and 98) | 170,694,113 | 12,631,661 | 10,083,972 | 0 | 20,927,586 | 194,169,388 |
| 100 | TOTAL (Accounts 101 and 106) | 5,594,245,021 | 322,578,046 | 43,976,786 | 0 | 2,909,809 | 5,875,756,090 |
| 101 | (102) Electric Plant Purchased (See Instr. 8) | | | | | | 0 |
| 102 | (Less) (102) Electric Plant Sold (See Instr. 8) | | | | | | 0 |
| 103 | (103) Experimental Plant Unclassified | | | | | | 0 |
| 104 | TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103) | 5,594,245,021 | 322,578,046 | 43,976,786 | 0 | 2,909,809 | 5,875,756,090 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

| Line No. | Description and Location of Property (a) | Date Originally Included in This Account (b) | Date Expected to be used in Utility Service (c) | Balance at End of Year (d) |
|---|---|---|---|---|
| 1 | Land and Rights: | | | |
| 2 | Other Property: | | | |
| 3 | Distribution Plant Land, Spokane Washington | 03/01/2020 | 12/31/2026 | 540,307 |
| 4 | Distribution Plant Land, Melville, Washington | 01/01/2020 | 12/31/2030 | 5,072,099 |
| 5 | Distribution Plant Land, Spokane, Washington | 01/01/2020 | 12/31/2040 | 441,158 |
| 6 | Distribution Plant Land, Pullman, Washington | 02/01/2022 | 12/31/2040 | 533,394 |
| 7 | Distribution Plant Land, Othello, Washington | 04/01/2022 | 12/31/2040 | 229,261 |
| 8 | Distribution Plant Land, Spokane, Washington | 11/01/2023 | 12/31/2040 | 2,104,129 |
| 9 | Distribution Plant Land, Spokane, Washington | 06/01/2024 | 12/31/2029 | 1,571,448 |
| 10 | Transmission Plant Land, Spokane, Washington | 06/01/2018 | 01/01/2026 | 1,290,393 |
| 11 | Transmission Plant Land, Nine Mile Falls, Washington | 03/01/2022 | 12/31/2027 | 546,503 |
| 12 | Transmission Plant Land, Noxon, MT | 10/01/2016 | 01/01/2026 | 3,233,061 |
| 13 | Distribution Plant Land, Carlin Bay, Idaho | 12/01/2010 | 12/31/2029 | 162,352 |
| 14 | Distribution Plant Land, Coeur d'Alene, Idaho | 12/01/2021 | 12/31/2040 | 249,852 |
| 15 | Distribution Plant Land, Lewiston, Idaho | 06/01/2023 | 12/31/2030 | 1,430,930 |
| 16 | Distribution Plant Land, Post Falls, Idaho | 08/01/2024 | 12/31/2029 | 2,639,261 |
| 17 | Distribution Plant Land, Moscow, Idaho | 09/01/2024 | 12/31/2030 | 1,634,708 |
| 18 | Other Production Land, Rathdrum, Idaho | 12/01/2015 | 12/31/2034 | 3,490,607 |
| 19 | Transmission Plant Land, Sandpoint, Idaho | 05/01/2019 | 12/31/2028 | 486,299 |
| 20 | Transmission Plant Land, Harrison, Idaho | 12/01/2023 | 12/31/2030 | 340,836 |
| 21 | Other Property: | | | |
| 22 | | | | |
| 23 | | | | |
| 24 | | | | |
| 25 | | | | |
| 26 | | | | |
| 27 | | | | |
| 28 | | | | |
| 29 | | | | |
| 30 | | | | |
| 31 | | | | |
| 32 | | | | |
| 33 | | | | |
| 34 | | | | |
| 35 | | | | |
| 36 | | | | |
| 37 | | | | |
| 38 | | | | |
| 39 | | | | |
| 40 | | | | |
| 41 | | | | |
| 42 | | | | |
| 43 | | | | |
| 44 | | | | |
| 45 | | | | |
| 46 | | | | |
| 47 | TOTAL | | | 25,996,598 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
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## CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

| Line No. | Description of Project (a) | Construction work in progress - Electric (Account 107) (b) |
|---|---|---|
| 1 | Metro 115kV Substation | 35,797,788 |
| 2 | Garden Springs 230-115 kV Substation | 34,243,428 |
| 3 | Long Lake Plant Upgrades | 32,122,840 |
| 4 | PF North Channel Spillway Repl | 30,871,115 |
| 5 | LL HED Stability Enhancement | 11,850,021 |
| 6 | Substation - Capital Spares | 11,627,784 |
| 7 | Substation Rebuilds | 9,328,112 |
| 8 | Coyote Springs 2 CT Rotor Replacement | 8,808,016 |
| 9 | Noxon Rapids Gantry Crane Modernization | 8,486,853 |
| 10 | New Substations | 7,111,227 |
| 11 | Strategic Initiatives | 6,358,515 |
| 12 | East CDA Lake Reinforcement Program | 5,092,669 |
| 13 | Generation Interconnection | 4,231,377 |
| 14 | Operational Sustainment | 3,947,374 |
| 15 | Nine Mile Units 3 & 4 Control Upgrade | 3,099,304 |
| 16 | Wildfire Resiliency | 3,048,523 |
| 17 | HMI Control Software | 2,986,796 |
| 18 | Substation Asset Mgmt Capital Maintenance | 2,686,481 |
| 19 | Distribution - Spokane North & West | 2,386,572 |
| 20 | Boulder Park Engine Controls Upgrade | 2,211,520 |
| 21 | Transmission Minor Rebuild | 2,090,141 |
| 22 | Transportation Equip | 1,676,982 |
| 23 | Distribution - CdA East & North | 1,614,149 |
| 24 | Tribal Permits and Settlements | 1,479,927 |
| 25 | Idaho AMI | 1,337,971 |
| 26 | Noxon Rapids Unit Upgrades | 1,309,718 |
| 27 | MLK Solar Plus Storage Microgrid | 1,304,355 |
| 28 | Operational Safety and Compliance | 1,269,673 |
| 29 | Coyote Springs 2 Replace Cooling Tower | 1,188,233 |
| 30 | Generation, Substation & Gas Location Security | 1,103,419 |
| 31 | Post Falls Redevelopment | 1,034,406 |
| 32 | Minor Projects < $1M | 10,555,912 |
| 43 | Total | 252,261,201 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

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

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 12, column (c), and that reported for electric plant in service, page 204, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

| Line No. | Item (a) | Total (c + d + e) (b) | Electric Plant in Service (c) | Electric Plant Held for Future Use (d) | Electric Plant Leased To Others (e) |
|---|---|---|---|---|---|
| | **Section A. Balances and Changes During Year** | | | | |
| 1 | Balance Beginning of Year | 2,038,316,809 | 2,038,316,809 | 0 | 0 |
| 2 | Depreciation Provisions for Year, Charged to | | | | |
| 3 | (403) Depreciation Expense | 180,385,878 | 180,385,878 | | |
| 4 | (403.1) Depreciation Expense for Asset Retirement Costs | 0 | | | |
| 5 | (413) Exp. of Elec. Plt. Leas. to Others | 0 | | | |
| 6 | Transportation Expenses-Clearing | 3,364,789 | 3,364,789 | | |
| 7 | Other Clearing Accounts | 0 | | | |
| 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) | 183,750,667 | 183,750,667 | 0 | 0 |
| 11 | Net Charges for Plant Retired: | | | | |
| 12 | Book Cost of Plant Retired | (40,190,431) | (40,190,431) | | |
| 13 | Cost of Removal | (7,380,371) | (7,380,371) | | |
| 14 | Salvage (Credit) | 598,406 | 598,406 | | |
| 15 | TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14) | (46,972,396) | (46,972,396) | 0 | 0 |
| 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 | Difference of DJ105 Accrual from 2024 to 2025 | (7,092) | (7,092) | | |
| 17.3 | ARO Depreciation | 2,842,063 | 2,842,063 | | |
| 17.4 | Transfers | 24,852,565 | 24,852,565 | | |
| 17.5 | Change in Removal Work in Progress | 1,692,248 | 1,692,248 | | |
| 17.6 | Common General Plant Allocated | (19,699,928) | (19,699,928) | | |
| 17.7 | Immaterial COR Costs | 5,468 | 5,468 | | |
| 18 | Book Cost or Asset Retirement Costs Retired | 0 | | | |
| 19 | Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18) | 2,184,668,124 | 2,184,668,124 | 0 | 0 |
| | **Section B. Balances at End of Year According to Functional Classification** | | | | |
| 20 | Steam Production | 432,784,176 | 432,784,176 | | |
| 21 | Nuclear Production | 0 | | | |
| 22 | Hydraulic Production-Conventional | 234,331,233 | 234,331,233 | | |
| 23 | Hydraulic Production-Pumped Storage | 0 | | | |
| 23.1 | Solar Production | 0 | | | |
| 23.2 | Wind Production | 0 | | | |
| 23.3 | Other Renewable Production | 0 | | | |
| 24 | Other Production | 197,391,839 | 197,391,839 | | |
| 25 | Transmission | 332,062,428 | 332,062,428 | | |
| 26 | Distribution | 891,814,519 | 891,814,519 | | |
| 27 | Regional Transmission and Market Operation | 0 | | | |
| 27.1 | Energy Storage | 495,447 | 495,447 | | |
| 28 | General | 95,788,482 | 95,788,482 | | |
| 29 | TOTAL (Enter Total of lines 20 thru 28) | 2,184,668,124 | 2,184,668,124 | 0 | 0 |

## INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder the information called for below. Sub-TOTAL by company and give a TOTAL in columns (e), (f), (g) and (h). (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate. (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1.

| Line No. | Description of Investment (a) | Date Acquired (b) | Date of Maturity (c) | Amount of Investment at Beginning of Year (d) | Equity in Subsidiary Earnings of Year (e) | Revenues for Year (f) | Amount of Investment at End of Year (g) | Gain or Loss from Investment Disposed of (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | Investment in Avista Capital | 01/01/1997 | | 256,138,971 | | | 256,138,971 | |
| 2 | Avista Capital - Equity in Earnings | | | (117,276,420) | (12,899,515) | | (130,175,935) | |
| 3 | Investment in AERC | 07/01/2014 | | 89,816,380 | | | 89,816,380 | |
| 4 | AERC - Equity in Earnings | | | 33,063,281 | 5,758,509 | | 38,821,790 | |
| 42 | Total Cost of Account 123.1 $ | | Total | 261,742,212 | (7,141,006) | | 254,601,206 | |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## MATERIALS AND SUPPLIES

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

| Line No. | Account (a) | Balance Beginning of Year (b) | Balance End of Year (c) | Department or Departments which Use Material (d) |
|---|---|---|---|---|
| 1 | Fuel Stock (Account 151) | 6,331,080 | 3,558,417 | |
| 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) | 81,166,828 | 65,546,319 | |
| 6 | Assigned to - Operations and Maintenance | | | |
| 7 | Production Plant (Estimated) | 6,695,684 | 990,077 | |
| 8 | Transmission Plant (Estimated) | 136,004 | 255,143 | |
| 9 | Distribution Plant (Estimated) | 938,011 | 54,350 | |
| 10 | Regional Transmission and Market Operation Plant (Estimated) | | | |
| 10.1 | Energy Storage Plant (Estimated) | | | |
| 11 | Assigned to - Other (provide details in footnote) | 12,640,173 | [(a)]17,642,178 | |
| 12 | TOTAL Account 154 (Enter Total of lines 5 thru 11) | 101,576,700 | 84,488,067 | |
| 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 | 107,907,780 | 88,046,484 | |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

FOOTNOTE DATA

| (a) Concept: PlantMaterialsAndOperatingSuppliesOther |
|---|
| Various other non electric construction costs, O&M, A&G and various other expenses |

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|---|---|---|---|

## Allowances and Environmental Credits (Accounts 158.1, 158.2, 158.3, and 158.4)

1. Report below the details related to allowances and environmental credits. Additional information about the type of allowances/environmental credits required by other regulatory bodies can be disclosed within the footnote data.
2. Report all acquisitions of allowances and environmental credits at cost.
3. Report allowances and environmental credits in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances and environmental credits transactions by the period they are first eligible for use: the current year's allowances and environmental credits in columns (b)-(c), allowances and environmental credits for the three succeeding years in columns (d)-(i), starting with the following year, and allowances and environmental credits for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 authoritative agency issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by an authoritative agency. Report on Line 39 the authoritative agency's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the authoritative agency's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances and environmental credits acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances and environmental credits disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance and environmental credits sales.

| Line No. | Allowances and Environmental Credits Inventory (Accounts 158.1, 158.3, and 158.4) (a) | Current Year No. (b) | Current Year Amt. (c) | Year One No. (d) | Year One Amt. (e) | Year Two No. (f) | Year Two Amt. (g) | Year Three No. (h) | Year Three Amt. (i) | Future Years No. (j) | Future Years Amt. (k) | Totals No. (l) | Totals Amt. (m) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Balance-Beginning of Year | 1,711,000 | 1,175,388 | | | | | | | | | 1,711,000 | 1,175,388 |
| 2 | | | | | | | | | | | | | |
| 3 | Acquired During Year: | | | | | | | | | | | | |
| 4 | Issued (Less Withheld Allow) | | | | | | | | | | | 0 | 0 |
| 5 | Returned by authoritative agency | | | | | | | | | | | 0 | 0 |
| 6 | | | | | | | | | | | | | |
| 7 | | | | | | | | | | | | | |
| 8 | Purchases/Transfers: | | | | | | | | | | | 0 | 0 |
| 9 | Purchased: WA Carbon Allowances - Elec | (922) | 275,382 | | | | | | | | | (922) | 275,382 |
| 10 | Purchased: WA Carbon Allowances - Gas | 936,058 | 57,090,986 | | | | | | | | | 936,058 | 57,090,986 |
| 11 | | | | | | | | | | | | | |
| 12 | | | | | | | | | | | | | |
| 13 | | | | | | | | | | | | | |
| 14 | | | | | | | | | | | | | |
| 15 | Total | 935,136 | 57,366,368 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 935,136 | 57,366,368 |
| 16 | | | | | | | | | | | | | |
| 17 | Relinquished During Year: | | | | | | | | | | | | |
| 18 | Charges to Account 509, 555.2, and 555.3 | | 209,300 | | | | | | | | | 0 | 209,300 |
| 19 | Other: | | | | | | | | | | | | |
| 20 | Allowances Used | | | | | | | | | | | | |
| 21 | Cost of Sales/Transfers: | | | | | | | | | | | | |
| 22 | [(a)] WA Compliance Liability - Elec | | (205,975) | | | | | | | | | 0 | (205,975) |
| 23 | [(b)] WA Compliance Liability - Gas | | (53,354,549) | | | | | | | | | 0 | (53,354,549) |
| 24 | | | | | | | | | | | | | |
| 25 | | | | | | | | | | | | | |
| 26 | | | | | | | | | | | | | |
| 27 | | | | | | | | | | | | | |
| 28 | Total | 0 | (53,560,524) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (53,560,524) |
| 29 | Balance-End of Year | 2,646,136 | 4,981,232 | | | | | | | | | 2,646,136 | 4,981,232 |
| 30 | | | | | | | | | | | | | |
| 31 | Sales: | | | | | | | | | | | | |
| 32 | Net Sales Proceeds(Assoc. Co.) | | | | | | | | | | | 0 | 0 |
| 33 | Net Sales Proceeds (Other) | | | | | | | | | | | 0 | 0 |
| 34 | Gains | | | | | | | | | | | 0 | 0 |
| 35 | Losses | | | | | | | | | | | 0 | 0 |
| | Allowances Withheld (Acct 158.2) | | | | | | | | | | | | |
| 36 | Balance-Beginning of Year | | | | | | | | | | | 0 | 0 |
| 37 | Add: Withheld by authoritative agency | | | | | | | | | | | 0 | 0 |
| 38 | Deduct: Returned by authoritative agency | | | | | | | | | | | 0 | 0 |
| 39 | Cost of Sales | | | | | | | | | | | 0 | 0 |
| 40 | Balance-End of Year | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 41 | | | | | | | | | | | | | |
| 42 | Sales | | | | | | | | | | | | |
| 43 | Net Sales Proceeds (Assoc. Co.) | | | | | | | | | | | 0 | 0 |
| 44 | Net Sales Proceeds (Other) | | | | | | | | | | | 0 | 0 |
| 45 | Gains | | | | | | | | | | | 0 | 0 |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 46 | Losses | | | | | | | | | | | 0 | 0 |

FOOTNOTE DATA

| |
|---|
| (a) Concept: AllowancesInventoryCostOfSalesTransfersDescription |
| The provisions for Washington's Climate Commitment Act became applicable effective January 1, 2023. This line represents the estimated carbon liability for Avista's electric business as of December 31, 2025. |
| (b) Concept: AllowancesInventoryCostOfSalesTransfersDescription |
| The provisions for Washington's Climate Commitment Act became applicable effective January 1, 2023. This line represents the estimated carbon liability for Avista's natural gas business as of December 31, 2025. |

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**Transmission Service and Generation Interconnection Study Costs**

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

| Line No. | Description (a) | Costs Incurred During Period (b) | Account Charged (c) | Reimbursements Received During the Period (d) | Account Credited With Reimbursement (e) |
|---|---|---|---|---|---|
| 1 | **Transmission Studies** | | | | |
| 2 | NextEra Studies for TSRs | 57,946 | 186200 | | |
| 3 | #49 Rattlesnake SIS SIS | 1,111 | 186200 | | |
| 4 | Inland Power Snowdon Sub SIS | 1,088 | 186200 | | |
| 20 | Total | 60,145 | | 0 | |
| 21 | **Generation Studies** | | | | |
| 22 | Martinsdale Wind Proj #83 | 4,435 | 186200 | 0 | |
| 23 | Jane Wind 2 Proj #96 | 2,013 | 186200 | 0 | |
| 24 | Jane Wind Proj #95 | 2,445 | 186200 | 0 | |
| 25 | Broadview IV Project #107 | 2,949 | 186200 | 0 | |
| 26 | Ursus Wind Project #108 | 3,807 | 186200 | 0 | |
| 27 | Gordon Butte South Wind Q116 | 3,227 | 186200 | 0 | |
| 28 | Ursiane Wind #118 | 2,281 | 186200 | 0 | |
| 29 | Royal Slope - Juwi - ESA | 13,858 | 186200 | 0 | |
| 30 | Colstrip Solar Q121 | 2,535 | 186200 | 0 | |
| 31 | CA8C Othello 2024 Phase 1 | 8,573 | 186200 | 0 | |
| 32 | CA8C Othello 2024 Fclty Stdy | 29,556 | 186200 | 0 | |
| 33 | 2025 Cluster Study Open Window | 68,867 | 186200 | 25,005 | 186210 |
| 34 | 2025 CS CA3 CDA P1 | 7,220 | 186200 | 0 | |
| 35 | 2025 CS CA3 CDA P1 Restudy | 1,885 | 186200 | 0 | |
| 36 | 2025 CS CA3 CDA P2 | 4,884 | 186200 | 0 | |
| 37 | 2025 CS CA1 Spokane P1 | 13,823 | 186200 | 3,083 | 186210 |
| 38 | 2025 CS CA1 Spokane P1 Restudy | 16,596 | 186200 | 0 | |
| 39 | 2025 CS CA1 Spokane P2 | 1,028 | 186200 | 0 | |
| 40 | 2025 CS CA5 Palouse P1 | 11,155 | 186200 | 2,890 | 186210 |
| 41 | 2025 CS CA5 Palouse P1 Restudy | 12,669 | 186200 | 0 | |
| 42 | 2025 CS CA6 Lewis Clark P1 | 8,690 | 186200 | 3,684 | 186210 |
| 43 | 2025 CS CA6 Lewis Clark P2 | 1,882 | 186200 | 489 | 186210 |
| 44 | 2025 CS CA6 LC P2 Restudy | 2,077 | 186200 | 0 | |
| 45 | 2025 CS CA7 Big Bend P1 | 19,139 | 186200 | 10,193 | 186210 |
| 46 | 2025 CS CA7 Big Bend P1 Restudy | 15,755 | 186200 | 0 | |
| 47 | 2025 CS CA8 Melville P1 | 5,967 | 186200 | 0 | |
| 48 | Facilities Study CS25-18 | 9,234 | 186200 | 0 | |
| 49 | Q97 Lolo Unsuspension Study | 2,589 | 186200 | 0 | |
| 50 | 2025 CS CA7 Big Bend P1 Restudy #2 | 980 | 186200 | 0 | |
| 51 | 2025 CS CA5 Palouse P2 | 562 | 186200 | 0 | |
| 52 | ENEL Studies for TSR | 112,967 | 186200 | 112,967 | 186210 |
| 53 | CA1 West Plains 2024 Phase 1 | 71,382 | 186200 | 71,382 | 186210 |
| 54 | CA1 West Plains 2024 Phase 2 | 22,630 | 186200 | 22,630 | 186210 |
| 55 | CA1 West Plains 2024 Phase 2 Restudy | 11,774 | 186200 | 11,774 | 186210 |
| 56 | CA1 Facilities Study CS24-15 | 38,895 | 186200 | 38,895 | 186210 |
| 57 | CA1 Facilities Study CS24-14 | 23,319 | 186200 | 23,319 | 186210 |
| 58 | CA8B Othello 2024 Phase 1 | 8,371 | 186200 | 8,371 | 186210 |
| 59 | CA8B Othello 2024 Fclty Study | 27,534 | 186200 | 27,534 | 186210 |
| 60 | 2025 CS CA2 Stratford P1 | 7,560 | 186200 | 7,560 | 186210 |
| 61 | CS PV Q113 | 1,955 | 186200 | 1,955 | 186210 |
| 62 | CS Wind 2 Q115 | 1,618 | 186200 | 1,618 | 186210 |
| 63 | CS Wind 1 Q114 | 1,817 | 186200 | 1,817 | 186210 |
| 39 | Total | 610,503 | | 375,166 | |
| 40 | Grand Total | [a]670,648 | | [b]375,166 | |

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: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## OTHER REGULATORY ASSETS (Account 182.3)

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

| Line No. | Description and Purpose of Other Regulatory Assets (a) | Balance at Beginning of Current Quarter/Year (b) | Debits (c) | CREDITS Written off During Quarter/Year Account Charged (d) | CREDITS Written off During the Period Amount (e) | Balance at end of Current Quarter/Year (f) |
|---|---|---|---|---|---|---|
| 1 | [a] WA Excess Nat Gas Line Extension Allowance | 1,032,853 | 0 | 407 | 387,598 | 645,255 |
| 2 | [b] Reg Asset Post Ret Liabilility | 102,085,201 | 841,954 | 228 | 32,295,059 | 70,632,096 |
| 3 | [c] Regulatory Asset FAS 109 Utility Plant | 11,518,508 | 0 | 283 | 942,240 | 10,576,268 |
| 4 | [d] Regulatory Asset FAS 109 DSIT Non Plant | 64,368,795 | 1,842,350 | 283 | 6,250,199 | 59,960,946 |
| 5 | [e] Regulatory Asset Lake CDA Settlement-Varies | 35,575,547 | 0 | 407 | 1,116,805 | 34,458,742 |
| 6 | [f] Reg Asset Decoupling Surcharges | 6,671,140 | 47,660,149 | 456, 495 | 37,710,197 | 16,621,092 |
| 7 | [g] Reg Asset Colstrip ARO | 25,305,626 | 9,298,793 | 407 | 2,410,429 | 32,193,990 |
| 8 | [h] Regulatory Asset FAS 143 ARO | 2,438,351 | 146,519 | | 0 | 2,584,870 |
| 9 | [i] Regulatory Asset Workers Comp | 1,905,271 | 262,487 | 242 | 294,574 | 1,873,184 |
| 10 | [j] Interest Rate Swap Asset | 172,332,927 | 0 | 242 | 6,973,314 | 165,359,613 |
| 11 | [k] DSM Asset | 41,875,254 | 23,316,125 | 908 | 3,163,288 | 62,028,091 |
| 12 | [l] Deferred ITC | 3,588,268 | 0 | 283, 410 | 104,989 | 3,483,279 |
| 13 | [m] Regulatory Asset MDM System | 26,309,453 | 0 | 407 | 3,035,706 | 23,273,747 |
| 14 | [n] Regulatory Asset BPA Residential Exchange | 412,228 | 656,113 | 407 | 1,068,341 | 0 |
| 15 | [o] Regulatory Asset AFUDC (PIS,WIP) & Equity DFIT | 49,019,728 | 52,289,208 | Various | 50,316,073 | 50,992,863 |
| 16 | [p] Existing Meters/ERTS Retirement Def | 15,810,842 | 0 | 407 | 1,824,328 | 13,986,514 |
| 17 | [q] Regulatory Asset COVID-19 | 263,116 | 148,024 | 407 | 411,140 | 0 |
| 18 | [r] Regulatory Asset Energy Imbalance Market | 233,040 | 0 | 407 | 233,040 | 0 |
| 19 | [s] Regulatory Asset Wildfire Resiliency & Balancing | 22,475,687 | 11,092,107 | 407 | 7,754,816 | 25,812,978 |
| 20 | [t] Deferral for CS2 & Colstrip O&M | 3,843,312 | 5,295,766 | 407 | 3,045,075 | 6,094,003 |
| 21 | [u] Regulatory Asset Tax Basis Flow Through | 149,647,793 | 4,414,199 | 282, 283 | 1,173,287 | 152,888,705 |
| 22 | [v] Regulatory Asset Commodity MTM ST & LT | 40,564,079 | 0 | 175, 244 | 10,843,962 | 29,720,117 |
| 23 | [w] Reg Asset Insurance Balancing Acct | 11,068,621 | 9,753,004 | 407 | 5,352,664 | 15,468,961 |
| 24 | [x] Reg Asset Energy Efficiency | 425,951 | 65,797 | 242 | 325,134 | 166,614 |
| 25 | [y] Deferred Regulatory Fees | 4,041,770 | 184,590 | 407 | 2,189,926 | 2,036,434 |
| 26 | [z] Regulatory Asset Pension Settlement Deferral | 9,856,324 | 0 | 407 | 985,632 | 8,870,692 |
| 27 | [aa] Reg Asset CCA | 49,647,770 | 54,356,139 | 407 | 79,611,414 | 24,392,495 |
| 28 | [ab] WA ERM Deferral | 25,375,193 | 16,207,072 | 557 | 17,117,959 | 24,464,306 |
| 29 | [ac] Reg Asset MT Riverbed Escrow Int | 1,665,036 | 0 | 407 | 628,412 | 1,036,624 |
| 30 | [ad] Reg Asset PPA Interest Deferral | 383,630 | 9,752 | 407 | 383,630 | 9,752 |
| 31 | [ae] Reg Liab Tax Customer Credit | 2,926,457 | 364,956 | | 0 | 3,291,413 |
| 32 | [af] Misc Reg Asset | 136,546 | 278,375 | 407 | 98,060 | 316,861 |
| 33 | [ag] Regulatory Asset Turner Battery Storage | 0 | 3,422,093 | 407 | 1,711,047 | 1,711,046 |
| 34 | [ah] Reg Asset CPP | 0 | 646,198 | 407 | 89,921 | 556,277 |
| 35 | [ai] Regulatory Asset AFUDC Equity DFIT | 10,607,262 | 3,499,189 | 282, 283 | 1,231,368 | 12,875,083 |
| 36 | [aj] Reg Asset ERP Deferral | 0 | 1,757,172 | | 0 | 1,757,172 |
| 44 | TOTAL | 893,411,579 | 247,808,131 | | 281,079,627 | 860,140,083 |

| Name of Respondent:<br>Avista Corporation | This report is:<br>(1) ☑ An Original<br>(2) ☐ A Resubmission | Date of Report:<br>04/17/2026 | Year/Period of Report<br>End of: 2025/ 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

State deferred tax flow through balance.

(e) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

WA Docket No UE-080416; ID order AVU-E-08-01. Amortize through 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, amortization period is 33.75 years as per Order 09, dockets UE-190334, UG-190335, UE-190222 (Consolidated). For ID, amortization is 34.75 years as per Order 34276, AVU-E-18-03. Amortization 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

Amortization period varies depending on timing of transactions.

(l) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Deferred federal investment tax credits. Amortization occurs over remaining book life of respective utility plant assets.

(m) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Deferral of depreciation related to new WA AMI meters and the MDM system between the time of in-service and when they were included in rate base per WA Docket Nos. UE-170327 and UG-170328. Amortization is over remaining useful life, which is through 2033.

(n) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Refers to Rider 59-Residential and Farm Energy Rate adjustment resulting from an agreement between Avista and Bonneville Power Administration covering Residential Exchange Program benefits.

(o) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Deferring the difference between FERC formula and State approved AFUDC rates from 2010 to present.

(p) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Deferral of the NBV of meters that were replaced as part of the WA AMI implementation per UE-170327 and UG-170328. Amortization is over remaining useful life, which is through 2033.

(q) 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.

(r) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

ID PUC Order No 34606. Deferral of costs related to Avista's entry in the Energy Imbalance Market in March 2022.

(s) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Deferral of O&M wildfire expenses as per ID PUC Order 34883 and WA Dockets UE-200900, UG-200901, and UE-200894.

(t) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Deferral of CS2 and Colstrip O&M costs above set base per ID Order 32371; amortization period varies.

(u) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Deferred tax flow through balance on the mixed service costs and meter tax basis adjustments in accordance with 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.

(v) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Energy commodity derivative liability offset per WA Docket No UE-002066 and ID Order No 28648.

(w) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

To defer insurance costs above or below the baseline in accordance with WA Order 08 Docket Nos. UE-240006, UG-240007, and ID Order 35909 Docket Nos. AVU-E-23-01, AVU-G-23-01.

(x) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

To defer costs of compliance for CPP (OR - UM 2254) and CCA (WA - Doc. UG-220803) in relation to energy efficiency programs to reduce GHG for natural gas customers.

(y) 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.

(z) 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.

(aa) 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; amortization period varies.

(ab) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Washington Energy Recovery Mechanism; amortization period varies.

(ac) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

| |
|---|
| Per AVU-E-23-6 and UE-230548, deferral for the Montana Riverbed land lease agreement escrow release provisions following Avista and State of Montana Agreement on an updated balance owed. |
| (ad) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets |
| Accrued interest on power purchase agreements in connection with the clean energy action plan per RCW 80.28.410; balance amortized over one year. |
| (ae) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets |
| Deferral and amortization resulting from the approval of flow through tax treatment for IDD#5 and meters basis adjustments. |
| (af) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets |
| Grouped minor items. |
| (ag) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets |
| Turner battery storage deferral; amortization of balance in 2025 and 2026. |
| (ah) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets |
| Deferral of costs of compliance with CPP (OR UM2361). |
| (ai) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets |
| Deferred tax flow through balance on the AFUDC Equity tax basis adjustment. |
| (aj) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets |
| Deferral of O&M costs associated with ERP per WA Dockets UE-250576 & UG-250577, ID Case Nos. AVU-E-25-06 & AVU-G-25-04, and OR Docket No. 2396. |

| Name of Respondent:<br>Avista Corporation | This report is:<br>(1) ☑ An Original<br>(2) ☐ A Resubmission | Date of Report:<br>04/17/2026 | Year/Period of Report<br>End of: 2025/ Q4 |
|---|---|---|---|

## MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

| Line No. | Description of Miscellaneous Deferred Debits (a) | Balance at Beginning of Year (b) | Debits (c) | CREDITS | | Balance at End of Year (f) |
|---|---|---|---|---|---|---|
| | | | | Credits Account Charged (d) | Credits Amount (e) | |
| 1 | Reg Asset - Battery Storage | 3,422,093 | 0 | 407 | 3,422,093 | 0 |
| 2 | Plant Alloc of Clearing Journal | 11,246,603 | 1,952,853 | | 0 | 13,199,456 |
| 3 | Reg Asset - ERM | 10,505,945 | 49,938,749 | | 0 | 60,444,694 |
| 4 | WA REC Deferral | 0 | 1,894,604 | | 0 | 1,894,604 |
| 5 | Reg Asset - Decoupling Deferred | 19,100,281 | 14,107,415 | | 0 | 33,207,696 |
| 6 | Reg Asset - COVID 19 Deferral | 11,484,555 | 0 | VAR | 4,782,460 | 6,702,095 |
| 7 | Reg Asset - CEIP | 2,845,098 | 0 | 407 | 48,943 | 2,796,155 |
| 8 | Reg Asset - Williams Outage | 9,651,547 | 0 | 407 | 39,881 | 9,611,666 |
| 9 | Misc Deferred Debits- Pension | 35,399,068 | 25,631,416 | | 0 | 61,030,484 |
| 10 | Nez Perce Settlement | 98,373 | 0 | 557 | 5,188 | 93,185 |
| 11 | Misc Deferred Debit CSS Unpostable Cash Suspense | 0 | 9,594 | | 0 | 9,594 |
| 12 | Credit Union Labor Expenses | 0 | 100,168 | | 0 | 100,168 |
| 13 | CGDF - Siphon System Upgrade | 0 | 135,450 | | 0 | 135,450 |
| 14 | DCL Inter Study 3 DsnConst | 372,096 | 0 | VAR | 372,096 | 0 |
| 15 | ENEL Studies for TSR | 100,421 | 0 | VAR | 100,421 | 0 |
| 16 | Network Future State | 254,378 | 0 | VAR | 254,378 | 0 |
| 17 | Misc. Deferred Debits <$100,000 | (408,135) | 164,324 | | 0 | (243,811) |
| 47 | Miscellaneous Work in Progress | | | | | |
| 48 | Deferred Regulatory Comm. Expenses (See pages 350 - 351) | | | | | |
| 49 | TOTAL | 104,072,323 | | | | 188,981,436 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

| Line No. | Description and Location (a) | Balance at Beginning of Year (b) | Balance at End of Year (c) |
|---|---|---|---|
| 1 | Electric | | |
| 2 | Electric | 58,173,189 | 52,246,710 |
| 7 | Other | | |
| 8 | TOTAL Electric (Enter Total of lines 2 thru 7) | 58,173,189 | 52,246,710 |
| 9 | Gas | | |
| 10 | Gas | 22,258,935 | 49,618,121 |
| 15 | Other | | |
| 16 | TOTAL Gas (Enter Total of lines 10 thru 15) | 22,258,935 | 49,618,121 |
| 17.1 | [(a)] Other | 73,690,794 | 65,139,594 |
| 17 | Other (Specify) | | |
| 18 | TOTAL (Acct 190) (Total of lines 8, 16 and 17) | 154,122,918 | 167,004,425 |

**Notes**

(a) Concept: DescriptionOfAccumulatedDeferredIncomeTax

| | Beg. Balance | End. Balance |
|---|---|---|
| Pension, Medical, and SERP | 31,876,832 | 25,088,485 |
| Federal Income Tax Carryforwards | 1,202,010 | 84,000 |
| State Income Tax Carryforwards | 21,234,188 | 20,323,822 |
| Derivative Instruments | 10,631,115 | 7,937,555 |
| Compensation and Payroll | 7,010,014 | 7,269,073 |
| Plant Excess Deferred Gross Up | 3,340,097 | 2,728,481 |
| Other Common Deferred Tax Assets | (1,603,462) | 1,708,178 |
| Total | 73,690,794 | 65,139,594 |

| | | | |
|---|---|---|---|
| Name of Respondent:<br>Avista Corporation | This report is:<br>(1) ☑ An Original<br>(2) ☐ A Resubmission | Date of Report:<br>04/17/2026 | Year/Period of Report<br>End of: 2025/ Q4 |

**CAPITAL STOCKS (Account 201 and 204)**

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

| Line No. | Class and Series of Stock and Name of Stock Series (a) | Number of Shares Authorized by Charter (b) | Par or Stated Value per Share (c) | Call Price at End of Year (d) | Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e) | Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f) | Held by Respondent As Reacquired Stock (Acct 217) Shares (g) | Held by Respondent As Reacquired Stock (Acct 217) Cost (h) | Held by Respondent In Sinking and Other Funds Shares (i) | Held by Respondent In Sinking and Other Funds Amount (j) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Common Stock (Account 201) | | | | | | | | | |
| 2 | No Par Value | 200,000,000 | | | 82,193,000 | 1,748,263,267 | | | | |
| 3 | Restricted Shares | | | | | | | | 190,979 | 6,989,444 |
| 11 | Total | 200,000,000 | | | 82,193,000 | 1,748,263,267 | | | | |
| 12 | Preferred Stock (Account 204) | | | | | | | | | |
| 13 | Cumulative | 10,000,000 | | | | | | | | |
| 16 | Total | 10,000,000 | | | 0 | 0 | | | | |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 2026-04-17 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

**Other Paid-in Capital**

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

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

| Line No. | Item (a) | Amount (b) |
|---|---|---|
| 1 | **Donations Received from Stockholders (Account 208)** | |
| 2 | Beginning Balance Amount | |
| 3 | Increases (Decreases) from Sales of Donations Received from Stockholders | |
| 4 | Ending Balance Amount | 0 |
| 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 | 0 |
| 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 | 0 |
| 13 | **Miscellaneous Paid-In Capital (Account 211)** | |
| 14 | Beginning Balance Amount | (2,732,405) |
| 15 | Increases (Decreases) Due to Miscellaneous Paid-In Capital | |
| 16 | Ending Balance Amount | (2,732,405) |
| 17 | **Other Paid in Capital** | |
| 18 | Beginning Balance Amount | (2,732,405) |
| 19 | Increases (Decreases) in Other Paid-In Capital | |
| 20 | Ending Balance Amount | (2,732,405) |
| 40 | Total | (2,732,405) |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

**CAPITAL STOCK EXPENSE (Account 214)**

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

| Line No. | Class and Series of Stock (a) | Balance at End of Year (b) |
|---|---|---|
| 1 | Common Stock - No Par | (59,877,267) |
| 22 | TOTAL | (59,877,267) |
| | | |

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

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

| Line No. | Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a) | Related Account Number (b) | Principal Amount of Debt Issued (c) | Total Expense, Premium or Discount (d) | Total Expense (e) | Total Premium (f) | Total Discount (g) | Nominal Date of Issue (h) | Date of Maturity (i) | AMORTIZATION PERIOD Date From (j) | AMORTIZATION PERIOD Date To (k) | Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l) | Interest for Year Amount (m) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Bonds (Account 221) | | | | | | | | | | | | |
| 2 | FMBS - SERIES C - 6.37% DUE 06/18/2028 | 221300 | 25,000,000 | | 158,304 | | | 06/19/1998 | 06/19/2028 | 06/19/1998 | 06/19/2028 | 25,000,000 | 1,592,500 |
| 3 | FMBS - 6.25% DUE 12-01-35 | 221400 | 150,000,000 | | 1,812,935 | | 900,500 | 11/17/2005 | 12/01/2035 | 11/17/2005 | 12/01/2035 | 150,000,000 | 9,375,000 |
| 4 | FMBS - 5.70% DUE 07-01-2037 | 221420 | 150,000,000 | | 4,702,304 | | 222,000 | 12/15/2006 | 07/01/2037 | 12/15/2006 | 07/01/2037 | 150,000,000 | 8,550,000 |
| 5 | 5.55% SERIES DUE 12-20-2040 | 221540 | 35,000,000 | | 258,834 | | | 12/20/2010 | 12/20/2040 | 12/20/2010 | 12/20/2040 | 35,000,000 | 1,942,500 |
| 6 | 4.45% SERIES DUE 12-14-2041 | 221560 | 85,000,000 | | 692,833 | | | 12/14/2011 | 12/14/2041 | 12/14/2011 | 12/14/2041 | 85,000,000 | 3,782,500 |
| 7 | 4.11% SERIES DUE 12-1-2044 | 221610 | 60,000,000 | | 428,205 | | | 12/18/2014 | 12/01/2044 | 12/18/2014 | 12/01/2044 | 60,000,000 | 2,466,000 |
| 8 | 4.37% SERIES DUE 12-1-2045 | 221620 | 100,000,000 | | 590,761 | | | 12/16/2015 | 12/01/2045 | 12/16/2015 | 12/01/2045 | 100,000,000 | 4,370,000 |
| 9 | 4.23% SERIES DUE 11-29-2047 | 221580 | 80,000,000 | | 730,833 | | | 11/30/2012 | 11/29/2047 | 11/30/2012 | 11/29/2047 | 80,000,000 | 3,384,000 |
| 10 | 3.91% SERIES DUE 12-1-2047 | 221640 | 90,000,000 | | 552,539 | | | 12/14/2017 | 12/01/2047 | 12/14/2017 | 12/01/2047 | 90,000,000 | 3,519,000 |
| 11 | 4.35% SERIES DUE 6-1-2048 | 221650 | 375,000,000 | | 4,246,448 | | 378,750 | 05/22/2018 | 06/01/2048 | 05/22/2018 | 06/01/2048 | 375,000,000 | 16,312,500 |
| 12 | 3.43% SERIES DUE 12-1-2049 | 221660 | 180,000,000 | | 1,108,340 | | | 11/26/2019 | 12/01/2049 | 11/26/2019 | 12/01/2049 | 180,000,000 | 6,174,000 |
| 13 | 3.07% SERIES DUE 9-1-2050 | 221670 | 165,000,000 | | 1,074,990 | | | 09/30/2020 | 09/30/2050 | 09/30/2020 | 09/30/2050 | 165,000,000 | 5,065,500 |
| 14 | 2.90% SERIES DUE 10/01/2051 | 221680 | 140,000,000 | | 1,083,452 | | | 09/28/2021 | 10/01/2051 | 09/28/2021 | 10/01/2051 | 140,000,000 | 4,060,000 |
| 15 | 3.54% SERIES DUE 2051 | 221630 | 175,000,000 | | 1,042,569 | | | 12/15/2016 | 12/01/2051 | 12/15/2016 | 12/01/2051 | 175,000,000 | 6,195,000 |
| 16 | 4.00% SERIES DUE 4/1/2052 | 221690 | 400,000,000 | | 4,579,993 | | 144,000 | 03/17/2022 | 04/01/2052 | 03/17/2022 | 04/01/2052 | 400,000,000 | 16,000,000 |
| 17 | 5.66% SERIES DUE 04-01-2053 | 221710 | 250,000,000 | | 1,444,302 | | | 03/29/2023 | 04/01/2053 | 03/29/2023 | 04/01/2053 | 250,000,000 | 14,150,000 |
| 18 | 6.18% SERIES DUE 07-01-2055 | 221720 | 120,000,000 | | 1,077,479 | | | 07/23/2025 | 07/01/2055 | 07/23/2025 | 07/01/2055 | 120,000,000 | 3,269,419 |
| 19 | COLSTRIP 2010A PCRBs DUE 2032 | 221350 | 66,700,000 | | 965,638 | | | 04/01/2024 | 10/01/2032 | 04/01/2024 | 10/01/2032 | 66,700,000 | 2,584,625 |
| 20 | COLSTRIP 2010B PCRBs DUE 2034 | 221360 | 17,000,000 | | 264,090 | | | 04/01/2024 | 03/01/2034 | 04/01/2024 | 03/01/2034 | 17,000,000 | 658,750 |
| 21 | Subtotal | | 2,663,700,000 | | 26,814,849 | 0 | 1,645,250 | | | | | 2,663,700,000 | 113,451,294 |
| 22 | Reacquired Bonds (Account 222) | | | | | | | | | | | | |
| 23 | | | | | | | | | | | | | |
| 24 | | | | | | | | | | | | | |
| 25 | | | | | | | | | | | | | |
| 26 | Subtotal | | | | | | | | | | | 0 | |
| 27 | Advances from Associated Companies (Account 223) | | | | | | | | | | | | |
| 28 | ADVANCE ASSOCIATED AVISTA CAPITAL II (ToPRS) | 223011 | 51,547,000 | | 1,296,086 | | | 03/19/2006 | 06/01/2037 | 03/19/2006 | 06/01/2037 | 51,547,000 | 2,192,351 |
| 29 | Subtotal | | 51,547,000 | | 1,296,086 | 0 | 0 | | | | | 51,547,000 | 2,192,351 |
| 30 | Other Long Term Debt (Account 224) | | | | | | | | | | | | |
| 31 | | | | | | | | | | | | | |
| 32 | | | | | | | | | | | | | |
| 33 | | | | | | | | | | | | | |
| 34 | Subtotal | | | | | | | | | | | 0 | |
| 33 | TOTAL | | 2,715,247,000 | | | | | | | | | 2,715,247,000 | 115,643,645 |

| Name of Respondent:<br>Avista Corporation | This report is:<br>(1) ☑ An Original<br>(2) ☐ A Resubmission | Date of Report:<br>04/17/2026 | Year/Period of Report<br>End of: 2025/ Q4 |
|---|---|---|---|

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

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

| Line No. | Particulars (Details)<br>(a) | Amount<br>(b) |
|---|---|---|
| 1 | Net Income for the Year (Page 117) | 192,916,846 |
| 2 | Reconciling Items for the Year | |
| 3 | | |
| 4 | Taxable Income Not Reported on Books | |
| 5 | Contributions in Aid of Construction | 24,352,770 |
| 6 | Other | 72,042,464 |
| 9 | Deductions Recorded on Books Not Deducted for Return | |
| 10 | Book Depreciation | 283,601,733 |
| 11 | Federal Income Tax Expense | 24,462,924 |
| 12 | State Income Tax Expense | (31,461) |
| 13 | Subsidiary Overheads | 1,070,227 |
| 14 | Other | 67,400,453 |
| 14 | Income Recorded on Books Not Included in Return | |
| 15 | Subsidiary Earnings | (7,141,006) |
| 16 | Other | 24,023,313 |
| 19 | Deductions on Return Not Charged Against Book Income | |
| 20 | Tax Depreciation | 313,918,386 |
| 21 | Plant Basis Adjustment | 109,775,071 |
| 22 | Other | 113,292,897 |
| 27 | Federal Tax Net Income | 111,947,294 |
| 28 | Show Computation of Tax: | |
| 29 | Federal Tax @ 21% | 23,508,932 |
| 30 | Business Credits Utilized | (8,842,207) |
| 31 | Prior Year True Ups | 2,826,223 |
| 32 | Uncertain Tax Benefit | 3,589,748 |
| 33 | Total Federal Current Tax Expense | 21,082,696 |

| Name of Respondent:<br>Avista Corporation | This report is:<br>(1) ☑ An Original<br>(2) ☐ A Resubmission | Date of Report:<br>04/17/2026 | Year/Period of Report<br>End of: 2025/ Q4 |
|---|---|---|---|

## TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

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

| Line No. | Kind of Tax (See Instruction 5) (a) | Type of Tax (b) | State (c) | Tax Year (d) | BALANCE AT BEGINNING OF YEAR | | Taxes Charged During Year (g) | Taxes Paid During Year (h) | Adjustments (i) | BALANCE AT END OF YEAR | | DISTRIBUTION OF TAXES CHARGED | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Taxes Accrued (Account 236) (e) | Prepaid Taxes (Include in Account 165) (f) | | | | Taxes Accrued (Account 236) (j) | Prepaid Taxes (Included in Account 165) (k) | Electric (Account 408.1, 409.1) (l) | Extraordinary Items (Account 409.3) (m) | Adjustment to Ret. Earnings (Account 439) (n) | Other (o) |
| 1 | Income Tax | Federal Tax | | 2020 | | | | (76,459) | (76,459) | 0 | | | | | |
| 2 | Income Tax | Federal Tax | | 2021 | | | 276,731 | 161,814 | (114,917) | 0 | | 193,702 | | | 83,029 |
| 3 | Income Tax | Federal Tax | | 2022 | | | 365,767 | | (365,767) | 0 | | 262,617 | | | 103,150 |
| 4 | Income Tax | Federal Tax | | 2023 | | | 883,941 | | (883,941) | 0 | | 634,661 | | | 249,280 |
| 5 | Income Tax | Federal Tax | | 2024 | | | 3,622,310 | 2,615,887 | (1,006,423) | 0 | | 2,032,315 | | | 1,589,995 |
| 6 | Income Tax | Federal Tax | | 2025 | | | 15,709,199 | 24,649,000 | 8,939,801 | 0 | | (346,105) | | | 16,055,304 |
| 7 | **Subtotal Federal Tax** | | | | 0 | 0 | 20,857,948 | 27,350,242 | 6,492,294 | 0 | 0 | 2,777,190 | 0 | 0 | 18,080,758 |
| 8 | Property Tax | Property Tax | WA | 2024 | 14,250,328 | | 206,652 | 14,456,980 | | 0 | | 132,074 | | | 74,578 |
| 9 | Property Tax | Property Tax | WA | 2025 | | | 16,595,761 | 505 | | 16,595,256 | | 12,753,036 | | | 3,842,725 |
| 10 | Property Tax | Property Tax | ID | 2024 | 1,928,042 | | | 1,928,042 | | 0 | | | | | |
| 11 | Property Tax | Property Tax | ID | 2025 | | | 4,537,249 | 2,298,114 | | 2,239,135 | | 3,558,096 | | | 979,153 |
| 12 | Property Tax | Property Tax | MT | 2024 | 3,240,799 | | 253 | 3,241,051 | (1) | 0 | | 253 | | | |
| 13 | Property Tax | Property Tax | MT | 2025 | | | 6,246,672 | 3,139,770 | 2 | 3,106,904 | | 6,246,672 | | | |
| 14 | Property Tax | Property Tax | OR | 2024 | | 4,001,236 | 4,001,236 | | | 0 | | 1,609,145 | | | 2,392,091 |
| 15 | Property Tax | Property Tax | OR | 2025 | | | 4,283,564 | 8,567,484 | | 0 | 4,283,920 | 2,020,531 | | | 2,263,033 |
| 16 | **Subtotal Property Tax** | | | | 19,419,169 | 4,001,236 | 35,871,387 | 33,631,946 | 1 | 21,941,295 | 4,283,920 | 26,319,807 | 0 | 0 | 9,551,580 |
| 17 | Excise Tax | Excise Tax | WA | 2018 | 164,708 | | (249,576) | (84,868) | | 0 | | (249,576) | | | 0 |
| 18 | Excise Tax | Excise Tax | WA | 2019 | 1,789,049 | | (256,486) | 1,532,563 | | 0 | | (256,486) | | | 0 |
| 19 | Excise Tax | Excise Tax | WA | 2020 | 169,866 | | (196,066) | (26,200) | | 0 | | (196,066) | | | 0 |
| 20 | Excise Tax | Excise Tax | WA | 2021 | (64,551) | | (286,626) | (351,177) | | 0 | | (231,335) | | | (55,291) |
| 21 | Excise Tax | Excise Tax | WA | 2022 | | | (413,445) | | | (413,445) | | (413,445) | | | 0 |
| 22 | Excise Tax | Excise Tax | WA | 2023 | | | (415,377) | | | (415,377) | | (415,377) | | | 0 |
| 23 | Excise Tax | Excise Tax | WA | 2024 | 4,182,874 | | (791,362) | 4,167,996 | | (776,484) | | (820,418) | | | 29,056 |
| 24 | Excise Tax | Excise Tax | WA | 2025 | | | 40,223,691 | 36,462,935 | | 3,760,756 | | 30,375,644 | | | 9,848,047 |
| 25 | Corp Activities Tax-CAT | Excise Tax | OR | 2024 | | | (236,042) | | 236,042 | 0 | | | | | (236,042) |
| 26 | Corp Activities Tax-CAT | Excise Tax | OR | 2025 | | | 1,000,000 | 1,000,000 | | 0 | | | | | 1,000,000 |
| 27 | **Subtotal Excise Tax** | | | | 6,241,946 | 0 | 38,378,711 | 42,701,249 | 236,042 | 2,155,450 | 0 | 27,792,941 | 0 | 0 | 10,585,770 |
| 28 | Natural Gas Use Tax | Sales And Use Tax | WA | 2024 | 84 | | 615 | 699 | | 0 | | 615 | | | |
| 29 | Natural Gas Use Tax | Sales And Use Tax | WA | 2025 | | | 111,388 | 108,028 | | 3,360 | | 3,219 | | | 108,169 |
| 30 | Use Tax | Sales And Use Tax | WA | 2018 | (174,420) | | | (174,420) | | 0 | | | | | |
| 31 | Use Tax | Sales And Use Tax | WA | 2019 | (381,322) | | (76,543) | (457,865) | | 0 | | | | | (76,543) |
| 32 | Use Tax | Sales And Use Tax | WA | 2020 | (625,368) | | | (625,368) | | 0 | | | | | |
| 33 | Use Tax | Sales And Use Tax | WA | 2021 | (335,436) | | | (335,436) | | 0 | | | | | |
| 34 | Use Tax | Sales And Use Tax | WA | 2022 | | | (137,469) | | | (137,469) | | | | | (137,469) |
| 35 | Use Tax | Sales And Use Tax | WA | 2023 | | | (123,314) | | | (123,314) | | | | | (123,314) |
| 36 | Use Tax | Sales And Use Tax | WA | 2024 | 606,933 | | (186,642) | 606,933 | | (186,642) | | | | | (186,642) |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 37 | Use Tax | Sales And Use Tax | WA | 2025 | | | 2,551,943 | 2,249,835 | | 302,108 | | | | | 2,551,943 |
| 38 | Use Tax | Sales And Use Tax | ID | 2024 | 53,651 | | | 53,650 | (1) | 0 | | | | | |
| 39 | Use Tax | Sales And Use Tax | ID | 2025 | | | 228,733 | 190,092 | 1 | 38,642 | | | | | 228,733 |
| 40 | **Subtotal Sales And Use Tax** | | | | (855,878) | 0 | 2,368,711 | 1,616,148 | 0 | (103,315) | 0 | 3,834 | 0 | 0 | 2,364,877 |
| 41 | Municipal Occupation Tax | Local Tax | WA | 2024 | 4,132,325 | | (2,692) | 4,129,633 | | 0 | | (2,111) | | | (581) |
| 42 | Municipal Occupation Tax | Local Tax | WA | 2025 | | | 33,827,830 | 29,677,924 | | 4,149,906 | | 25,049,994 | | | 8,777,836 |
| 43 | **Subtotal Local Tax** | | | | 4,132,325 | 0 | 33,825,138 | 33,807,557 | 0 | 4,149,906 | 0 | 25,047,883 | 0 | 0 | 8,777,255 |
| 44 | KWH Tax | Other Taxes | ID | 2024 | 18,218 | | 7,978 | 26,235 | 39 | 0 | | 7,978 | | | |
| 45 | KWH Tax | Other Taxes | ID | 2025 | | | 364,696 | 311,851 | (37) | 52,808 | | 364,696 | | | |
| 46 | KWH Tax | Other Taxes | MT | 2024 | 219,557 | | | 219,557 | | 0 | | | | | |
| 47 | KWH Tax | Other Taxes | MT | 2025 | | | 960,583 | 717,431 | | 243,152 | | 960,583 | | | |
| 48 | WA Renewable Energy Credits | Other Taxes | WA | 2024 | | | (6,305,318) | (6,305,318) | | 0 | | | | | (6,305,318) |
| 49 | WA Renewable Energy Credits | Other Taxes | WA | 2025 | | | (2,808,193) | (2,221,213) | | (586,980) | | | | | (2,808,193) |
| 50 | **Subtotal Other Taxes** | | | | 237,775 | 0 | (7,780,254) | (7,251,457) | 2 | (291,020) | 0 | 1,333,257 | 0 | 0 | (9,113,511) |
| 51 | Income Tax | State Tax | ID | 2024 | | | | | | 0 | | | | | |
| 52 | Income Tax | State Tax | ID | 2025 | | | 120 | 120 | | 0 | | 102 | | | 18 |
| 53 | Income Tax | State Tax | MT | 2024 | | | | | | 0 | | | | | |
| 54 | Income Tax | State Tax | MT | 2025 | | | 50 | 50 | | 0 | | 50 | | | |
| 55 | Income Tax | State Tax | OR | 2024 | | | | | | 0 | | | | | |
| 56 | Income Tax | State Tax | OR | 2025 | | | 100,000 | 100,000 | | 0 | | 20,000 | | | 80,000 |
| 57 | Income Tax | State Tax | Misc | 2024 | | | 720 | 1,000 | 280 | 0 | | 515 | | | 205 |
| 58 | Income Tax | State Tax | Misc | 2025 | | | 1,975 | 1,975 | | 0 | | 844 | | | 1,131 |
| 59 | **Subtotal State Tax** | | | | 0 | 0 | 102,865 | 103,145 | 280 | 0 | 0 | 21,511 | 0 | 0 | 81,354 |
| 60 | Payroll Taxes | Payroll Tax | WA | 2024 | 520,144 | | | 108,733 | (411,411) | 0 | | | | | 0 |
| 61 | Payroll Taxes | Payroll Tax | ID | 2025 | | | 51,450 | 48,775 | | 2,675 | | 19,167 | | | 32,283 |
| 62 | Payroll Taxes | Payroll Tax | MT | 2024 | 134 | | | 134 | | 0 | | | | | |
| 63 | Payroll Taxes | Payroll Tax | MT | 2025 | | | 5,737 | 5,598 | | 139 | | 2,137 | | | 3,600 |
| 64 | Payroll Taxes | Payroll Tax | OR | 2024 | 11,265 | | | 7,370 | (3,895) | 0 | | | | | |
| 65 | Payroll Taxes | Payroll Tax | OR | 2025 | | | 78,700 | 65,370 | | 13,330 | | 29,318 | | | 49,382 |
| 66 | Payroll Taxes | Payroll Tax | ID | 2024 | 20,391 | | | 3,218 | (17,173) | 0 | | | | | |
| 67 | Payroll Taxes | Payroll Tax | WA | 2025 | | | 1,360,047 | 1,055,682 | | 304,365 | | 506,655 | | | 853,392 |
| 68 | Payroll Taxes | Payroll Tax | MISC | 2024 | 50 | | | | (50) | 0 | | | | | 0 |
| 69 | Payroll Taxes | Payroll Tax | MISC | 2025 | | | 2,579 | 2,032 | | 547 | | 961 | | | 1,618 |
| 70 | Payroll Taxes | Payroll Tax | FED | 2024 | 769,400 | | 2,022,133 | | (2,791,534) | (1) | | 753,301 | | | 1,268,832 |
| 71 | Payroll Taxes | Payroll Tax | FED | 2025 | | | 19,546,052 | 20,468,148 | 3,224,064 | 2,301,968 | | 7,281,448 | | | 12,264,604 |
| 72 | **Subtotal Payroll Tax** | | | | 1,321,384 | 0 | 23,066,698 | 21,765,060 | 1 | 2,623,023 | 0 | 8,592,987 | 0 | 0 | 14,473,711 |
| 73 | Franchise Tax | Franchise Tax | OR | 2025 | | | 5,351,878 | 3,974,076 | | 1,377,802 | | | | | 5,351,878 |
| 74 | Franchise Tax | Franchise Tax | ID | 2024 | 1,282,960 | | 874 | 1,283,834 | | 0 | | 605 | | | 269 |
| 75 | Franchise Tax | Franchise Tax | ID | 2025 | | | 5,683,274 | 4,376,971 | (1) | 1,306,302 | | 4,276,599 | | | 1,406,675 |
| 76 | Franchise Tax | Franchise Tax | OR | 2024 | 1,461,532 | | (39,925) | 1,421,608 | 1 | 0 | | | | | (39,925) |
| 77 | **Subtotal Franchise Tax** | | | | 2,744,492 | 0 | 10,996,101 | 11,056,489 | 0 | 2,684,104 | 0 | 4,277,204 | 0 | 0 | 6,718,897 |
| 78 | Consumer Council Fee | Other License And Fees Tax | MT | 2024 | 10 | | | 8 | (2) | 0 | | | | | |
| 79 | Consumer Council Fee | Other License And Fees Tax | MT | 2025 | | | 43 | 39 | | 4 | | 43 | | | |
| 80 | Public Comission Fee | Other License And Fees Tax | MT | 2024 | 46 | | | 45 | (1) | 0 | | | | | |
| 81 | Public Comission Fee | Other License And Fees Tax | MT | 2025 | | | 246 | 214 | 1 | 33 | | 246 | | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 82 | **Subtotal Other License And Fees Tax** | | | | 56 | 0 | 289 | 306 | (2) | 37 | 0 | 289 | 0 | 0 | 0 |
| 40 | TOTAL | | | | 33,241,269 | 4,001,236 | 157,687,594 | 164,780,685 | 6,728,618 | 33,159,480 | 4,283,920 | 96,166,903 | 0 | 0 | 61,520,691 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

| Line No. | Account Subdivisions (a) | Balance at Beginning of Year (b) | Deferred for Year | | Allocations to Current Year's Income | | Adjustments (g) | Balance at End of Year (h) | Average Period of Allocation to Income (i) | ADJUSTMENT EXPLANATION (j) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Account No. (c) | Amount (d) | Account No. (e) | Amount (f) | | | | |
| 1 | Electric Utility | | | | | | | | | |
| 2 | 3% | | | | | | | | | |
| 3 | 10% | | | | | | | | | |
| 4 | Fed ITC | 26,997,443 | 411.4 | 0 | 411.4 | 789,920 | | 26,207,523 | | |
| 5 | Idaho ITC | 933,875 | 411.4 | 53 | 411.4 | 26,512 | | 907,416 | | |
| 8 | TOTAL Electric (Enter Total of lines 2 thru 7) | 27,931,318 | | 53 | | 816,432 | 0 | 27,114,939 | | |
| 9 | Other (List separately and show 3%, 4%, 7%, 10% and TOTAL) | | | | | | | | | |
| 10 | Gas Property (100% | | | | | | | | | |
| 11 | Idaho ITC | 166,501 | 411.4 | 7 | 411.4 | 4,729 | | 161,779 | | |
| 47 | OTHER TOTAL | 166,501 | | 7 | | 4,729 | 0 | 161,779 | | |
| 48 | GRAND TOTAL | 28,097,819 | | | | | | 27,276,718 | | |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

**OTHER DEFERRED CREDITS (Account 253)**

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

| Line No. | Description and Other Deferred Credits (a) | Balance at Beginning of Year (b) | DEBITS Contra Account (c) | DEBITS Amount (d) | Credits (e) | Balance at End of Year (f) |
|---|---|---|---|---|---|---|
| 1 | [(a)] Deferred Gas Exchange | 1,406,250 | 495 | 9,562,500 | 10,875,000 | 2,718,750 |
| 2 | Bills Pole Rentals | 734,286 | 454 | 3,002,362 | 3,040,883 | 772,807 |
| 3 | Defer Comp Active Execs | 9,380,300 | 128 | 1,160,335 | 1,176,331 | 9,396,296 |
| 4 | Unbilled Revenue | 10,317,153 | 908 | 93,062,543 | 94,090,841 | 11,345,451 |
| 5 | [(b)] Decoupling Deferred Credits | 0 | | 0 | 5,559,177 | 5,559,177 |
| 6 | [(c)] Reg Liability-COVID-19 Deferral | 8,358,455 | 407, 236 | 5,468,478 | 1,772,159 | 4,662,136 |
| 7 | [(d)] WA REC Deferrals | 1,140,423 | 186, 431, 557 | 2,106,713 | 966,290 | 0 |
| 8 | Timber Harvest | 226,796 | | 0 | 0 | 226,796 |
| 9 | Other Derf Cr - FISERV | 858,333 | 903 | 158,333 | 0 | 700,000 |
| 10 | [(e)] Accts Pay - Software Licenses - LT | 1,205,283 | 242 | 2,122,157 | 3,681,428 | 2,764,554 |
| 11 | Misc. Deferred Credits | 78,143 | 407, 186 | 789,622 | 1,226,642 | 515,163 |
| 12 | Pledges - LT | 0 | 426 | 100,000 | 500,000 | 400,000 |
| 13 | Prepaid Project Billings | 0 | | 0 | 588,382 | 588,382 |
| 47 | TOTAL | 33,705,422 | | 117,533,043 | 123,477,133 | 39,649,512 |

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 2028.

(b) Concept: DescriptionOfOtherDeferredCredits

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

Deferred Liability for Software Licenses

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

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

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

| Line No. | Account (a) | Balance at Beginning of Year (b) | CHANGES DURING YEAR Amounts Debited to Account 410.1 (c) | Amounts Credited to Account 411.1 (d) | Amounts Debited to Account 410.2 (e) | Amounts Credited to Account 411.2 (f) | ADJUSTMENTS Debits Account Credited (g) | Debits Amount (h) | Credits Account Debited (i) | Credits Amount (j) | Balance at End of Year (k) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Account 282 | | | | | | | | | | |
| 2 | Electric | 440,316,609 | 9,425,031 | 0 | | | | | 182.3 | 2,952,734 | 452,694,374 |
| 3 | Gas | 162,339,298 | 415,475 | 0 | | | 182.3 | 392,413 | | | 162,362,360 |
| 4 | Other (Specify) | 54,671,999 | 8,227,001 | 28,358 | | | | | 182.3 | 128,684 | 62,999,326 |
| 5 | Total (Total of lines 2 thru 4) | 657,327,906 | 18,067,507 | 28,358 | 0 | 0 | | 392,413 | | 3,081,418 | 678,056,060 |
| 6 | | | | | | | | | | | 0 |
| 7 | | | | | | | | | | | 0 |
| 8 | | | | | | | | | | | 0 |
| 9 | TOTAL Account 282 (Total of Lines 5 thru 8) | 657,327,906 | 18,067,507 | 28,358 | 0 | 0 | | 392,413 | | 3,081,418 | 678,056,060 |
| 10 | Classification of TOTAL | | | | | | | | | | |
| 11 | Federal Income Tax | 657,327,906 | 18,067,507 | 28,358 | | | | 392,413 | | 3,081,418 | 678,056,060 |
| 12 | State Income Tax | | | | | | | | | | 0 |
| 13 | Local Income Tax | | | | | | | | | | 0 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Provide in the space below explanations for Page 276. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

| Line No. | Account (a) | Balance at Beginning of Year (b) | CHANGES DURING YEAR | | | | ADJUSTMENTS | | | | Balance at End of Year (k) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | Debits | | Credits | | |
| | | | Amounts Debited to Account 410.1 (c) | Amounts Credited to Account 411.1 (d) | Amounts Debited to Account 410.2 (e) | Amounts Credited to Account 411.2 (f) | Account Credited (g) | Amount (h) | Account Debited (i) | Amount (j) | |
| 1 | Account 283 | | | | | | | | | | |
| 2 | Electric | | | | | | | | | | |
| 3 | Electric | 51,095,724 | 1,528,659 | (11,025,198) | 451,420 | 164,781 | | | 182/254 | 1,371,360 | 65,307,580 |
| 9 | TOTAL Electric (Total of lines 3 thru 8) | 51,095,724 | 1,528,659 | (11,025,198) | 451,420 | 164,781 | | 0 | | 1,371,360 | 65,307,580 |
| 10 | Gas | | | | | | | | | | |
| 11 | Gas | 1,742,708 | 117,833 | (1,228,752) | (339,257) | (366,069) | | | 182/254 | 16,055,505 | 19,171,610 |
| 17 | TOTAL Gas (Total of lines 11 thru 16) | 1,742,708 | 117,833 | (1,228,752) | (339,257) | (366,069) | | 0 | | 16,055,505 | 19,171,610 |
| 18 | TOTAL Other | 173,606,452 | 2,243,334 | 1,258,551 | 74,014 | 0 | 182/254 | 12,353,466 | | | 162,311,783 |
| 19 | TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18) | 226,444,884 | 3,889,826 | (10,995,399) | 186,177 | (201,288) | | 12,353,466 | | 17,426,865 | 246,790,973 |
| 20 | Classification of TOTAL | | | | | | | | | | |
| 21 | Federal Income Tax | 226,444,884 | 3,889,826 | (10,995,399) | 186,177 | (201,288) | | 12,353,466 | | 17,426,865 | 246,790,973 |
| 22 | State Income Tax | | | | | | | | | | 0 |
| 23 | Local Income Tax | | | | | | | | | | 0 |

NOTES

| Name of Respondent:<br>Avista Corporation | This report is:<br>(1) ☑ An Original<br>(2) ☐ A Resubmission | Date of Report:<br>04/17/2026 | Year/Period of Report<br>End of: 2025/ Q4 |
|---|---|---|---|

**OTHER REGULATORY LIABILITIES (Account 254)**

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

| Line No. | Description and Purpose of Other Regulatory Liabilities (a) | Balance at Beginning of Current Quarter/Year (b) | DEBITS Account Credited (c) | DEBITS Amount (d) | Credits (e) | Balance at End of Current Quarter/Year (f) |
|---|---|---|---|---|---|---|
| 1 | [(a)] Idaho Investment Tax Credit | 11,417,527 | 190 | 8,289 | 2,901,989 | 14,311,227 |
| 2 | [(b)] Interest Rate Swaps | 24,240,346 | 175, 427 | 2,384,171 | 1,104,000 | 22,960,175 |
| 3 | Nez Perce | 418,268 | 557 | 22,008 | 0 | 396,260 |
| 4 | Idaho Earnings Test | 228,990 | 407 | 228,990 | 0 | 0 |
| 5 | [(c)] Decoupling Rebate | 5,444,701 | 495, 182 | 5,815,427 | 370,726 | 0 |
| 6 | [(d)] Deferred Federal ITC - Varies | 6,999,535 | 190 | 204,690 | 0 | 6,794,845 |
| 7 | [(e)] Plant Excess Deferred | 287,674,198 | 190, 282 | 13,945,030 | 0 | 273,729,168 |
| 8 | [(f)] DSM Tariff Rider | 1,805,673 | | 0 | 699,926 | 2,505,599 |
| 9 | [(g)] Low Income Energy Assistance | 5,162,615 | 242, 908 | 405,104 | 5,385,719 | 10,143,230 |
| 10 | [(h)] Reg Liability - OR Tax Strategy Deferral | 98,870 | | 0 | 5,223 | 104,093 |
| 11 | [(i)] Reg Liability - COVID-19 Deferral | 1,475,802 | 407 | 1,114,012 | 102,202 | 463,992 |
| 12 | [(j)] Reg Liability - Tax Customer Credit | 34,974,271 | 410, 190 | 12,200,553 | 6,787,316 | 29,561,034 |
| 13 | [(k)] CS2 Insurance Proceeds Deferral | 943,893 | 407 | 511,542 | 0 | 432,351 |
| 14 | [(l)] Other Regulatory Liabilities | 10,109,166 | 190 | 3,812,355 | 0 | 6,296,811 |
| 15 | [(m)] Reg Liability - CCA | 43,799,427 | 407 | 52,662,549 | 42,726,511 | 33,863,389 |
| 16 | Depreciation Regulatory Liability | 2,732,550 | 407 | 1,129,450 | 1,237,555 | 2,840,655 |
| 17 | Idaho PCA Deferral | 14,912,036 | 557 | 16,493,322 | 6,229,130 | 4,647,844 |
| 18 | Battery Storage ITC | 177,001 | 190 | 5,289 | 0 | 171,712 |
| 19 | Board of Director Fees Rate | 0 | | 0 | 671,246 | 671,246 |
| 20 | [(o)] BPA RES Exchange Regulatory Liability | 0 | | 0 | 626,275 | 626,275 |
| 21 | [(p)] Misc. Regulatory Liabilities | 49,450 | Various | 748,784 | 745,404 | 46,070 |
| 41 | TOTAL | 452,664,319 | | 111,691,565 | 69,593,222 | 410,565,976 |

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 |
| Noxon ITC - 65yr amort, ends 2077<br>Community Solar ITC - 20yr amort, ends 2035<br>Nine Mile ITC - 65yr amort, ends 2080. |
| (e) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities |
| Amortized over remaining book life of plant, estimated 36 years. |
| (f) 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. |
| (g) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities |
| WA Docket No UE-190912, UG-190920<br>ID Docket No AVU-E-18-12, AVU-G-18-08<br>OR RG 81, Docket No ADV 1063 (Advice No. 19-10-G) |
| (h) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities |
| OR Docket No UM 2124. Deferral of associated state tax savings. |
| (i) 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. |
| (j) 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.<br>Accounting method change for federal income tax from normalization flow-through for Industry Director Directive No. 5 mixed service costs and meters. |
| (k) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities |
| Insurance proceeds for failed transformer at Coyote Springs per WA Order UE-210893 Order 01. |
| (l) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities |
| State NOL Carryforward Flow Through. |
| (m) 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. |
| (n) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities |
| Refers to Rider 59-Residential and Farm Energy Rate adjustment resulting from an agreement between Avista and Bonneville Power Administration covering Residential Exchange Program benefits. |
| (o) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities |
| Grouped minor items. |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## Electric Operating Revenues

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.
6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

| Line No. | Title of Account (a) | Operating Revenues Year to Date Quarterly/Annual (b) | Operating Revenues Previous year (no Quarterly) (c) | MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d) | MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e) | AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f) | AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g) |
|---|---|---|---|---|---|---|---|
| 1 | Sales of Electricity | | | | | | |
| 2 | (440) Residential Sales | 550,171,226 | 473,446,187 | 4,113,836 | 4,017,618 | 376,349 | 371,076 |
| 3 | (442) Commercial and Industrial Sales | | | | | | |
| 4 | Small (or Comm.) (See Instr. 4) | 402,390,141 | 369,033,306 | 3,215,706 | 3,166,267 | 45,959 | 45,794 |
| 5 | Large (or Ind.) (See Instr. 4) | 159,472,031 | 145,879,427 | 2,395,469 | 2,195,428 | 1,159 | 1,175 |
| 6 | (444) Public Street and Highway Lighting | 9,464,778 | 8,819,256 | 14,756 | 16,978 | 761 | 739 |
| 7 | (445) Other Sales to Public Authorities | | | | | | |
| 8 | (446) Sales to Railroads and Railways | | | | | | |
| 9 | (448) Interdepartmental Sales | 2,215,615 | 1,993,992 | 17,079 | 16,560 | 182 | 179 |
| 10 | TOTAL Sales to Ultimate Consumers | 1,123,713,791 | 999,172,168 | 9,756,846 | 9,412,851 | 424,410 | 418,963 |
| 11 | (447) Sales for Resale | 191,474,612 | 231,161,008 | 4,554,075 | 3,788,593 | | |
| 12 | TOTAL Sales of Electricity | 1,315,188,403 | 1,230,333,176 | 14,310,921 | 13,201,444 | 424,410 | 418,963 |
| 13 | (Less) (449.1) Provision for Rate Refunds | 9,401,186 | | | | | |
| 14 | TOTAL Revenues Before Prov. for Refunds | 1,305,787,217 | 1,230,333,176 | 14,310,921 | 13,201,444 | 424,410 | 418,963 |
| 15 | Other Operating Revenues | | | | | | |
| 16 | (450) Forfeited Discounts | | | | | | |
| 17 | (451) Miscellaneous Service Revenues | 259,726 | 164,999 | | | | |
| 18 | (453) Sales of Water and Water Power | 415,660 | 586,004 | | | | |
| 19 | (454) Rent from Electric Property | 7,097,761 | 6,261,512 | | | | |
| 20 | (455) Interdepartmental Rents | | | | | | |
| 21 | (456) Other Electric Revenues | 29,999,697 | 53,721,330 | | | | |
| 22 | (456.1) Revenues from Transmission of Electricity of Others | 28,362,803 | 35,825,135 | | | | |
| 23 | (457.1) Regional Control Service Revenues | | | | | | |
| 24 | (457.2) Miscellaneous Revenues | | | | | | |
| 25 | Other Miscellaneous Operating Revenues | | | | | | |
| 26 | TOTAL Other Operating Revenues | 66,135,647 | 96,558,980 | | | | |
| 27 | TOTAL Electric Operating Revenues | 1,371,922,864 | 1,326,892,156 | | | | |

Line12, column (b) includes $ 11,320,349 of unbilled revenues.
Line12, column (d) includes 68,338 MWH relating to unbilled revenues

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
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**SALES OF ELECTRICITY BY RATE SCHEDULES**

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

| Line No. | Number and Title of Rate Schedule (a) | MWh Sold (b) | Revenue (c) | Average Number of Customers (d) | KWh of Sales Per Customer (e) | Revenue Per KWh Sold (f) |
|---|---|---|---|---|---|---|
| 1 | 01 Residential Service | 3,907,345 | 500,610,598 | 355,917 | 10,978.2479 | 0.1281 |
| 2 | 07 Time-of-Use - Residential Service | 2,014 | 251,909 | 126 | 15,985.5317 | 0.1251 |
| 3 | 08 Time-of-Use with Morning Discount - Residential Service | 1,542 | 188,446 | 104 | 14,831.1442 | 0.1222 |
| 4 | 11 General Service | 0 | 87 | 0 | | |
| 5 | 12 Residential & Farm General Service | 109,966 | 18,739,325 | 18,236 | 6,030.1402 | 0.1704 |
| 6 | 22 Residential and Farm Large General Service | 37,701 | 4,379,863 | 60 | 628,349.8333 | 0.1162 |
| 7 | 30 Pumping Service | 41 | 6,782 | 7 | 5,909.5714 | 0.1639 |
| 8 | 32 Residential and Farm Pumping Service | 12,516 | 2,032,981 | 1,899 | 6,590.9336 | 0.1624 |
| 9 | 48 Residential and Farm Area Lighting | 2,771 | 1,551,056 | 0 | | 0.5597 |
| 10 | 58 Tax Adjustment | 0 | 14,569,599 | 0 | | |
| 11 | 95 Optional Renewable Power | 0 | 208,524 | 0 | | |
| 41 | TOTAL Billed Residential Sales | 4,073,896 | 542,539,170 | 376,349 | 10,824.7823 | 0.1332 |
| 42 | TOTAL Unbilled Rev. (See Instr. 6) | 39,940 | 7,632,056 | | | 0.1911 |
| 43 | TOTAL | 4,113,836 | 550,171,226 | 376,349 | 10,930.9072 | 0.1337 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## SALES OF ELECTRICITY BY RATE SCHEDULES

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

| Line No. | Number and Title of Rate Schedule (a) | MWh Sold (b) | Revenue (c) | Average Number of Customers (d) | KWh of Sales Per Customer (e) | Revenue Per KWh Sold (f) |
|---|---|---|---|---|---|---|
| 1 | 11 General Service | 1,495,290 | 179,144,632 | 43,042 | 34,740.2537 | 0.1198 |
| 2 | 13 Optional Commercial Electric Vehicle Rate - General Service | 1,824 | 290,214 | 46 | 39,652.1739 | 0.1591 |
| 3 | 17 Time-of-Use - General Service | 147 | 23,438 | 6 | 24,500 | 0.1594 |
| 4 | 18 Time-of-Use with Morning Discount - General Service | 172 | 27,182 | 10 | 17,200 | 0.158 |
| 5 | 21 Large General Service | 1,211,145 | 158,577,771 | 1,480 | 818,341.2162 | 0.1309 |
| 6 | 23 Optional Commercial Electric Vehicle Rate - Large General Service | 3,519 | 416,482 | 5 | 703,800 | 0.1184 |
| 7 | 25 Extra Large General Service | 346,471 | 28,461,561 | 13 | 26,651,615.3846 | 0.0821 |
| 8 | 31 Pumping Service | 124,047 | 14,814,169 | 1,355 | 91,547.6015 | 0.1194 |
| 9 | 47 Area Light | 3,856 | 2,101,403 | 0 | | 0.545 |
| 10 | 49 Area Lighting | 2,004 | 843,653 | 0 | | 0.421 |
| 11 | 58 Tax Adjustment | 0 | 13,454,623 | 0 | | |
| 12 | 87 Solar Select | | 448,071 | | | |
| 13 | 95 Optional Renewable Power | 0 | 161,896 | 0 | | |
| 14 | I0023 - DCFC-ID | 155 | 26,279 | 2 | 77,500 | 0.1695 |
| 41 | TOTAL Billed Small or Commercial | 3,188,630 | 398,791,374 | 45,959 | 69,379.8821 | 0.1251 |
| 42 | TOTAL Unbilled Rev. Small or Commercial (See Instr. 6) | 27,076 | 3,598,767 | | | 0.1329 |
| 43 | TOTAL Small or Commercial | 3,215,706 | 402,390,141 | 45,959 | 69,969.0159 | 0.1251 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## SALES OF ELECTRICITY BY RATE SCHEDULES

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

| Line No. | Number and Title of Rate Schedule (a) | MWh Sold (b) | Revenue (c) | Average Number of Customers (d) | KWh of Sales Per Customer (e) | Revenue Per KWh Sold (f) |
|---|---|---|---|---|---|---|
| 1 | 11 General Service | 35,294 | 3,749,008 | 248 | 142,314.5161 | 0.1062 |
| 2 | 21 Large General Service | 119,008 | 14,149,713 | 68 | 1,750,117.6471 | 0.1189 |
| 3 | 25 Extra Large General Service | 2,154,938 | 130,411,938 | 27 | 79,812,518.5185 | 0.0605 |
| 4 | 30 Pumping Service | 31,159 | 3,440,241 | 50 | 623,180 | 0.1104 |
| 5 | 31 Pumping Service | 49,201 | 6,080,304 | 657 | 74,887.3668 | 0.1236 |
| 6 | 32 Residential and Farm Pumping Service | 4,438 | 522,625 | 109 | 40,715.5963 | 0.1178 |
| 7 | 47 Area Lighting Comm/Ind | 67 | 34,635 | 0 | | 0.5169 |
| 8 | 48 Residential and Farm Area Lighting | 1 | 327 | 0 | | 0.654 |
| 9 | 49 Area Lighting | 41 | 15,137 | 0 | | 0.3692 |
| 10 | 58 Tax Adjustment | 0 | 937,958 | 0 | | |
| 11 | 87 Solar Select | | 39,657 | | | |
| 12 | 95 Optional Renewable Power | 0 | 962 | 0 | | |
| 41 | TOTAL Billed Large (or Ind.) Sales | 2,394,147 | 159,382,505 | 1,159 | 2,065,700.604 | 0.0666 |
| 42 | TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6) | 1,322 | 89,526 | | | 0.0677 |
| 43 | TOTAL Large (or Ind.) | 2,395,469 | 159,472,031 | 1,159 | 2,066,841.2425 | 0.0666 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## SALES OF ELECTRICITY BY RATE SCHEDULES

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

| Line No. | Number and Title of Rate Schedule (a) | MWh Sold (b) | Revenue (c) | Average Number of Customers (d) | KWh of Sales Per Customer (e) | Revenue Per KWh Sold (f) |
|---|---|---|---|---|---|---|
| 1 | 42 Company Owned Steet Light Service | 12,667 | 8,775,653 | 660 | 19,192.4242 | 0.6928 |
| 2 | 44 Company Owned Steet Light Energy & Maintenance Service - High Pressure Sodium Vapor | 375 | 84,189 | 22 | 17,045.4545 | 0.2245 |
| 3 | 45 Company Owned Steet Light Energy Service | 341 | 37,614 | 13 | 26,230.7692 | 0.1103 |
| 4 | 46 Company Owned Steet Light Energy Service | 1,373 | 240,570 | 66 | 20,803.0303 | 0.1752 |
| 5 | 58 Tax Adjustment | 0 | 326,752 | 0 | | |
| 41 | TOTAL Billed Public Street and Highway Lighting | 14,756 | 9,464,778 | 761 | 19,390.276 | 0.6414 |
| 42 | TOTAL Unbilled Rev. (See Instr. 6) | | | | | |
| 43 | TOTAL | 14,756 | 9,464,778 | 761 | 19,390.276 | 0.6414 |

| Name of Respondent:<br>Avista Corporation | This report is:<br>(1) ☑ An Original<br>(2) ☐ A Resubmission | Date of Report:<br>04/17/2026 | Year/Period of Report<br>End of: 2025/ Q4 |
|---|---|---|---|

## SALES OF ELECTRICITY BY RATE SCHEDULES

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

| Line No. | Number and Title of Rate Schedule (a) | MWh Sold (b) | Revenue (c) | Average Number of Customers (d) | KWh of Sales Per Customer (e) | Revenue Per KWh Sold (f) |
|---|---|---|---|---|---|---|
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| 39 | | | | | | |
| 40 | | | | | | |
| 41 | TOTAL Billed Other Sales to Public Authorities | | | | | |
| 42 | TOTAL Unbilled Rev. (See Instr. 6) | | | | | |
| 43 | TOTAL | | | | | |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## SALES OF ELECTRICITY BY RATE SCHEDULES

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

| Line No. | Number and Title of Rate Schedule (a) | MWh Sold (b) | Revenue (c) | Average Number of Customers (d) | KWh of Sales Per Customer (e) | Revenue Per KWh Sold (f) |
|---|---|---|---|---|---|---|
| 1 | | | | | | |
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| 39 | | | | | | |
| 40 | | | | | | |
| 41 | TOTAL Billed Sales To Railroads and Railways | | | | | |
| 42 | TOTAL Unbilled Rev. (See Instr. 6) | | | | | |
| 43 | TOTAL | | | | | |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
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4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

| Line No. | Number and Title of Rate Schedule (a) | MWh Sold (b) | Revenue (c) | Average Number of Customers (d) | KWh of Sales Per Customer (e) | Revenue Per KWh Sold (f) |
|---|---|---|---|---|---|---|
| 1 | 01 Residential Service | 173 | 20,321 | 14 | 12,357.1429 | 0.1175 |
| 2 | 11 General Service | 5,135 | 657,684 | 123 | 41,747.9675 | 0.1281 |
| 3 | 12 Residential & Farm General Service | 15 | 2,449 | 1 | 15,000 | 0.1633 |
| 4 | 13 Optional Commercial Electric Vehicle Rate - General Service | 770 | 124,679 | 23 | 33,478.2609 | 0.1619 |
| 5 | 21 Large General Service | 10,132 | 1,253,877 | 15 | 675,466.6667 | 0.1238 |
| 6 | 31 Pumping Service | 713 | 82,761 | 5 | 142,600 | 0.1161 |
| 7 | 32 Residential and Farm Pumping Service | 28 | 3,351 | 1 | 28,000 | 0.1197 |
| 8 | 47 Area Light | 108 | 66,914 | 0 | | 0.6196 |
| 9 | 48 Residential and Farm Area Lighting | 1 | 494 | 0 | | 0.494 |
| 10 | 49 Area Lighting | 4 | 1,965 | 0 | | 0.4913 |
| 11 | 58 Tax Adjustment | 0 | 1,120 | 0 | | |
| 41 | TOTAL Billed Interdepartmental Sales | 17,079 | 2,215,615 | 182 | 93,840.6593 | 0.1297 |
| 42 | TOTAL Unbilled Rev. (See Instr. 6) | | | | | |
| 43 | TOTAL | 17,079 | 2,215,615 | 182 | 93,840.6593 | 0.1297 |

## SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
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4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

| Line No. | Number and Title of Rate Schedule (a) | MWh Sold (b) | Revenue (c) | Average Number of Customers (d) | KWh of Sales Per Customer (e) | Revenue Per KWh Sold (f) |
|---|---|---|---|---|---|---|
| 1 | Provision for Rate Refund | | 9,401,186 | | | |
| 41 | TOTAL Billed Provision For Rate Refunds | 0 | 9,401,186 | 0 | | |
| 42 | TOTAL Unbilled Rev. (See Instr. 6) | | | | | |
| 43 | TOTAL | | 9,401,186 | | | |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

| Line No. | Number and Title of Rate Schedule (a) | MWh Sold (b) | Revenue (c) | Average Number of Customers (d) | KWh of Sales Per Customer (e) | Revenue Per KWh Sold (f) |
|---|---|---|---|---|---|---|
| 41 | TOTAL Billed - All Accounts | 9,688,508 | 1,112,393,442 | 424,410 | 22,828.1803 | 0.1148 |
| 42 | TOTAL Unbilled Rev. (See Instr. 6) - All Accounts | 68,338 | 11,320,349 | | | 0.1657 |
| 43 | TOTAL - All Accounts | 9,756,846 | 1,123,713,791 | 424,410 | 22,989.1991 | 0.1152 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## SALES FOR RESALE (Account 447)

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

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

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

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

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

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

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

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the last line of the schedule. Report subtotals and total for columns (g) through (k).
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the last line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | ACTUAL DEMAND (MW) Average Monthly NCP Demand (e) | Average Monthly CP Demand (f) | Megawatt Hours Sold (g) | REVENUE Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | AlbertaEX, L.P. | SF | Tariff 9 | | | | 1,664 | | 68,480 | | 68,480 |
| 2 | Altop Energy Trading | SF | Tariff 9 | | | | 54,846 | | 2,250,748 | | 2,250,748 |
| 3 | Altop Energy Trading | IF [(b)] | Tariff 9 | | | | 95 | | (89,846) | | (89,846) |
| 4 | Avangrid Renewables, LLC | SF | Tariff 9 | | | | 73,283 | | 2,943,232 | | 2,943,232 |
| 5 | Avangrid Renewables, LLC | LF | Tariff 12 [(az)] | | | | 14 | | 478 | | 478 |
| 6 | Avangrid Renewables, LLC | LF [(c)] | Tariff 9 | | | | 80 | | (25,153) | | (25,153) |
| 7 | Avangrid Renewables, LLC | IF [(d)] | Tariff 9 | | | | 68,949 | | 0 | | 0 |
| 8 | BHE Power Watch, LLC | LF | Tariff 12 [(ba)] | | | | 12 | | 553 | | 553 |
| 9 | BP Energy Company | SF | Tariff 9 | | | | 287,592 | | 12,120,553 | | 12,120,553 |
| 10 | Basin Electric Power Cooperative | SF | Tariff 9 | | | | 400 | | 26,584 | | 26,584 |
| 11 | Bonneville Power Administration | SF | Tariff 9 | | | | 882,273 | | 35,411,715 | | 35,411,715 |
| 12 | Bonneville Power Administration | LF | Tariff 12 [(bb)] | | | | 27 | | 1,243 | | 1,243 |
| 13 | Bonneville Power Administration | LF [(e)] | Tariff 9 | | | | 64,596 | | 2,292,514 | | 2,292,514 |
| 14 | Bonneville Power Administration | LF [(f)] | Tariff 9 | | | | 131,052 | | 0 | | 0 |
| 15 | British Columbia Hydro and Power Authority | LF | Tariff 12 [(bc)] | | | | 16 | | 612 | | 612 |
| 16 | Brookfield Energy Marketing LP | SF | Tariff 9 | | | | 16,832 | | 661,122 | | 661,122 |
| 17 | CP Energy Marketing (US) Inc. | SF | Tariff 9 | | | | 370 | | 25,430 | | 25,430 |
| 18 | California Independent System Operator Corporation | SF | Tariff 9 | | | | 1,769 | | 10,231 | | 10,231 |
| 19 | Calpine Energy Services, LP | SF | Tariff 9 | | | | 14,180 | | 504,842 | | 504,842 |
| 20 | Chelan County PUD No. 1 | LF | Tariff 12 [(bd)] | | | | 4 | | 84 | | 84 |
| 21 | Chelan County PUD No. 1 | SF | Tariff 9 | | | | 8,400 | | 301,700 | | 301,700 |
| 22 | Citadel Energy Marketing LLC | SF | Tariff 9 | | | | 6,800 | | 285,240 | | 285,240 |
| 23 | Clatskanie Peoples PUD | SF | Tariff 9 | | | | 1,850 | | 51,876 | | 51,876 |
| 24 | ConocoPhillips Company | SF | Tariff 9 | | | | 43,355 | | 2,420,146 | | 2,420,146 |
| 25 | Constellation Energy Generation, LLC | SF | Tariff 9 | | | | 6,873 | | 273,645 | | 273,645 |
| 26 | Constellation Energy Generation, LLC | LF [(g)] | Tariff 9 | | | | 0 | | (386) | | (386) |
| 27 | Douglas County PUD No. 1 | IF [(h)] | Tariff 9 | | | | | | (24) | | (24) |
| 28 | DRW Energy Trading LLC | SF | Tariff 9 | | | | 128,394 | | 5,131,582 | | 5,131,582 |
| 29 | Dynasty Power, Inc. | SF | Tariff 9 | | | | 258,503 | | 9,942,912 | | 9,942,912 |
| 30 | Dynasty Power, Inc. | LF [(i)] | Tariff 9 | | | | 269 | | 5,934 | | 5,934 |
| 31 | EDF Trading North America, LLC | SF | Tariff 9 | | | | 3,109 | | 135,496 | | 135,496 |
| 32 | EDF Trading North America, LLC | LF [(j)] | Tariff 9 | | | | 11 | | 786 | | 786 |
| 33 | Energy Keepers, Inc. | SF | Tariff 9 | | | | 14,637 | | 590,767 | | 590,767 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 34 | Energy Keepers, Inc. | LF[k] | Tariff 9 | | | | 631 | | 26,189 | | 26,189 |
| 35 | Eugene Water Electric Board | SF | Tariff 9 | | | | 9,159 | | 326,185 | | 326,185 |
| 36 | Grant County PUD No. 2 | LF | Tariff 12[be] | | | | 3 | | 120 | | 120 |
| 37 | Grant County PUD No. 2 | SF | Tariff 9 | | | | 275,350 | | 19,458,763 | | 19,458,763 |
| 38 | Gridforce Energy Management, LLC | LF | Tariff 12[bf] | | | | 263 | | 11,700 | | 11,700 |
| 39 | Guzman Energy, LLC | SF | Tariff 9 | | | | 8,873 | | 404,161 | | 404,161 |
| 40 | Guzman Energy, LLC | LF[l] | Tariff 9 | | | | 136 | | 7,054 | | 7,054 |
| 41 | Idaho Power Company | SF | Tariff 9 | | | | 5,065 | | 213,771 | | 213,771 |
| 42 | Idaho Power Company | LF | Tariff 12[bg] | | | | 28 | | 1,082 | | 1,082 |
| 43 | Idaho Power Company Balancing | SF | Tariff 9 | | | | 4,008 | | 156,904 | | 156,904 |
| 44 | Idaho Power Company Balancing | LF[m] | Tariff 9 | | | | 7,432 | | 273,497 | | 273,497 |
| 45 | Idaho Power Company Balancing | LF[n] | Tariff 9 | | | | 666 | | 0 | | 0 |
| 46 | Idaho Power Company Balancing | LF[o] | Tariff 9 | | | | 60,295 | | 0 | | 0 |
| 47 | Idaho Power Company Balancing | LF[p] | Tariff 9 | | | | 152,767 | | 0 | | 0 |
| 48 | Kootenai Electric Cooperative | IF[q] | Tariff 9 | | | | 0 | | (1,053) | | (1,053) |
| 49 | Kootenai Renewable Energy LLC | IF[r] | Tariff 9 | | | | 698 | | 23,870 | | 23,870 |
| 50 | Macquarie Energy LLC | SF | Tariff 9 | | | | 52,494 | | 2,140,474 | | 2,140,474 |
| 51 | Macquarie Energy LLC | LF[s] | Tariff 9 | | | | 744 | | 26,484 | | 26,484 |
| 52 | MAG Energy Solutions | IF[t] | Tariff 9 | | | | 108 | | 2,223 | | 2,223 |
| 53 | Mercuria Energy America, LLC | LF[u] | Tariff 9 | | | | 72 | | (2,128) | | (2,128) |
| 54 | Merrill Lynch Commodities, Inc. | SF | Tariff 9 | | | | 36,800 | | 2,383,440 | | 2,383,440 |
| 55 | Mizuho Securities USA Inc. | OS[v] | NA | | | | 0 | | | 8,525,013 | 8,525,013 |
| 56 | Morgan Stanley Capital Group Inc. | SF | Tariff 9 | | | | 110,451 | | 4,301,564 | | 4,301,564 |
| 57 | Morgan Stanley Capital Group Inc. | LF[w] | Tariff 9 | | | | 5,327 | | 181,424 | | 181,424 |
| 58 | Morgan Stanley Capital Group Inc. | LF[x] | Tariff 9 | | | | 456,493 | | 19,392,711 | | 19,392,711 |
| 59 | Morgan Stanley Capital Group Inc. | SF | Tariff 9 | | | | 0 | 275,940[bo] | | | 275,940 |
| 60 | Morgan Stanley Capital Group Inc. | SF | Tariff 9 | | | | 0 | 275,940[bp] | | | 275,940 |
| 61 | Nevada Power Company | IF[y] | Tariff 9 | | | | | | (575) | | (575) |
| 62 | NorthWestern Energy | SF | Tariff 9 | | | | 23,511 | | 1,310,391 | | 1,310,391 |
| 63 | NorthWestern Energy | LF[z] | Tariff 9 | | | | 92 | | 138 | | 138 |
| 64 | NorthWestern Energy | LF | Tariff 12[bh] | | | | 2 | | 74 | | 74 |
| 65 | NorthWestern Energy | LF[aa] | Tariff 9 | | | | 7,231 | | 309,401 | | 309,401 |
| 66 | NorthWestern Energy | LF[ab] | Tariff 9 | | | | 108,866 | | 0 | | 0 |
| 67 | PacifiCorp | SF | Tariff 9 | | | | 105,870 | | 4,985,024 | | 4,985,024 |
| 68 | PacifiCorp | LF[ac] | Tariff 9 | | | | 68,662 | | 0 | | 0 |
| 69 | PacifiCorp | LF | Tariff 12[bi] | | | | 223 | | 9,234 | | 9,234 |
| 70 | PacifiCorp | LF[ad] | Tariff 9 | | | | 1,573 | | 7,557 | | 7,557 |
| 71 | PacifiCorp | LF[ae] | Tariff 9 | | | | 4,824 | | 206,267 | | 206,267 |
| 72 | Pend Oreille County Public Utility District #1 | LF | Tariff 9 | | | | 24 | 505,766[bq] | | | 505,766 |
| 73 | Pend Oreille County Public Utility District #1 | LF[af] | Tariff 9 | | | | 10,309 | | 376,997 | | 376,997 |
| 74 | Pend Oreille County Public Utility District #1 | LF[ag] | Tariff 9 | | | | 93 | | 4,544 | | 4,544 |
| 75 | Pend Oreille County Public Utility District #1 | SF | Tariff 9 | | | | 2,036 | | 115,202 | | 115,202 |
| 76 | Phillips 66 Energy Trading, LLC | SF | Tariff 9 | | | | 156,211 | | 5,578,986 | | 5,578,986 |
| 77 | Phillips 66 Energy Trading, LLC | IF[ah] | Tariff 9 | | | | 11,021 | | 417,008 | | 417,008 |
| 78 | Portland General Electric | SF | Tariff 9 | | | | 5,430 | | 273,275 | | 273,275 |
| 79 | Portland General Electric | LF | Tariff 12[bj] | | | | 45 | | 2,181 | | 2,181 |
| 80 | Portland General Electric | LF[ai] | Tariff 9 | | | | 195 | | 6,219 | | 6,219 |
| 81 | Portland General Electric | IF[aj] | Tariff 9 | | | | 9,644 | | 412,535 | | 412,535 |
| 82 | Power Ex | SF | Tariff 9 | | | | 156,152 | | 4,875,542 | | 4,875,542 |
| 83 | Power Ex | LF[ak] | Tariff 9 | | | | 5,565 | | 171,999 | | 171,999 |
| 84 | Puget Sound Energy | LF[al] | Tariff 9 | | | | 12,055 | | 515,668 | | 515,668 |
| 85 | Puget Sound Energy | SF | Tariff 9 | | | | 17,060 | | 778,825 | | 778,825 |
| 86 | Puget Sound Energy | LF | Tariff 12[bk] | | | | 10 | | 384 | | 384 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 87 | Puget Sound Energy | [am] LF | Tariff 9 | | | | 343 | | 4,333 | | 4,333 |
| 88 | Rainbow Energy Marketing | SF | Tariff 9 | | | | 26,260 | | 963,209 | | 963,209 |
| 89 | Rainbow Energy Marketing | [an] LF | Tariff 9 | | | | 11 | | 3,056 | | 3,056 |
| 90 | Sacramento Municipal Utility District | LF | [bl] Tariff 12 | | | | 5 | | 286 | | 286 |
| 91 | Seattle City Light | SF | Tariff 9 | | | | 7,260 | | 297,558 | | 297,558 |
| 92 | Seattle City Light | [ao] LF | Tariff 9 | | | | 661 | | 25,928 | | 25,928 |
| 93 | Seattle City Light | [ap] LF | Tariff 9 | | | | 3 | | 17 | | 17 |
| 94 | Seattle City Light | LF | [bm] Tariff 12 | | | | 17 | | 493 | | 493 |
| 95 | Shell Energy N.A. | SF | Tariff 9 | | | | 162,716 | | 5,480,556 | | 5,480,556 |
| 96 | Shell Energy N.A. | [aq] LF | Tariff 9 | | | | 37 | | 880 | | 880 |
| 97 | Shell Energy N.A. | LF | Tariff 9 | | | | 0 | [br] 1,400 | | | 1,400 |
| 98 | Snohomish County PUD | SF | Tariff 9 | | | | 32,605 | | 3,056,825 | | 3,056,825 |
| 99 | Tacoma Power | SF | Tariff 9 | | | | 2,275 | | 80,115 | | 80,115 |
| 100 | Tacoma Power | [ar] LF | Tariff 9 | | | | 1,580 | | 64,636 | | 64,636 |
| 101 | Tacoma Power | LF | [bn] Tariff 12 | | | | 2 | | 38 | | 38 |
| 102 | Talen Energy Montana, LLC | [as] LF | Tariff 9 | | | | 7,231 | | 309,401 | | 309,401 |
| 103 | The Energy Authority | SF | Tariff 9 | | | | 185,371 | | 7,227,163 | | 7,227,163 |
| 104 | The Energy Authority | [at] LF | Tariff 9 | | | | 220 | | 5,815 | | 5,815 |
| 105 | TransAlta Energy Marketing | SF | Tariff 9 | | | | 147,408 | | 5,095,642 | | 5,095,642 |
| 106 | TransAlta Energy Marketing | [au] LF | Tariff 9 | | | | 78 | | 2,887 | | 2,887 |
| 107 | Vitol, Inc. | SF | Tariff 9 | | | | 15,170 | | 579,337 | | 579,337 |
| 108 | Wells Fargo Securities, LLC | [av] OS | NA | | | | 0 | | | 3,657,965 | 3,657,965 |
| 109 | IntraCompany Wheeling | [aw] LF | | | | | | | (52,728,402) | 52,728,402 | 0 |
| 110 | IntraCompany Generation | [ax] LF | | | | | | | | 1,252,545 | 1,252,545 |
| 111 | California Independent System Operator Corporation | [ay] OS | Tariff 9 | | | | | | | 8,745,261 | 8,745,261 |
| 112 | [a] Powerdex Pricing Accrual | SF | Tariff 9 | | | | | | 8,200 | | 8,200 |
| 15 | Subtotal - RQ | | | | | | | | | | 0 |
| 16 | Subtotal-Non-RQ | | | | | | 4,554,075 | 1,059,046 | 115,506,380 | 74,909,186 | 191,474,612 |
| 17 | Total | | | | | | 4,554,075 | 1,059,046 | 115,506,380 | 74,909,186 | 191,474,612 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

FOOTNOTE DATA

| |
|---|
| (a) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale |
| To accrue for missing Powerdex Prices at year end 2025 |
| (b) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses 05/01/2025-12/31/2027 |
| (c) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 01/01/2016-12/31/2027 |
| (d) Concept: StatisticalClassificationCode |
| 06/06/2023-12/31/2027 ETSR is an export resource associated with EIM |
| (e) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 03/02/2022-12/31/2027 |
| (f) Concept: StatisticalClassificationCode |
| 03/02/2022-12/31/2027 ETSR is an export resource associated with EIM |
| (g) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 05/01/2022-12/31/2027 |
| (h) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses |
| (i) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 06/01/2021-12/31/2027 |
| (j) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 02/01/2022-12/31/2027 |
| (k) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 01/01/2016-12/31/2027 |
| (l) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 05/01/2021-12/31/2027 |
| (m) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 01/01/2016-12/31/2027 |
| (n) Concept: StatisticalClassificationCode |
| 03/02/2022-12/31/2027 ETSR is an export resource associated with EIM |
| (o) Concept: StatisticalClassificationCode |
| 03/02/2022-12/31/2027 ETSR is an export resource associated with EIM |
| (p) Concept: StatisticalClassificationCode |
| 03/02/2022-12/31/2027 ETSR is an export resource associated with EIM |
| (q) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 02/01/2022-03/31/2024 |
| (r) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 04/01/2024-12/31/2026 |
| (s) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 07/18/2018-12/31/2027 |
| (t) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 01/16/2024-12/31/2026 |
| (u) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 06/01/2021-12/31/2027 |
| (v) Concept: StatisticalClassificationCode |
| Financial SWAP |
| (w) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 01/01/2016-12/31/2027 |
| (x) Concept: StatisticalClassificationCode |
| Resource Contingent Bundled REC - Energy and Green Attributes 03/01/2019 - 12/31/2026 |
| (y) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses |
| (z) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 01/01/2016-12/31/2027 |
| (aa) Concept: StatisticalClassificationCode |
| Northwestern Energy LLC sale expires December 31, 2025 |
| (ab) Concept: StatisticalClassificationCode |
| 01/26/2022-12/31/2027 ETSR is an export resource associated with EIM |
| (ac) Concept: StatisticalClassificationCode |
| 01/27/2022-12/31/2027 ETSR is an export resource associated with EIM |
| (ad) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 02/01/2022-12/31/2027 |

| |
|---|
| (ae) Concept: StatisticalClassificationCode |
| PacifiCorp sale expires December 31, 202 |
| (af) Concept: StatisticalClassificationCode |
| Deviation Energy |
| (ag) Concept: StatisticalClassificationCode |
| Deviation Energy |
| (ah) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 08/01/2023-12/31/2027 |
| (ai) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 02/01/2022-12/31/2027 |
| (aj) Concept: StatisticalClassificationCode |
| Portland General Electric sale expires December 31,2025 |
| (ak) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 05/01/2019-12/31/2027 |
| (al) Concept: StatisticalClassificationCode |
| Puget Sound Energy sale expires December 31, 2025 |
| (am) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 02/01/2022-12/31/2027 |
| (an) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 01/01/2016-12/31/2027 |
| (ao) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 03/19/2008-10/31/2026 |
| (ap) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 02/01/2022-12/31/2027 |
| (aq) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 02/01/2022-12/31/2027 |
| (ar) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 03/19/2008-10/31/2026 |
| (as) Concept: StatisticalClassificationCode |
| Talen Energy Montana, LLC sale expires December 31, 2025 |
| (at) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 01/01/2016-12/31/2027 |
| (au) Concept: StatisticalClassificationCode |
| Financially Settled Transmission Losses effective 01/01/2016-12/31/2027 |
| (av) Concept: StatisticalClassificationCode |
| Financial SWAP |
| (aw) Concept: StatisticalClassificationCode |
| Intra Company Wheeling |
| (ax) Concept: StatisticalClassificationCode |
| Intra Company Generation - Sale of Ancillary Services |
| (ay) Concept: StatisticalClassificationCode |
| Energy Imbalance Market (EIM) Sales |
| (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 |
| Capacity |
| (bp) Concept: DemandChargesRevenueSalesForResale |
| Capacity |
| (bq) Concept: DemandChargesRevenueSalesForResale |
| Contract expires September 30, 2026 |
| (br) Concept: DemandChargesRevenueSalesForResale |
| Spinning Reserves |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

**ELECTRIC OPERATION AND MAINTENANCE EXPENSES**

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

| Line No. | Account (a) | Amount for Current Year (b) | Amount for Previous Year (c) |
|---|---|---|---|
| 1 | 1. POWER PRODUCTION EXPENSES | | |
| 2 | A. Steam Power Generation | | |
| 3 | Operation | | |
| 4 | (500) Operation Supervision and Engineering | 278,622 | 211,674 |
| 5 | (501) Fuel | 42,738,354 | 41,962,181 |
| 6 | (502) Steam Expenses | 4,208,474 | 3,939,808 |
| 7 | (503) Steam from Other Sources | (106) | 27,702 |
| 8 | (Less) (504) Steam Transferred-Cr. | | 0 |
| 9 | (505) Electric Expenses | 944,045 | 785,795 |
| 10 | (506) Miscellaneous Steam Power Expenses | 6,692,432 | 6,252,999 |
| 11 | (507) Rents | 0 | 0 |
| 12 | (509) Allowances | 0 | 2,035,905 |
| 13 | TOTAL Operation (Enter Total of Lines 4 thru 12) | 54,861,821 | 55,216,064 |
| 14 | Maintenance | | |
| 15 | (510) Maintenance Supervision and Engineering | 517,895 | 515,870 |
| 16 | (511) Maintenance of Structures | 1,128,907 | 1,022,336 |
| 17 | (512) Maintenance of Boiler Plant | 9,332,329 | 9,714,776 |
| 18 | (513) Maintenance of Electric Plant | 2,903,800 | 2,973,167 |
| 18.1 | (513.1) Maintenance of Computer Hardware | 0 | 0 |
| 18.2 | (513.2) Maintenance of Computer Software | 0 | 0 |
| 18.3 | (513.3) Maintenance of Communication Equipment | 0 | 0 |
| 19 | (514) Maintenance of Miscellaneous Steam Plant | 1,854,876 | 1,959,793 |
| 20 | TOTAL Maintenance (Enter Total of Lines 15 thru 19) | 15,737,807 | 16,185,942 |
| 21 | TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20) | 70,599,628 | 71,402,006 |
| 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 |
| 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 |
| 38.1 | (531.1) Maintenance of Computer Hardware | 0 | 0 |
| 38.2 | (531.2) Maintenance of Computer Software | 0 | 0 |
| 38.3 | (531.3) Maintenance of Communication Equipment | 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 | 3,079,006 | 2,763,467 |
| 45 | (536) Water for Power | 1,284,827 | 1,174,129 |
| 46 | (537) Hydraulic Expenses | 11,224,064 | 10,193,403 |
| 47 | (538) Electric Expenses | 7,283,612 | 6,783,801 |
| 48 | (539) Miscellaneous Hydraulic Power Generation Expenses | 1,343,254 | 1,345,977 |
| 49 | (540) Rents | 8,066,828 | 7,756,327 |
| 50 | TOTAL Operation (Enter Total of Lines 44 thru 49) | 32,281,591 | 30,017,104 |

| | | | |
|---|---|---|---|
| 51 | C. Hydraulic Power Generation (Continued) | | |
| 52 | Maintenance | | |
| 53 | (541) Maintenance Supervision and Engineering | 599,102 | 445,155 |
| 54 | (542) Maintenance of Structures | 785,396 | 318,781 |
| 55 | (543) Maintenance of Reservoirs, Dams, and Waterways | 676,853 | 252,728 |
| 56 | (544) Maintenance of Electric Plant | 3,276,876 | 2,858,446 |
| 56.1 | (544.1) Maintenance of Computer Hardware | 0 | 0 |
| 56.2 | (544.2) Maintenance of Computer Software | 0 | 0 |
| 56.3 | (544.3) Maintenance of Communication Equipment | 0 | 0 |
| 57 | (545) Maintenance of Miscellaneous Hydraulic Plant | 856,832 | 650,044 |
| 58 | TOTAL Maintenance (Enter Total of lines 53 thru 57) | 6,195,059 | 4,525,154 |
| 59 | TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58) | 38,476,650 | 34,542,258 |
| 60 | D. Other Power Generation | | |
| 61 | Operation | | |
| 62 | (546) Operation Supervision and Engineering | 545,013 | 529,903 |
| 63 | (547) Fuel | 110,183,092 | 111,227,168 |
| 64 | (548) Generation Expenses | 5,379,487 | 5,165,896 |
| 65 | (549) Miscellaneous Other Power Generation Expenses | 1,461,887 | 1,421,816 |
| 66 | (550) Rents | 103,105 | 76,438 |
| 67 | TOTAL Operation (Enter Total of Lines 62 thru 67) | 117,672,584 | 118,421,221 |
| 68 | Maintenance | | |
| 69 | (551) Maintenance Supervision and Engineering | 656,671 | 756,654 |
| 70 | (552) Maintenance of Structures | 103,025 | 131,043 |
| 71 | (553) Maintenance of Generating and Electric Plant | 4,058,115 | 2,807,857 |
| 71.1 | (553.1) Maintenance of Computer Hardware | 0 | 0 |
| 71.2 | (553.2) Maintenance of Computer Software | 0 | 0 |
| 71.3 | (553.3) Maintenance of Communication Equipment | 0 | 0 |
| 72 | (554) Maintenance of Miscellaneous Other Power Generation Plant | 329,134 | 889,234 |
| 73 | TOTAL Maintenance (Enter Total of Lines 69 thru 72) | 5,146,945 | 4,584,788 |
| 74 | TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73) | 122,819,529 | 123,006,009 |
| 75 | E. Other Power Supply Expenses | | |
| 76 | (555) Purchased Power | 238,995,634 | 249,851,190 |
| 76.1 | (555.1) Power Purchased for Storage Operations | 0 | 0 |
| 76.2 | (555.2) Bundled Environmental Credits | 0 | 0 |
| 76.3 | (555.3) Unbundled Environmental Credits | 209,300 | 0 |
| 77 | (556) System Control and Load Dispatching | 1,055,853 | 961,071 |
| 78 | (557) Other Expenses | (29,259,217) | 57,758,008 |
| 79 | TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78) | 211,001,570 | 308,570,269 |
| 79.1 | F. Solar Generation | | |
| 79.2 | Operation | | |
| 79.3 | (558.1) Operation Supervision and Engineering | | |
| 79.4 | (558.2) Solar Panel Generation and Other Plant Operating Expenses | | |
| 79.6 | (558.4) Rents | | |
| 79.7 | TOTAL Operation (Enter Total of lines 79.3 thru 79.6) | 0 | 0 |
| 79.8 | Maintenance | | |
| 79.9 | (558.6) Maintenance Supervision and Engineering | | |
| 79.10 | (558.7) Maintenance of Solar Panels, Structures, and Equipment | | |
| 79.11 | (558.8) Maintenance of Computer Hardware | | |
| 79.12 | (558.9) Maintenance of Computer Software | | |
| 79.13 | (558.10) Maintenance of Communication Equipment | | |
| 79.14 | (558.11) Maintenance of Miscellaneous Solar Generation Plant | | |
| 79.15 | TOTAL Maintenance (Enter Total of lines 79.9 thru 79.14) | 0 | 0 |
| 79.16 | TOTAL Power Production Expenses-Solar (total of lines 79.7 & 79.15) | 0 | 0 |
| 79.17 | G. Wind Generation | | |
| 79.18 | Operation | | |
| 79.19 | (558.13) Operation Supervision and Engineering | | |
| 79.20 | (558.14) Wind Turbine Generation and Other Plant Operating Expenses | | |
| 79.21 | (558.16) Rents | | |
| 79.22 | TOTAL Operation (Enter Total of lines 79.19 thru 79.21) | 0 | 0 |
| 79.23 | Maintenance | | |
| 79.24 | (558.18) Maintenance Supervision and Engineering | | |
| 79.25 | (558.19) Maintenance of Wind Turbines, Structures, and Equipment | | |
| 79.26 | (558.20) Maintenance of Computer Hardware | | |

| | | | |
|---|---|---|---|
| 79.27 | (558.21) Maintenance of Computer Software | | |
| 79.28 | (558.22) Maintenance of Communication Equipment | | |
| 79.29 | (558.23) Maintenance of Miscellaneous Wind Generation Plant | | |
| 79.30 | TOTAL Maintenance (Enter Total of lines 79.24 thru 79.29) | 0 | 0 |
| 79.31 | TOTAL Power Production Expenses-Wind (total of lines 79.22 & 79.30) | 0 | 0 |
| 79.32 | H. Other Renewable Generation | | |
| 79.33 | Operation | | |
| 79.34 | (559.1) Operation Supervision and Engineering | | |
| 79.35 | (559.2) Other Miscellaneous Generation and Other Plant Operating Expenses | | |
| 79.36 | (559.3) Fuel | | |
| 79.37 | (559.4) Rents | | |
| 79.38 | TOTAL Operation (Enter Total of lines 79.34 thru 79.37) | 0 | 0 |
| 79.39 | Maintenance | | |
| 79.40 | (559.6) Maintenance Supervision and Engineering | | |
| 79.41 | (559.7) Maintenance of Structures | | |
| 79.42 | (559.9) Maintenance of Boilers | | |
| 79.43 | (559.10) Maintenance of Generating and Electric Equipment | | |
| 79.44 | (559.12) Maintenance of Computer Hardware | | |
| 79.45 | (559.13) Maintenance of Computer Software | | |
| 79.46 | (559.14) Maintenance of Communication Equipment | | |
| 79.47 | (559.15) Maintenance of Miscellaneous Renewable Production Plant | | |
| 79.48 | TOTAL Maintenance (Enter Total of lines 79.40 thru 79.47) | 0 | 0 |
| 79.49 | TOTAL Power Production Expenses-Other Renewable (total of lines 79.38 & 79.48) | 0 | 0 |
| 80 | TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74, 79, 79.16, 79.31, & 79.49) | 442,897,377 | 537,520,542 |
| 81 | 2. TRANSMISSION EXPENSES | | |
| 82 | Operation | | |
| 83 | (560) Operation Supervision and Engineering | 2,916,263 | 2,363,205 |
| 85 | (561.1) Load Dispatch-Reliability | 59,288 | 32,427 |
| 86 | (561.2) Load Dispatch-Monitor and Operate Transmission System | 1,542,138 | 1,377,075 |
| 87 | (561.3) Load Dispatch-Transmission Service and Scheduling | 1,212,301 | 971,187 |
| 88 | (561.4) Scheduling, System Control and Dispatch Services | 0 | 0 |
| 89 | (561.5) Reliability, Planning and Standards Development | 577,411 | 554,980 |
| 90 | (561.6) Transmission Service Studies | 0 | 0 |
| 91 | (561.7) Generation Interconnection Studies | 0 | 0 |
| 92 | (561.8) Reliability, Planning and Standards Development Services | 0 | 0 |
| 93 | (562) Station Expenses | 454,369 | 360,820 |
| 94 | (563) Overhead Lines Expenses | 574,311 | 550,123 |
| 95 | (564) Underground Lines Expenses | 0 | 0 |
| 96 | (565) Transmission of Electricity by Others | 30,244,061 | 22,557,221 |
| 97 | (566) Miscellaneous Transmission Expenses | 4,523,961 | 4,279,905 |
| 98 | (567) Rents | 91,900 | 88,928 |
| 99 | TOTAL Operation (Enter Total of Lines 83 thru 98) | 42,196,003 | 33,135,871 |
| 100 | Maintenance | | |
| 101 | (568) Maintenance Supervision and Engineering | 568,528 | 403,566 |
| 102 | (569) Maintenance of Structures | 836,580 | 455,239 |
| 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 | 917,185 | 595,153 |
| 108 | (571) Maintenance of Overhead Lines | 5,818,264 | 1,924,515 |
| 109 | (572) Maintenance of Underground Lines | 3,323 | 7,133 |
| 110 | (573) Maintenance of Miscellaneous Transmission Plant | 105,850 | 122,348 |
| 111 | TOTAL Maintenance (Total of Lines 101 thru 110) | 8,249,730 | 3,507,954 |
| 112 | TOTAL Transmission Expenses (Total of Lines 99 and 111) | 50,445,733 | 36,643,825 |
| 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 |

| | | | |
|---|---|---|---|
| 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 |
| 131.1 | 4. ENERGY STORAGE EXPENSES | | |
| 131.2 | Operation | | |
| 131.3 | (577.1) Operation Supervision and Engineering | | |
| 131.4 | (577.2) Operation of Energy Storage Equipment | | |
| 131.5 | (577.3) Storage Fuel | | |
| 131.6 | (577.4) Rents | | |
| 131.7 | Total Operation (Lines 131.3 thru 131.6) | 0 | 0 |
| 131.8 | Maintenance | | |
| 131.9 | (578.1) Maintenance Supervision and Engineering | | |
| 131.10 | (578.2) Maintenance of Energy Storage Equipment and Structures | | |
| 131.11 | (578.3) Maintenance of Computer Hardware | | |
| 131.12 | (578.4) Maintenance of Computer Software | | |
| 131.13 | (578.5) Maintenance of Communication Equipment | | |
| 131.14 | (578.6) Maintenance of Miscellaneous Other Energy Storage Plant | | |
| 131.15 | Total Maintenance (Lines 131.9 thru 131.14) | 0 | 0 |
| 131.16 | TOTAL Energy Storage Expenses (Total of 131.7 and 131.15) | 0 | 0 |
| 132 | 5. DISTRIBUTION EXPENSES | | |
| 133 | Operation | | |
| 134 | (580) Operation Supervision and Engineering | 3,902,186 | 3,768,183 |
| 135 | (581) Load Dispatching | 0 | 0 |
| 136 | (582) Station Expenses | 1,492,177 | 1,000,594 |
| 137 | (583) Overhead Line Expenses | 2,589,430 | 2,779,384 |
| 138 | (584) Underground Line Expenses | 2,706,498 | 2,583,804 |
| 139 | (585) Street Lighting and Signal System Expenses | 10,024 | 16,533 |
| 140 | (586) Meter Expenses | 2,173,107 | 2,179,506 |
| 141 | (587) Customer Installations Expenses | 926,332 | 816,250 |
| 142 | (588) Miscellaneous Expenses | 9,242,325 | 9,328,670 |
| 143 | (589) Rents | 257,792 | 252,435 |
| 144 | TOTAL Operation (Enter Total of Lines 134 thru 143) | 23,299,871 | 22,725,359 |
| 145 | Maintenance | | |
| 146 | (590) Maintenance Supervision and Engineering | 2,786,573 | 1,444,330 |
| 147 | (591) Maintenance of Structures | 495,658 | 331,882 |
| 148 | (592) Maintenance of Station Equipment | 542,026 | 704,181 |
| 148.1 | (592.2) Maintenance of Computer Hardware | 0 | 0 |
| 148.2 | (592.3) Maintenance of Computer Software | 0 | 0 |
| 148.3 | (592.4) Maintenance of Communication Equipment | 0 | 0 |
| 149 | (593) Maintenance of Overhead Lines | 31,318,449 | 24,355,102 |
| 150 | (594) Maintenance of Underground Lines | 849,429 | 813,168 |
| 151 | (595) Maintenance of Line Transformers | 336,722 | 335,588 |
| 152 | (596) Maintenance of Street Lighting and Signal Systems | 68,726 | 52,732 |
| 153 | (597) Maintenance of Meters | 40,668 | 47,211 |
| 154 | (598) Maintenance of Miscellaneous Distribution Plant | 631,127 | 954,667 |
| 155 | TOTAL Maintenance (Total of Lines 146 thru 154) | 37,069,378 | 29,038,861 |
| 156 | TOTAL Distribution Expenses (Total of Lines 144 and 155) | 60,369,249 | 51,764,220 |
| 157 | 6. CUSTOMER ACCOUNTS EXPENSES | | |
| 158 | Operation | | |
| 159 | (901) Supervision | 200,772 | 143,348 |
| 160 | (902) Meter Reading Expenses | 637,038 | 626,676 |
| 161 | (903) Customer Records and Collection Expenses | 9,345,288 | 9,048,196 |
| 162 | (904) Uncollectible Accounts | 4,811,953 | 5,768,159 |
| 163 | (905) Miscellaneous Customer Accounts Expenses | 171,050 | 185,602 |
| 164 | TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163) | 15,166,101 | 15,771,981 |

| | | | |
|---|---|---|---|
| 165 | 7. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES | | |
| 166 | Operation | | |
| 167 | (907) Supervision | 0 | |
| 168 | (908) Customer Assistance Expenses | 70,366,933 | 44,289,899 |
| 169 | (909) Informational and Instructional Expenses | 925,412 | 910,185 |
| 170 | (910) Miscellaneous Customer Service and Informational Expenses | 55,596 | 62,711 |
| 171 | TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170) | 71,347,941 | 45,262,795 |
| 172 | 8. SALES EXPENSES | | |
| 173 | Operation | | |
| 174 | (911) Supervision | 0 | 0 |
| 175 | (912) Demonstrating and Selling Expenses | 0 | 0 |
| 176 | (913) Advertising Expenses | 0 | 0 |
| 177 | (916) Miscellaneous Sales Expenses | 0 | 0 |
| 178 | TOTAL Sales Expenses (Enter Total of Lines 174 thru 177) | 0 | 0 |
| 179 | 9. ADMINISTRATIVE AND GENERAL EXPENSES | | |
| 180 | Operation | | |
| 181 | (920) Administrative and General Salaries | 40,844,696 | 32,528,109 |
| 182 | (921) Office Supplies and Expenses | 4,254,583 | 3,924,506 |
| 183 | (Less) (922) Administrative Expenses Transferred-Credit | 184,261 | 114,045 |
| 184 | (923) Outside Services Employed | 14,684,082 | 16,406,375 |
| 185 | (924) Property Insurance | 3,083,658 | 3,128,985 |
| 186 | (925) Injuries and Damages | 25,160,794 | 21,673,946 |
| 187 | (926) Employee Pensions and Benefits | 35,198,273 | 31,491,165 |
| 188 | (927) Franchise Requirements | 1,169 | 1,231 |
| 189 | (928) Regulatory Commission Expenses | 9,635,883 | 8,737,417 |
| 190 | (929) (Less) Duplicate Charges-Cr. | 0 | 0 |
| 191 | (930.1) General Advertising Expenses | 58 | 0 |
| 192 | (930.2) Miscellaneous General Expenses | 5,349,796 | 5,706,421 |
| 193 | (931) Rents | 1,038,088 | 1,021,020 |
| 194 | TOTAL Operation (Enter Total of Lines 181 thru 193) | 139,066,819 | 124,505,130 |
| 195 | Maintenance | | |
| 196 | (935) Maintenance of General Plant | 16,049,446 | 14,048,526 |
| 196.1 | (935.1) Maintenance of Computer Hardware | 400,358 | 0 |
| 196.2 | (935.2) Maintenance of Computer Software | 629,388 | 0 |
| 196.3 | (935.3) Maintenance of Communication Equipment | 84,684 | 0 |
| 196.4 | TOTAL Maintenance (Enter Total of lines 196 thru 196.3) | 17,163,876 | 14,048,526 |
| 197 | TOTAL Administrative & General Expenses (Total of Lines 194 and 196.4) | 156,230,695 | 138,553,656 |
| 198 | TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 131.16, 156, 164, 171, 178, and 197) | 796,457,096 | 825,517,019 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## PURCHASED POWER (Account 555)

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

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | Ferc Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW): Average Monthly NCP Demand (e) | Actual Demand (MW): Average Monthly CP Demand (f) | MegaWatt Hours Purchased (Excluding for Energy Storage) (g) | MegaWatt Hours Purchased for Energy Storage (h) | POWER EXCHANGES: MegaWatt Hours Received (i) | POWER EXCHANGES: MegaWatt Hours Delivered (j) | 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 | Adams Nielson Solar, LLC | LU | PURPA | | | | 43,647 | | | | | 1,912,175 | | 1,912,175 |
| 2 | AlbertaEX,L.P. | SF | Tariff 9 | | | | 1,128 | | | | | 34,840 | | 34,840 |
| 3 | Altop Energy Trading | SF | Tariff 9 | | | | 13,081 | | | | | 583,112 | | 583,112 |
| 4 | Avangrid Renewables, LLC | SF | Tariff 9 | | | | 23,305 | | | | | 705,268 | | 705,268 |
| 5 | [a] Avangrid Renewables, LLC | LF | NWPP | | | | 5 | | | | | 176 | | 176 |
| 6 | [b] Avangrid Renewables, LLC | IF | Tariff 9 | | | | 60,334 | | | | | | | 0 |
| 7 | BP Energy | SF | Tariff 9 | | | | 5,600 | | | | | 270,048 | | 270,048 |
| 8 | [c] Bonneville Power Administration | OS | BPA OATT | | | | | | | | | | 64,746 | 64,746 |
| 9 | [d] Bonneville Power Administration | LF | Tariff 8 | | | | 337 | | | | | | | 0 |
| 10 | Bonneville Power Administration | SF | Tariff 9 | | | | 107,152 | | | | | 3,678,689 | | 3,678,689 |
| 11 | [e] Bonneville Power Administration | LF | NWPP | | | | 100 | | | | | 3,935 | | 3,935 |
| 12 | [f] Bonneville Power Administration | OS | BPA OATT | | | | | | | | | | 97,922 | 97,922 |
| 13 | [g] Bonneville Power Administration | IF | Tariff 9 | | | | 89,327 | | | | | 3,497,270 | | 3,497,270 |
| 14 | [h] Bonneville Power Administration | LF | Tariff 9 | | | | 27,730 | | | | | | | 0 |
| 15 | Brookfield Energy Marketing LP | SF | Tariff 9 | | | | 6,400 | | | | | 209,150 | | 209,150 |
| 16 | CP Energy Marketing (US) Inc. | SF | Tariff 9 | | | | 3,235 | | | | | 119,697 | | 119,697 |
| 17 | California Independent System Operator | SF | Tariff 9 | | | | 8,546 | | | | | (48,885) | | (48,885) |
| 18 | Calpine Energy Services, LP | SF | Tariff 9 | | | | 4,870 | | | | | 31,170 | | 31,170 |
| 19 | Chelan County PUD | IU | Rocky Reach | | | | 51,029 | | | | | | | 0 |
| 20 | [i] Chelan County PUD | IU | Rocky Reach | | | | (23,804) | | | | | | | 0 |
| 21 | Chelan County PUD | SF | Tariff 9 | | | | 6,280 | | | | | 231,820 | | 231,820 |
| 22 | [j] Chelan County PUD | LF | NWPP | | | | 1 | | | | | 56 | | 56 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 23 | Chelan County PUD | IU | Chelan Sys | | | | 744,078 | | | | 38,216,758 | | | 38,216,758 |
| 24 | [k] Chelan County PUD | EX | Rocky Reach | | | | | | | | | | 733,245 | 733,245 |
| 25 | City of Spokane | IU | PURPA | | | | 43,799 | | | | | 2,267,593 | | 2,267,593 |
| 26 | City of Spokane | IU | PURPA | | | | 134,533 | | | | | 6,625,416 | | 6,625,416 |
| 27 | Clark Fork Hydro | LU | PURPA | | | | 734 | | | | | 50,783 | | 50,783 |
| 28 | Clatskanie PUD | SF | Tariff 9 | | | | 212 | | | | | 7,821 | | 7,821 |
| 29 | Clearwater Paper Company | IU | PURPA | | | | 483,235 | | | | | 17,478,610 | | 17,478,610 |
| 30 | Clearwater Wind III Project | LU | PURPA | | | | 376,674 | | | | | 11,302,031 | | 11,302,031 |
| 31 | Community Solar | LU | PURPA | | | | 500 | | | | | | | 0 |
| 32 | ConocoPhillips Company | SF | Tariff 9 | | | | 8,325 | | | | | 354,067 | | 354,067 |
| 33 | Constellation Energy Generation, LLC | SF | Tariff 9 | | | | 4,681 | | | | | 144,845 | | 144,845 |
| 34 | Deep Creek Energy, LLC | IU | PURPA | | | | 183 | | | | | 14,470 | | 14,470 |
| 35 | Douglas County PUD No. 1 | LU | Wells | | | | 48,540 | | | | 1,786,181 | | | 1,786,181 |
| 36 | [l] Douglas County PUD No. 1 | OS | Tariff 9 | | | | | | | | | | 255 | 255 |
| 37 | DRW Energy Trading | SF | Tariff 9 | | | | 16,000 | | | | | 1,037,004 | | 1,037,004 |
| 38 | Dynasty Power, Inc. | SF | Tariff 9 | | | | 167,774 | | | | | 7,196,014 | | 7,196,014 |
| 39 | East, South, Quincy Columbia Basin Irrigation Districts | LU | PURPA | | | | 418,012 | | | | | 18,149,272 | | 18,149,272 |
| 40 | EDF Trading No America | SF | Tariff 9 | | | | 1,305 | | | | | 48,130 | | 48,130 |
| 41 | Enel X North America, Inc. | LU | PURPA | | | | 1 | | | | | | | 0 |
| 42 | Energy Keepers, Inc. | SF | Tariff 9 | | | | 33,511 | | | | | 1,352,075 | | 1,352,075 |
| 43 | Eugene Water & Electric Board | SF | Tariff 9 | | | | 621 | | | | | 20,169 | | 20,169 |
| 44 | Ford Hydro Limited Partnership | LU | PURPA | | | | 2,766 | | | | | 137,337 | | 137,337 |
| 45 | Grant County PUD No. 2 | LU | Priest Rapids | | | | 292,691 | | | | 33,822,003 | | | 33,822,003 |
| 46 | [m] Grant County PUD No. 2 | LF | NWPP | | | | 7 | | | | | 271 | | 271 |
| 47 | [n] Grant County PUD No. 2 | EX | FERC #104 | | | | | | | | | | (7,821) | (7,821) |
| 48 | [o] Grant County PUD No. 2 | EX | Priest Rapids | | | | | | | | | | 185,165 | 185,165 |
| 49 | Great Northern Spokane, LLC. | LU | PURPA | | | | 87 | | | | | 3,098 | | 3,098 |
| 50 | [p] Gridforce Energy Management, LLC | LF | NWPP | | | | 4 | | | | | 207 | | 207 |
| 51 | Guzman Energy, LLC | SF | Tariff 9 | | | | 1,993 | | | | | 125,385 | | 125,385 |
| 52 | Hydro Technology Systems | IU | PURPA | | | | 8,612 | | | | | 386,984 | | 386,984 |
| 53 | Idaho County Power & Light | LU | PURPA | | | | 1,391 | | | | | 69,626 | | 69,626 |
| 54 | [q] Idaho Power Company | OS | Idaho Power Co OATT | | | | | | | | | | 41 | 41 |
| 55 | Idaho Power Company | SF | Tariff 9 | | | | 20,745 | | | | | 1,034,326 | | 1,034,326 |
| 56 | [r] Idaho Power Company | LF | Tariff 9 | | | | 21 | | | | | 705 | | 705 |
| 57 | [s] Idaho Power Company Balancing | LF | Tariff 9 | | | | 5,307 | | | | | | | 0 |
| 58 | [t] Idaho Power Company Balancing | LF | Tariff 9 | | | | 195,573 | | | | | | | 0 |
| 59 | [u] Inland Power & Light Company | RQ | 208 | | | | 127 | | | | | 9,504 | | 9,504 |
| 60 | Macquarie Energy, LLC | SF | Tariff 9 | | | | 8,856 | | | | | 418,395 | | 418,395 |
| 61 | MAG Energy Solutions | SF | Tariff 9 | | | | 1,200 | | | | | 66,600 | | 66,600 |
| 62 | Merrill Lynch Commodities, Inc. | SF | Tariff 9 | | | | 4,400 | | | | | 169,488 | | 169,488 |
| 63 | Morgan Stanley Capital Group | SF | Tariff 9 | | | | 51,305 | | | | | 998,075 | | 998,075 |
| 64 | [v] Morgan Stanley Capital Group | IF | Tariff 9 | | | | 8,593 | | | | | 298,015 | | 298,015 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 65 | NorthWestern Energy | SF | Tariff 9 | | | | 23,046 | | | | | 562,447 | | 562,447 |
| 66 | [w] NorthWestern Energy | LF | NWPP | | | | 14 | | | | | 604 | | 604 |
| 67 | [x] NorthWestern Energy | LF | Tariff 9 | | | | 12,994 | | | | | 560,813 | | 560,813 |
| 68 | [y] NorthWestern Energy | LF | Tariff 9 | | | | 240,773 | | | | | | | 0 |
| 69 | [z] NorthWestern Energy | OS | NorthWestern Energy OATT | | | | | | | | | | 67,305 | 67,305 |
| 70 | PacifiCorp | SF | Tariff 9 | | | | 800 | | | | | 17,775 | | 17,775 |
| 71 | [aa] PacifiCorp | LF | Tariff 9 | | | | 107,068 | | | | | | | 0 |
| 72 | [ab] PacifiCorp | LF | NWPP | | | | 22 | | | | | 878 | | 878 |
| 73 | [ac] PacifiCorp | LF | Tariff 9 | | | | 6 | | | | | (51) | | (51) |
| 74 | [ad] PacifiCorp | OS | PacifiCorp OATT | | | | | | | | | | (28) | (28) |
| 75 | Palouse Wind, LLC | LU | PPA | | | | 303,408 | | | | | 20,916,948 | | 20,916,948 |
| 76 | Pend Oreille County PUD No. 1 | SF | Pend O' | | | | 40,066 | | | | | 1,509,373 | | 1,509,373 |
| 77 | [ae] Pend Oreille County PUD No. 1 | LF | Pend O' | | | | 5,961 | | | | | 225,157 | | 225,157 |
| 78 | Pend Oreille County PUD No. 1 | LF | Pend O' | | | | 11 | | | | | 601 | | 601 |
| 79 | Phillips 66 Energy Trading, LLC | SF | Tariff 9 | | | | 35,845 | | | | | 2,778,890 | | 2,778,890 |
| 80 | Portland General Electric Company | SF | Tariff 9 | | | | 33,500 | | | | | 1,261,358 | | 1,261,358 |
| 81 | [af] Portland General Electric Company | LF | NWPP | | | | 27 | | | | | 1,152 | | 1,152 |
| 82 | [ag] Portland General Electric Company | LF | Tariff 9 | | | | 93 | | | | | 1,712 | | 1,712 |
| 83 | [ah] Portland General Electric Company | OS | Portland General OATT | | | | | | | | | | 2,977 | 2,977 |
| 84 | Powerex Corp | SF | Tariff 9 | | | | 16,445 | | | | | 1,019,800 | | 1,019,800 |
| 85 | Puget Sound Energy | SF | Tariff 9 | | | | 66,487 | | | | | 3,173,642 | | 3,173,642 |
| 86 | [ai] Puget Sound Energy | LF | NWPP | | | | 27 | | | | | 1,152 | | 1,152 |
| 87 | Rainbow Energy Marketing Co. | SF | Tariff 9 | | | | 1,870 | | | | | 67,598 | | 67,598 |
| 88 | Rathdrum Power, LLC | LU | Lancaster | | | | 1,715,535 | | | | | 28,774,400 | | 28,774,400 |
| 89 | Rattlesnake Flat, LLC | LU | PPA | | | | 383,691 | | | | | 11,549,352 | | 11,549,352 |
| 90 | Seattle City Light | SF | Tariff 9 | | | | 9,850 | | | | | 402,354 | | 402,354 |
| 91 | [aj] Seattle City Light | LF | NWPP | | | | 10 | | | | | 387 | | 387 |
| 92 | Sheep Creek Hydro | IU | PURPA | | | | 6,157 | | | | | 284,267 | | 284,267 |
| 93 | Shell Energy | SF | Tariff 9 | | | | 10,900 | | | | | 326,041 | | 326,041 |
| 94 | Snohomish County PUD No. 1 | SF | Tariff 9 | | | | 14,900 | | | | | 338,009 | | 338,009 |
| 95 | Spokane Eco District 1, LLC. | LU | PURPA | | | | 8 | | | | | 309 | | 309 |
| 96 | Tacoma Power | SF | Tariff 9 | | | | 4,240 | | | | | 124,664 | | 124,664 |
| 97 | [ak] Tacoma Power | LF | NWPP | | | | 2 | | | | | 92 | | 92 |
| 98 | The City of Cove | LU | PURPA | | | | 2,196 | | | | | 82,818 | | 82,818 |
| 99 | The Energy Authority | SF | Tariff 9 | | | | 29,881 | | | | | 1,280,787 | | 1,280,787 |
| 100 | TransAlta Energy Marketing | SF | Tariff 9 | | | | 25,503 | | | | | 811,375 | | 811,375 |
| 101 | Turlock Irrigation District | SF | Tariff 9 | | | | 1,214 | | | | | 19,885 | | 19,885 |
| 102 | Vitol Inc. | SF | Tariff 9 | | | | 11,954 | | | | | 561,010 | | 561,010 |
| 103 | [al] Wells Fargo Securities, LLC | OS | NA | | | | | | | | | | (100,880) | (100,880) |
| 104 | Weyns Farms, LLC | LU | PURPA | | | | 739 | | | | | 39,765 | | 39,765 |
| 105 | [am] IntraCompany Generation Services | OS | OATT | | | | | | | | | | 1,252,545 | 1,252,545 |
| 106 | Other - Inadvertent Interchange | EX | | | | | | | 460 | | | | | 0 |
| 107 | [an] California Independent System Operator | OS | Tariff 9 | | | | | | | | | | 5,182,603 | 5,182,603 |
| 108 | [ao] Powerdex Pricing Accrual | SF | Tariff 9 | | | | | | | | | 2,416 | | 2,416 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 109 | [(ao)] Climate Commitment Act Emission Expense | OS | 898 | | | | | | | | | | 209,300 | 209,300 |
| 15 | TOTAL | | | | | | 6,619,942 | 0 | 460 | 0 | 73,824,942 | 157,692,617 | 7,687,375 | 239,204,934 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

FOOTNOTE DATA

| |
|---|
| (a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement. |
| (b) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| 06/26/2023-12/31/2027 ETSR is an import resource associated with an EIM intertie with another EIM BAA, or a CISO intertie with the CISO |
| (c) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Energy Imbalance Charges |
| (d) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| BPA Self Supply for NITSA Customers |
| (e) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement |
| (f) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Ancillary Services - Spinning & Supplemental Reserves |
| (g) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Financially Settled Transmission Losses |
| (h) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| 03/02/2022-12/31/2027 ETSR is an import resource associated with an EIM intertie with another EIM BAA, or a CISO intertie with the CISO |
| (i) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Canadian Entitlement |
| (j) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement |
| (k) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Canadian Entitlement |
| (l) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Energy Imbalance Market Purchases |
| (m) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement. |
| (n) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Non monetary power exchange |
| (o) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Canadian Entitlement |
| (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 |
| 03/02/2022-12/31/2027 ETSR is an import resource associated with an EIM intertie with another EIM BAA, or a CISO intertie with the CISO |
| (t) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| 03/02/2022-12/31/2027 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 |
| DEC Deal for 1/01/2024 - 12/31/2026 |
| (w) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement |
| (x) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Financially Settled Transmission Losses |
| (y) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| 01/26/2022-12/31/2027 ETSR is an import resource associated with an EIM intertie with another EIM BAA, or a CISO intertie with the CISO |
| (z) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Energy Imbalance Charges |
| (aa) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| 01/27/2022-12/31/2027 ETSR is an import resource associated with an EIM intertie with another EIM BAA, or a CISO intertie with the CISO |
| (ab) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement |
| (ac) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Financially Settled Transmission Losses |
| (ad) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Energy Imbalance Charges |
| (ae) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Pend Oreille County PUD contract expires September 30, 2026 |
| (af) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement |
| (ag) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Financially Settled Transmission Losses |
| (ah) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Energy Imbalance Charges |
| (ai) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement |
| (aj) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement |
| (ak) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement |
| (al) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Financial SWAP |
| (am) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Ancillary Services |
| (an) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Energy Imbalance Market Purchases |
| (ao) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| To accrue for missing Powerdex Prices at year end 2025 |
| (ap) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower |
| Expenses for Environmental Credits, 555.3 Unbundled Environmental Credits |

| Name of Respondent:<br>Avista Corporation | This report is:<br>(1) ☑ An Original<br>(2) ☐ A Resubmission | Date of Report:<br>04/17/2026 | Year/Period of Report<br>End of: 2025/ Q4 |
|---|---|---|---|

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

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

| Line No. | Payment By (Company of Public Authority) (Footnote Affiliation) (a) | Energy Received From (Company of Public Authority) (Footnote Affiliation) (b) | Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c) | Statistical Classification (d) | Ferc Rate Schedule of Tariff Number (e) | Point of Receipt (Substation or Other Designation) (f) | Point of Delivery (Substation or Other Designation) (g) | Billing Demand (MW) (h) | TRANSFER OF ENERGY | | REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | Megawatt Hours Received (i) | Megawatt Hours Delivered (j) | Demand Charges ($) (k) | Energy Charges ($) (l) | Other Charges ($) (m) | Total Revenues ($) (k+l+m) (n) |
| 1 | Altop Energy Trading | Bonneville Power Administration | Avista Corporation | NF | FERC Trf No. 8 | | | | 50 | 50 | 397 | | 0 | 397 |
| 2 | Altop Energy Trading | NorthWestern Montana | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 3,105 | 3,105 | 25,615 | | 0 | 25,615 |
| 3 | Altop Energy Trading | NorthWestern Montana | Idaho Power Company | NF | FERC Trf No. 8 | | | | 38 | 38 | 403 | | 0 | 403 |
| 4 | Basin Electric Power Cooperative | Avista Corporation | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 0 | 0 | 2,744 | | 0 | 2,744 |
| 5 | Bonneville Power Administration | Bonneville Power Administration | Bonneville Power Administration | FNO | FERC Trf No. 8 | AVA.BPAT | AVA.SYS | | 2,219,523 | 2,219,523 | 7,873,529 | | [a]1,203,696 | 9,077,225 |
| 6 | Bonneville Power Administration | Bonneville Power Administration | Bonneville Power Administration | OS | RS No. T1110 | | | | 0 | 0 | 0 | | [b]924,000 | 924,000 |
| 7 | Bonneville Power Administration | Bonneville Power Administration | Idaho Power Company | NF | FERC Trf No. 8 | | | | 5,798 | 5,798 | 53,369 | | 0 | 53,369 |
| 8 | Bonneville Power Administration | Bonneville Power Administration | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 64 | 64 | 508 | | 0 | 508 |
| 9 | City of Spokane | City of Spokane | Avista Corporation | OLF | PURPA | | | | 0 | 0 | 0 | | [c]27,973 | 27,973 |
| 10 | Consolidated Irrigation | Bonneville Power Administration | Consolidated Irrigation | LFP | FERC Trf No. 8 | AVA.BPAT | AVA.SYS | 4 | 7,624 | 7,624 | 32,980 | | [d]10,562 | 43,542 |
| 11 | Shell Energy | Bonneville Power Administration | Idaho Power Company | NF | FERC Trf No. 8 | | | | 61 | 61 | 1,756 | | 0 | 1,756 |
| 12 | Shell Energy | NorthWestern Montana | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 589 | 589 | 14,331 | | 0 | 14,331 |
| 13 | Shell Energy | PacifiCorp | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 582 | 582 | 16,758 | | 0 | 16,758 |
| 14 | Deep Creek Hydro | Deep Creek Hydro | Avista Corporation | OLF | PURPA | | | | 0 | 0 | 0 | | [e]603 | 603 |
| 15 | Douglas County PUD | Douglas County PUD | Avista Corporation | NF | FERC Trf No. 8 | | | | 28 | 28 | 230 | | [f]2 | 232 |
| 16 | Dynasty Power | Bonneville Power Administration | Idaho Power Company | NF | FERC Trf No. 8 | | | | 25 | 25 | 198 | | 0 | 198 |
| 17 | Dynasty Power | Bonneville Power Administration | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 66 | 66 | 523 | | 0 | 523 |
| 18 | Dynasty Power | Bonneville Power Administration | Avista Corporation | NF | FERC Trf No. 8 | | | | 50 | 50 | 577 | | 0 | 577 |
| 19 | Dynasty Power | NorthWestern Montana | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 1,137 | 1,137 | 14,686 | | 0 | 14,686 |
| 20 | Dynasty Power | NorthWestern Montana | Idaho Power Company | NF | FERC Trf No. 8 | | | | 55 | 55 | 436 | | 0 | 436 |
| 21 | Dynasty Power | Idaho Power Company | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 1,461 | 1,461 | 22,530 | | 0 | 22,530 |
| 22 | Dynasty Power | Idaho Power Company | Bonneville Power Administration | SFP | FERC Trf No. 8 | | | | 2,736 | 2,736 | 24,295 | | 0 | 24,295 |
| 23 | Dynasty Power | Idaho Power Company | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 51 | 51 | 589 | | 0 | 589 |
| 24 | Dynasty Power | Idaho Power Company | PacifiCorp | SFP | FERC Trf No. 8 | | | | 2,176 | 2,176 | 19,322 | | 0 | 19,322 |
| 25 | Dynasty Power | Idaho Power Company | Puget Sound Energy | SFP | FERC Trf No. 8 | | | | 400 | 400 | 3,552 | | 0 | 3,552 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 26 | EDR Trading | Bonneville Power Administration | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 219 | 219 | 1,737 | | 0 | 1,737 |
| 27 | EDR Trading | Bonneville Power Administration | Avista Corporation | NF | FERC Trf No. 8 | | | | 150 | 150 | 1,190 | | 0 | 1,190 |
| 28 | EDR Trading | Avista Corporation | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 0 | 0 | 257 | | 0 | 257 |
| 29 | EPCOR Energy | Bonneville Power Administration | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 0 | 0 | 1,856 | | 0 | 1,856 |
| 30 | Energy Keepers | Bonneville Power Administration | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 300 | 300 | 2,379 | | 0 | 2,379 |
| 31 | Energy Keepers | Bonneville Power Administration | NorthWestern Montana | SFP | FERC Trf No. 8 | | | | 1,200 | 1,200 | 9,510 | | 0 | 9,510 |
| 32 | Energy Keepers | NorthWestern Montana | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 1,283 | 1,283 | 10,325 | | 0 | 10,325 |
| 33 | Energy Keepers | NorthWestern Montana | Bonneville Power Administration | SFP | FERC Trf No. 8 | | | | 9,141 | 9,141 | 50,179 | | 0 | 50,179 |
| 34 | Energy Keepers | NorthWestern Montana | Chelan County PUD | NF | FERC Trf No. 8 | | | | 1,248 | 1,248 | 10,003 | | 0 | 10,003 |
| 35 | Energy Keepers | NorthWestern Montana | Chelan County PUD | SFP | FERC Trf No. 8 | | | | 2,720 | 2,720 | 14,371 | | 0 | 14,371 |
| 36 | Energy Keepers | NorthWestern Montana | Idaho Power Company | NF | FERC Trf No. 8 | | | | 164 | 164 | 1,380 | | 0 | 1,380 |
| 37 | Energy Keepers | NorthWestern Montana | PacifiCorp | NF | FERC Trf No. 8 | | | | 400 | 400 | 3,193 | | 0 | 3,193 |
| 38 | Energy Keepers | NorthWestern Montana | PacifiCorp | SFP | FERC Trf No. 8 | | | | 1,800 | 1,800 | 9,510 | | 0 | 9,510 |
| 39 | Energy Keepers | NorthWestern Montana | Puget Sound Energy | SFP | FERC Trf No. 8 | | | | 1,280 | 1,280 | 7,819 | | 0 | 7,819 |
| 40 | Energy Keepers | Idaho Power Company | Bonneville Power Administration | SFP | FERC Trf No. 8 | | | | 283 | 283 | 1,809 | | 0 | 1,809 |
| 41 | Energy Keepers | Idaho Power Company | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 412 | 412 | 3,289 | | 0 | 3,289 |
| 42 | Energy Keepers | Idaho Power Company | NorthWestern Montana | SFP | FERC Trf No. 8 | | | | 800 | 800 | 6,340 | | 0 | 6,340 |
| 43 | Grant County PUD | Grant County PUD | Grant County PUD | OLF | RS No. 104 | Stratford | Coulee City/Wilson Creek | | 91,904 | 91,904 | 26,835 | | 0 | 26,835 |
| 44 | Guzman Energy | Bonneville Power Administration | Idaho Power Company | NF | FERC Trf No. 8 | | | | 375 | 375 | 3,143 | | 0 | 3,143 |
| 45 | Guzman Energy | Bonneville Power Administration | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 150 | 150 | 1,189 | | 0 | 1,189 |
| 46 | Guzman Energy | NorthWestern Montana | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 249 | 249 | 2,362 | | 0 | 2,362 |
| 47 | Guzman Energy | NorthWestern Montana | Idaho Power Company | NF | FERC Trf No. 8 | | | | 345 | 345 | 3,396 | | 0 | 3,396 |
| 48 | Guzman Energy | Idaho Power Company | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 1,896 | 1,896 | 46,688 | | 0 | 46,688 |
| 49 | Guzman Energy | Idaho Power Company | Bonneville Power Administration | SFP | FERC Trf No. 8 | | | | 257 | 257 | 28,403 | | 0 | 28,403 |
| 50 | Guzman Energy | Idaho Power Company | NorthWestern Montana | SFP | FERC Trf No. 8 | | | | 1,040 | 1,040 | 8,242 | | 0 | 8,242 |
| 51 | Guzman Energy | Avista Corporation | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 151 | 151 | 1,282 | | 0 | 1,282 |
| 52 | Guzman Energy | Avista Corporation | Idaho Power Company | NF | FERC Trf No. 8 | | | | 29 | 29 | 230 | | 0 | 230 |
| 53 | Guzman Energy | Avista Corporation | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 50 | 50 | 425 | | 0 | 425 |
| 54 | Hydro Tech Industries | Meyers Falls | Avista Corporation | OLF | PURPA | | | | 0 | 0 | 0 | | [a]5,772 | 5,772 |
| 55 | Idaho Power Company | Bonneville Power Administration | Idaho Power Company | LFP | FERC Trf No. 8 | MIDC | LOLO | 100 | 183,340 | 183,340 | 3,298,000 | | 0 | 3,298,000 |
| 56 | Idaho Power Company | Bonneville Power Administration | Idaho Power Company | LFP | FERC Trf No. 8 | AVA.BPAT | LOLO | 100 | 64,708 | 64,708 | 3,298,000 | | 0 | 3,298,000 |
| 57 | Idaho Power Company | Bonneville Power Administration | Idaho Power Company | NF | FERC Trf No. 8 | | | | 430 | 430 | 3,814 | | 0 | 3,814 |
| 58 | Idaho Power Company | Bonneville Power Administration | Idaho Power Company | SFP | FERC Trf No. 8 | | | | 25 | 25 | (4,500) | | 0 | (4,500) |
| 59 | Kootenai Renewable Energy | Avista Corporation | Idaho Power Company | LFP | FERC Trf No. 8 | AVA.SYS | LOLO | 3 | 18,981 | 18,981 | 78,841 | | [b]22,549 | 101,390 |
| 60 | Kootenai Renewable Energy | Avista Corporation | NorthWestern Montana | LFP | FERC Trf No. 8 | | | | 4,469 | 4,469 | 20,099 | | 0 | 20,099 |
| 61 | MAG Energy Solutions | Bonneville Power Administration | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 226 | 226 | 7,946 | | 0 | 7,946 |
| 62 | MAG Energy Solutions | NorthWestern Montana | PacifiCorp | NF | FERC Trf No. 8 | | | | 28 | 28 | 1,784 | | 0 | 1,784 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 63 | MAG Energy Solutions | Idaho Power Company | PacifiCorp | SFP | FERC Trf No. 8 | | | | 2,630 | 2,630 | 87,514 | | 0 | 87,514 |
| 64 | MAG Energy Solutions | Idaho Power Company | Puget Sound Energy | SFP | FERC Trf No. 8 | | | | 320 | 320 | 7,652 | | 0 | 7,652 |
| 65 | MAG Energy Solutions | Idaho Power Company | Avista Corporation | SFP | FERC Trf No. 8 | | | | 400 | 400 | 9,540 | | 0 | 9,540 |
| 66 | Macquarie Energy | Bonneville Power Administration | Idaho Power Company | NF | FERC Trf No. 8 | | | | 555 | 555 | 4,401 | | 0 | 4,401 |
| 67 | Macquarie Energy | Bonneville Power Administration | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 700 | 700 | 5,646 | | 0 | 5,646 |
| 68 | Macquarie Energy | NorthWestern Montana | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 7,969 | 7,969 | 81,965 | | 0 | 81,965 |
| 69 | Macquarie Energy | NorthWestern Montana | Bonneville Power Administration | SFP | FERC Trf No. 8 | | | | 12,320 | 12,320 | 69,503 | | 0 | 69,503 |
| 70 | Macquarie Energy | NorthWestern Montana | Idaho Power Company | NF | FERC Trf No. 8 | | | | 546 | 546 | 8,361 | | 0 | 8,361 |
| 71 | Macquarie Energy | NorthWestern Montana | Idaho Power Company | SFP | FERC Trf No. 8 | | | | 800 | 800 | 31,710 | | 0 | 31,710 |
| 72 | Macquarie Energy | Idaho Power Company | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 803 | 803 | 8,466 | | 0 | 8,466 |
| 73 | Macquarie Energy | Idaho Power Company | Bonneville Power Administration | SFP | FERC Trf No. 8 | | | | 672 | 672 | 3,915 | | 0 | 3,915 |
| 74 | Macquarie Energy | Avista Corporation | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 400 | 400 | 3,172 | | 0 | 3,172 |
| 75 | Mercuria Energy | Bonneville Power Administration | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 159 | 159 | 1,626 | | 0 | 1,626 |
| 76 | Mercuria Energy | Idaho Power Company | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 2,226 | 2,226 | 26,191 | | 0 | 26,191 |
| 77 | Morgan Stanley | Bonneville Power Administration | Idaho Power Company | NF | FERC Trf No. 8 | | | | 71 | 71 | 708 | | 0 | 708 |
| 78 | Morgan Stanley | Bonneville Power Administration | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 484 | 484 | 4,920 | | 0 | 4,920 |
| 79 | Morgan Stanley | NorthWestern Montana | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 59,347 | 59,347 | 619,678 | | 0 | 619,678 |
| 80 | Morgan Stanley | NorthWestern Montana | Bonneville Power Administration | SFP | FERC Trf No. 8 | | | | 76,733 | 76,733 | 615,546 | | 0 | 615,546 |
| 81 | Morgan Stanley | NorthWestern Montana | Idaho Power Company | NF | FERC Trf No. 8 | | | | 1,632 | 1,632 | 16,252 | | 0 | 16,252 |
| 82 | Morgan Stanley | NorthWestern Montana | Idaho Power Company | SFP | FERC Trf No. 8 | | | | 771 | 771 | 6,305 | | 0 | 6,305 |
| 83 | Morgan Stanley | NorthWestern Montana | Grant County PUD | NF | FERC Trf No. 8 | | | | 25,549 | 25,549 | 265,614 | | 0 | 265,614 |
| 84 | Morgan Stanley | NorthWestern Montana | Grant County PUD | SFP | FERC Trf No. 8 | | | | 4,539 | 4,539 | 37,805 | | 0 | 37,805 |
| 85 | Morgan Stanley | Grant County PUD | Idaho Power Company | NF | FERC Trf No. 8 | | | | 1,069 | 1,069 | 10,807 | | 0 | 10,807 |
| 86 | Morgan Stanley | Grant County PUD | Idaho Power Company | SFP | FERC Trf No. 8 | | | | 106 | 106 | 908 | | 0 | 908 |
| 87 | Morgan Stanley | Grant County PUD | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 1,678 | 1,678 | 18,209 | | 0 | 18,209 |
| 88 | Morgan Stanley | Grant County PUD | NorthWestern Montana | SFP | FERC Trf No. 8 | | | | 1,200 | 1,200 | 18,862 | | 0 | 18,862 |
| 89 | Morgan Stanley | Idaho Power Company | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 3,742 | 3,742 | 42,258 | | 0 | 42,258 |
| 90 | Morgan Stanley | Idaho Power Company | Bonneville Power Administration | SFP | FERC Trf No. 8 | | | | 315 | 315 | 3,808 | | 0 | 3,808 |
| 91 | Morgan Stanley | Idaho Power Company | Grant County PUD | NF | FERC Trf No. 8 | | | | 93 | 93 | 1,073 | | 0 | 1,073 |
| 92 | Morgan Stanley | Idaho Power Company | Grant County PUD | SFP | FERC Trf No. 8 | | | | 256 | 256 | 3,008 | | 0 | 3,008 |
| 93 | NorthWestern Energy | Bonneville Power Administration | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 2,952 | 2,952 | 24,202 | | 0 | 24,202 |
| 94 | NorthWestern Energy | NorthWestern Montana | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 100 | 100 | 793 | | 0 | 793 |
| 95 | Phillips 66 Energy | Bonneville Power Administration | NorthWestern Montana | SFP | FERC Trf No. 8 | | | | 1,200 | 1,200 | 9,170 | | 0 | 9,170 |
| 96 | Phillips 66 Energy | Bonneville Power Administration | PacifiCorp | SFP | FERC Trf No. 8 | | | | 200 | 200 | 1,097 | | 0 | 1,097 |
| 97 | Phillips 66 Energy | NorthWestern Montana | Bonneville Power Administration | SFP | FERC Trf No. 8 | | | | 120 | 120 | 930 | | 0 | 930 |
| 98 | Phillips 66 Energy | NorthWestern Montana | PacifiCorp | NF | FERC Trf No. 8 | | | | 788 | 788 | 7,074 | | 0 | 7,074 |
| 99 | Phillips 66 Energy | NorthWestern Montana | PacifiCorp | SFP | FERC Trf No. 8 | | | | 11,882 | 11,882 | 89,803 | | 0 | 89,803 |
| 100 | Phillips 66 Energy | PacifiCorp | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 3 | 3 | 24 | | 0 | 24 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 101 | Phillips 66 Energy | PacifiCorp | NorthWestern Montana | SFP | FERC Trf No. 8 | | | | 19,917 | 19,917 | 247,700 | | 0 | 247,700 |
| 102 | Phillips 66 Energy | PacifiCorp | PacifiCorp | NF | FERC Trf No. 8 | | | | 700 | 700 | 5,551 | | 0 | 5,551 |
| 103 | Phillips 66 Energy | PacifiCorp | PacifiCorp | SFP | FERC Trf No. 8 | | | | 10,346 | 10,346 | 169,803 | | 0 | 169,803 |
| 104 | Phillips 66 Energy | Puget Sound Energy | NorthWestern Montana | SFP | FERC Trf No. 8 | | | | 13,681 | 13,681 | 161,009 | | 0 | 161,009 |
| 105 | Phillips 66 Energy | Puget Sound Energy | PacifiCorp | NF | FERC Trf No. 8 | | | | 1,000 | 1,000 | 7,930 | | 0 | 7,930 |
| 106 | Phillips 66 Energy | Puget Sound Energy | PacifiCorp | SFP | FERC Trf No. 8 | | | | 4,500 | 4,500 | 28,548 | | 0 | 28,548 |
| 107 | Phillips 66 Energy | Grant County PUD | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 130 | 130 | 1,327 | | 0 | 1,327 |
| 108 | Phillips 66 Energy | Grant County PUD | NorthWestern Montana | SFP | FERC Trf No. 8 | | | | 3,239 | 3,239 | 22,309 | | 0 | 22,309 |
| 109 | Phillips 66 Energy | Grant County PUD | PacifiCorp | SFP | FERC Trf No. 8 | | | | 548 | 548 | 3,777 | | 0 | 3,777 |
| 110 | Phillips 66 Energy | Idaho Power Company | Bonneville Power Administration | LFP | FERC Trf No. 8 | LOLO | AVA.BPAT | 50 | 63,646 | 63,646 | 412,250 | | 0 | 412,250 |
| 111 | Phillips 66 Energy | Idaho Power Company | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 158 | 158 | 1,877 | | 0 | 1,877 |
| 112 | Phillips 66 Energy | Idaho Power Company | Bonneville Power Administration | SFP | FERC Trf No. 8 | | | | 23,461 | 23,461 | 517,330 | | 0 | 517,330 |
| 113 | Phillips 66 Energy | Idaho Power Company | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 50 | 50 | 397 | | 0 | 397 |
| 114 | Phillips 66 Energy | Idaho Power Company | NorthWestern Montana | SFP | FERC Trf No. 8 | | | | 24,918 | 24,918 | 147,867 | | 0 | 147,867 |
| 115 | Phillips 66 Energy | Idaho Power Company | PacifiCorp | SFP | FERC Trf No. 8 | | | | 168,156 | 168,156 | 1,256,934 | | 0 | 1,256,934 |
| 116 | Phillips 66 Energy | Idaho Power Company | Portland General Electric | SFP | FERC Trf No. 8 | | | | 175 | 175 | 1,398 | | 0 | 1,398 |
| 117 | Phillips 66 Energy | Idaho Power Company | Avista Corporation | SFP | FERC Trf No. 8 | | | | 244 | 244 | 1,569 | | 0 | 1,569 |
| 118 | Phillips 66 Energy | Chelan County PUD | NorthWestern Montana | SFP | FERC Trf No. 8 | | | | 6,175 | 6,175 | 44,438 | | 0 | 44,438 |
| 119 | Phillips 66 Energy | Portland General Electric | NorthWestern Montana | SFP | FERC Trf No. 8 | | | | 2,100 | 2,100 | 15,047 | | 0 | 15,047 |
| 120 | Phillips 66 Energy | Portland General Electric | PacifiCorp | SFP | FERC Trf No. 8 | | | | 200 | 200 | 1,228 | | 0 | 1,228 |
| 121 | Phillips 66 Energy | Portland General Electric | Avista Corporation | SFP | FERC Trf No. 8 | | | | 400 | 400 | 2,171 | | 0 | 2,171 |
| 122 | Phillips 66 Energy | Avista Corporation | NorthWestern Montana | SFP | FERC Trf No. 8 | | | | 6,402 | 6,402 | 186,530 | | 0 | 186,530 |
| 123 | Phillips 66 Energy | Avista Corporation | PacifiCorp | SFP | FERC Trf No. 8 | | | | 3,000 | 3,000 | 18,237 | | 0 | 18,237 |
| 124 | PacifiCorp | Bonneville Power Administration | PacifiCorp | NF | FERC Trf No. 8 | | | | 2,700 | 2,700 | 22,553 | | 0 | 22,553 |
| 125 | PacifiCorp | PacifiCorp | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 2,999 | 2,999 | 27,264 | | 0 | 27,264 |
| 126 | PacifiCorp | PacifiCorp | Idaho Power Company | NF | FERC Trf No. 8 | | | | 519 | 519 | 5,948 | | 0 | 5,948 |
| 127 | PacifiCorp | PacifiCorp | PacifiCorp | NF | FERC Trf No. 8 | | | | 935 | 935 | 8,504 | | 0 | 8,504 |
| 128 | PacifiCorp | PacifiCorp | PacifiCorp | OLF | RS No. 182 | Dry Gulch | Dry Gulch | | 41,690 | 41,690 | 194,990 | | 0 | 194,990 |
| 129 | PacifiCorp | Idaho Power Company | PacifiCorp | NF | FERC Trf No. 8 | | | | 2,685 | 2,685 | 24,016 | | 0 | 24,016 |
| 130 | PacifiCorp | Idaho Power Company | PacifiCorp | SFP | FERC Trf No. 8 | | | | 757 | 757 | 37,913 | | 0 | 37,913 |
| 131 | PacifiCorp | Avista Corporation | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 0 | 0 | 198 | | 0 | 198 |
| 132 | Portland General Electric | Bonneville Power Administration | Avista Corporation | NF | FERC Trf No. 8 | | | | 200 | 200 | 1,713 | | 0 | 1,713 |
| 133 | Portland General Electric | NorthWestern Montana | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 5,912 | 5,912 | 53,337 | | 0 | 53,337 |
| 134 | Portland General Electric | Idaho Power Company | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 392 | 392 | 3,410 | | 0 | 3,410 |
| 135 | Avangrid Renewables | NorthWestern Montana | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 2,517 | 2,517 | 20,356 | | 0 | 20,356 |
| 136 | Avangrid Renewables | Idaho Power Company | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 150 | 150 | 1,190 | | 0 | 1,190 |
| 137 | Puget Sound Energy | Bonneville Power Administration | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 175 | 175 | 1,388 | | 0 | 1,388 |
| 138 | Puget Sound Energy | NorthWestern Montana | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 4,694 | 4,694 | 39,029 | | 0 | 39,029 |
| 139 | Puget Sound Energy | NorthWestern Montana | Bonneville Power Administration | SFP | FERC Trf No. 8 | | | | 6,527 | 6,527 | 34,616 | | 0 | 34,616 |
| 140 | Puget Sound Energy | NorthWestern Montana | Puget Sound Energy | NF | FERC Trf No. 8 | | | | 25 | 25 | 198 | | 0 | 198 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 141 | Powerex | Bonneville Power Administration | Bonneville Power Administration | LFP | FERC Trf No. 8 | | | | 270 | 270 | 4,920 | | 0 | 4,920 |
| 142 | Powerex | Bonneville Power Administration | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 241 | 241 | 1,951 | | 0 | 1,951 |
| 143 | Powerex | Bonneville Power Administration | Chelan County PUD | LFP | FERC Trf No. 8 | | | | 114 | 114 | 2,077 | | 0 | 2,077 |
| 144 | Powerex | Bonneville Power Administration | Chelan County PUD | NF | FERC Trf No. 8 | | | | 11 | 11 | 89 | | 0 | 89 |
| 145 | Powerex | Bonneville Power Administration | Idaho Power Company | LFP | FERC Trf No. 8 | AVA.BPAT | LOLO | 137 | 65,767 | 65,767 | 2,004,078 | | 0 | 2,004,078 |
| 146 | Powerex | Bonneville Power Administration | Idaho Power Company | NF | FERC Trf No. 8 | | | | 1,677 | 1,677 | 15,874 | | 0 | 15,874 |
| 147 | Powerex | Bonneville Power Administration | Idaho Power Company | SFP | FERC Trf No. 8 | | | | 525 | 525 | 3,332 | | 0 | 3,332 |
| 148 | Powerex | Bonneville Power Administration | NorthWestern Montana | LFP | FERC Trf No. 8 | | | | 4,726 | 4,726 | 140,939 | | 0 | 140,939 |
| 149 | Powerex | Bonneville Power Administration | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 709 | 709 | 6,805 | | 0 | 6,805 |
| 150 | Powerex | Bonneville Power Administration | NorthWestern Montana | SFP | FERC Trf No. 8 | | | | 265 | 265 | 1,682 | | 0 | 1,682 |
| 151 | Powerex | Bonneville Power Administration | PacifiCorp | LFP | FERC Trf No. 8 | | | | 314 | 314 | 9,311 | | 0 | 9,311 |
| 152 | Powerex | Bonneville Power Administration | PacifiCorp | SFP | FERC Trf No. 8 | | | | 336 | 336 | 2,132 | | 0 | 2,132 |
| 153 | Powerex | NorthWestern Montana | Bonneville Power Administration | LFP | FERC Trf No. 8 | | | | 44,352 | 44,352 | 1,348,193 | | 0 | 1,348,193 |
| 154 | Powerex | NorthWestern Montana | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 1,141 | 1,141 | 9,107 | | 0 | 9,107 |
| 155 | Powerex | NorthWestern Montana | Bonneville Power Administration | SFP | FERC Trf No. 8 | | | | 795 | 795 | 5,045 | | 0 | 5,045 |
| 156 | Powerex | PacifiCorp | Bonneville Power Administration | LFP | FERC Trf No. 8 | | | | 59 | 59 | 1,075 | | 0 | 1,075 |
| 157 | Powerex | Idaho Power Company | Bonneville Power Administration | LFP | FERC Trf No. 8 | | | | 43,483 | 43,483 | 949,080 | | 0 | 949,080 |
| 158 | Powerex | Idaho Power Company | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 1,688 | 1,688 | 13,548 | | 0 | 13,548 |
| 159 | Powerex | Idaho Power Company | Bonneville Power Administration | SFP | FERC Trf No. 8 | | | | 197 | 197 | 1,250 | | 0 | 1,250 |
| 160 | Powerex | Idaho Power Company | Chelan County PUD | LFP | FERC Trf No. 8 | | | | 3,026 | 3,026 | 58,585 | | 0 | 58,585 |
| 161 | Rainbow Energy Marketing | Bonneville Power Administration | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 219 | 219 | 3,315 | | 0 | 3,315 |
| 162 | Rainbow Energy Marketing | Avista Corporation | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 50 | 50 | 397 | | 0 | 397 |
| 163 | Seattle City Light | Seattle City Light | Grant County PUD | LFP | FERC Trf No. 8 | | | | 25,347 | 25,347 | 186,390 | | 0 | 186,390 |
| 164 | Seattle City Light | Seattle City Light | Grant County PUD | OLF | FERC Trf No. 8 | | | | 838 | 838 | 26,627 | | 0 | 26,627 |
| 165 | Seattle City Light | NorthWestern Montana | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 75 | 75 | 595 | | 0 | 595 |
| 166 | Spokane Tribe | Bonneville Power Administration | Spokane Tribe | FNO | FERC Trf No. 8 | AVA.BPAT | AVA.SYS | | 3,469 | 3,469 | 12,395 | | 7,539 | 19,934 |
| 167 | The Energy Authority | Bonneville Power Administration | Idaho Power Company | NF | FERC Trf No. 8 | | | | 592 | 592 | 5,106 | | 0 | 5,106 |
| 168 | The Energy Authority | Bonneville Power Administration | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 389 | 389 | 3,583 | | 0 | 3,583 |
| 169 | The Energy Authority | NorthWestern Montana | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 4,333 | 4,333 | 36,177 | | 0 | 36,177 |
| 170 | The Energy Authority | NorthWestern Montana | Bonneville Power Administration | SFP | FERC Trf No. 8 | | | | 1,104 | 1,104 | 3,924 | | 0 | 3,924 |
| 171 | The Energy Authority | NorthWestern Montana | Idaho Power Company | NF | FERC Trf No. 8 | | | | 675 | 675 | 5,822 | | 0 | 5,822 |
| 172 | The Energy Authority | Idaho Power Company | Bonneville Power Administration | SFP | FERC Trf No. 8 | | | | 162 | 162 | 576 | | 0 | 576 |
| 173 | The Energy Authority | Avista Corporation | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 63 | 63 | 659 | | 0 | 659 |
| 174 | TransAlta Energy Marketing | Bonneville Power Administration | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 493 | 493 | 3,909 | | 0 | 3,909 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 175 | TransAlta Energy Marketing | NorthWestern Montana | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 2,055 | 2,055 | 16,661 | | 0 | 16,661 |
| 176 | TransAlta Energy Marketing | Idaho Power Company | Bonneville Power Administration | NF | FERC Trf No. 8 | | | | 60 | 60 | 476 | | 0 | 476 |
| 177 | Tenaska Power Services | Avista Corporation | NorthWestern Montana | NF | FERC Trf No. 8 | | | | 0 | 0 | 1,071 | | 0 | 1,071 |
| 178 | Tacoma Power | Tacoma Power | Grant County PUD | LFP | FERC Trf No. 8 | | | | 25,326 | 25,326 | 259,717 | | 0 | 259,717 |
| 179 | Tacoma Power | Tacoma Power | Grant County PUD | OLF | FERC Trf No. 8 | | | | 837 | 837 | 37,102 | | 0 | 37,102 |
| 180 | East Greenacres | Bonneville Power Administration | East Greenacres | LFP | FERC Trf No. 8 | AVA.BPAT | AVA.SYS | 3 | 4,734 | 4,734 | 17,314 | | [(a)]8,198 | 25,512 |
| 35 | TOTAL | | | | | | | 397 | 3,527,542 | 3,527,542 | 26,151,909 | 0 | 2,210,894 | 28,362,803 |

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 |
| Ancillary services |
| (g) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers |
| Use of facilities |
| (h) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers |
| Ancillary services |
| (i) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers |
| Ancillary services |
| (j) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers |
| Ancillary services |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:
   FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter ""TOTAL"" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | TRANSFER OF ENERGY MegaWatt Hours Received (c) | MegaWatt Hours Delivered (d) | EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e) | Energy Charges ($) (f) | Other Charges ($) (g) | Total Cost of Transmission ($) (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | Bonneville Power Admin | LFP | | | 1,422,051 | | | 1,422,051 |
| 2 | Bonneville Power Admin | LFP | | | 12,953,898 | | [a] 2,482,506 | 15,436,404 |
| 3 | Bonneville Power Admin | OS | | | | | [b] 71,724 | 71,724 |
| 4 | Bonneville Power Admin | FNS | | | 2,312,008 | | [c] 473,544 | 2,785,552 |
| 5 | Bonneville Power Admin | NF | 26,330 | 26,330 | | 160,601 | | 160,601 |
| 6 | Energy Keepers, Inc | NF | 10,129 | 10,129 | | 45,384 | | 45,384 |
| 7 | Grant County PUD | LFP | | | 2,620,390 | | | 2,620,390 |
| 8 | Idaho Power Company | NF | 597 | 597 | | 3,845 | | 3,845 |
| 9 | Kootenai Electric Coop | LFP | | | 64,208 | | | 64,208 |
| 10 | Northern Lights, Inc | LFP | | | 141,711 | | | 141,711 |
| 11 | NorthWestern Energy | NF | 34,558 | 34,558 | | 210,672 | | 210,672 |
| 12 | NorthWestern Energy | SFP | | | 283,273 | | [d] 9,673 | 292,946 |
| 13 | NorthWestern Energy | LFP | | | 5,340,817 | | [e] 95,983 | 5,436,800 |
| 14 | Portland General Elect | NF | 1,870 | 1,870 | | 4,348 | | 4,348 |
| 15 | Portland General Elect | LFP | | | 1,359,114 | | [f] 86,185 | 1,445,299 |
| 16 | Seattle City Light | NF | 19,918 | 19,918 | | 35,485 | | 35,485 |
| 17 | Snohomish County PUD | NF | 37,352 | 37,352 | | 66,641 | | 66,641 |
| | TOTAL | | 130,754 | 130,754 | 26,497,470 | 526,976 | 3,219,615 | 30,244,061 |

| 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 |
| (f) Concept: OtherChargesTransmissionOfElectricityByOthers |
| Ancillary Services |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

| Line No. | Description (a) | Amount (b) |
|---|---|---|
| 1 | Industry Association Dues | 670,007 |
| 2 | Nuclear Power Research Expenses | |
| 3 | Other Experimental and General Research Expenses | |
| 4 | Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities | 922,971 |
| 5 | Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000 | |
| 6 | Board of Director Activities | 1,717,539 |
| 7 | Community Relations | 635,390 |
| 8 | Compliance | 49,765 |
| 9 | Education, Information & Training | 523,052 |
| 10 | Misc. Employee Expenses | 87,538 |
| 11 | Misc. Labor | 268,105 |
| 12 | Misc. Legal, Professional, and General Services | 193,141 |
| 13 | Misc. Transportation | 87,891 |
| 14 | Other Misc. Expenses <$5k | 194,397 |
| 46 | TOTAL | 5,349,796 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

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

1. Report in section A for the year the amounts for: (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year. Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
   In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
   For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service lives, show in column (f) the type of mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

### A. Summary of Depreciation and Amortization Charges

| Line No. | Functional Classification (a) | Depreciation Expense (Account 403) (b) | Depreciation Expense for Asset Retirement Costs (Account 403.1) (c) | Amortization of Limited Term Electric Plant (Account 404) (d) | Amortization of Other Electric Plant (Acc 405) (e) | Total (f) |
|---|---|---|---|---|---|---|
| 1 | Intangible Plant | | | 1,304,517 | | 1,304,517 |
| 2 | Steam Production Plant | 26,684,212 | | | | 26,684,212 |
| 3 | Nuclear Production Plant | | | | | |
| 4 | Hydraulic Production Plant-Conventional | 18,505,074 | | | | 18,505,074 |
| 5 | Hydraulic Production Plant-Pumped Storage | | | | | |
| 5.1 | Solar Production Plant | | | | | |
| 5.2 | Wind Production Plant | | | | | |
| 5.3 | Other Renewable Production Plant | | | | | |
| 6 | Other Production Plant | 10,462,645 | | | | 10,462,645 |
| 7 | Transmission Plant | 26,436,040 | | | | 26,436,040 |
| 8 | Distribution Plant | 67,566,671 | | | | 67,566,671 |
| 9 | Regional Transmission and Market Operation | | | | | |
| 9.1 | Energy Storage Plant | 179,519 | | | | 179,519 |
| 10 | General Plant | 10,851,790 | | 334,425 | | 11,186,215 |
| 11 | Common Plant-Electric | 19,699,927 | | 37,195,509 | | 56,895,436 |
| 12 | TOTAL | 180,385,878 | | 38,834,451 | | 219,220,329 |

### 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.ID | 19.962 | 75 years | (3)% | 3.12% | S1.5 | 6 years |
| 15 | 311.WA | 37.651 | 75 years | (3)% | 3.81% | S1.5 | 4 years |
| 16 | 312.ID | 32.521 | 55 years | (3)% | 3.77% | R1 | 6 years |
| 17 | 312.WA | 57.545 | 55 years | (3)% | 4.26% | R1 | 4 years |
| 18 | 313.ID | 0.001 | 50 years | (3)% | 16.04% | R2.5 | 6 years |
| 19 | 313.WA | 0.002 | 50 years | (3)% | 23.02% | R2.5 | 4 years |
| 20 | 314.ID | 9.034 | 37 years | (3)% | 4.29% | R0.5 | 6 years |
| 21 | 314.WA | 17.006 | 37 years | (3)% | 7.42% | R0.5 | 4 years |
| 22 | 315.ID | 3.804 | 50 years | (3)% | 4.42% | S1 | 6 years |
| 23 | 315.WA | 7.227 | 50 years | (3)% | 6.15% | S1 | 4 years |
| 24 | 316.ID | 3.627 | 60 years | (3)% | 2.67% | R2 | 6 years |
| 25 | 316.WA | 6.84 | 60 years | (3)% | 4.47% | R2 | 4 years |
| 26 | 392.ID | 0.044 | 17 years | 10% | 4.73% | L2 | 0 years |
| 27 | 392.WA | 0.082 | 17 years | 10% | 4.73% | L2 | 0 years |
| 28 | 394.ID | 0.04 | 20 years | 0% | 5% | SQ | 0 years |
| 29 | 394.WA | 0.074 | 20 years | 0% | 5% | SQ | 0 years |
| 30 | 396.ID | 0.044 | 24 years | 0% | 4.84% | S0 | 0 years |
| 31 | 396.WA | 0.082 | 24 years | 0% | 4.84% | S0 | 0 years |
| 32 | Subtotal | 195.585 | | | | | |
| 33 | Colstrip No. 4 | | | | | | |
| 34 | 311.ID | 19.058 | 75 years | (4)% | 2.75% | S1.5 | 6 years |
| 35 | 311.WA | 35.878 | 75 years | (4)% | 4.14% | S1.5 | 4 years |
| 36 | 312.ID | 22.289 | 55 years | (4)% | 5.15% | R1 | 6 years |
| 37 | 312.WA | 38.395 | 55 years | (4)% | 7.25% | R1 | 4 years |
| 38 | 313.ID | 0.319 | 50 years | (4)% | 5.91% | R2.5 | 6 years |
| 39 | 313.WA | 0.578 | 50 years | (4)% | 0% | R2.5 | 4 years |
| 40 | 314.ID | 5.998 | 37 years | (4)% | 7.49% | R0.5 | 6 years |
| 41 | 314.WA | 11.301 | 37 years | (4)% | 11.48% | R0.5 | 4 years |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 42 | 315.ID | 2.902 | 50 years | (4)% | 4.88% | S1 | 6 years |
| 43 | 315.WA | 5.388 | 50 years | (4)% | 6.74% | S1 | 4 years |
| 44 | 316.ID | 1.882 | 60 years | (4)% | 2.88% | R2 | 6 years |
| 45 | 316.WA | 3.526 | 60 years | (4)% | 4.87% | R2 | 4 years |
| 46 | 392.ID | 0.043 | 17 years | 10% | 4.73% | L2 | 0 years |
| 47 | 392.WA | 0.079 | 17 years | 10% | 4.73% | L2 | 0 years |
| 48 | 394.ID | 0.048 | 20 years | 0% | 5% | SQ | 0 years |
| 49 | 394.WA | 0.089 | 20 years | 0% | 5% | SQ | 0 years |
| 50 | 396.ID | 0.044 | 24 years | 0% | 4.84% | S0 | 0 years |
| 51 | 396.WA | 0.082 | 24 years | 0% | 4.84% | S0 | 0 years |
| 52 | Subtotal | 146.77 | | | | | |
| 53 | Kettle Falls | | | | | | |
| 54 | 310 | 0.427 | | | 0.53% | SQ | 17 years |
| 55 | 311 | 29.021 | 75 years | (5)% | 1.38% | S1.5 | 16 years |
| 56 | 312 | 79.932 | 55 years | (5)% | 2.62% | R1 | 16 years |
| 57 | 314 | 18.754 | 37 years | (5)% | 2.79% | R0.5 | 14 years |
| 58 | 315 | 12.605 | 50 years | (5)% | 3.13% | S1 | 15 years |
| 59 | 315.1 | 0 | 5 years | 0% | 20% | SQ | |
| 60 | 315.2 | 0.252 | 5 years | 0% | 20% | SQ | 3 years |
| 61 | 315.3 | 0.424 | 15 years | 0% | 6.67% | SQ | 7 years |
| 62 | 316 | 2.667 | 60 years | (5)% | 1.52% | R2 | 16 years |
| 63 | Subtotal | 158.303 | | | | | |
| 64 | HYDRO PLANT | | | | | | |
| 65 | Cabinet Gorge | | | | | | |
| 66 | 330 | 9.395 | 100 years | | 1.85% | R4 | 34 years |
| 67 | 331 | 29.768 | 55 years | (13)% | 1.96% | R1.5 | 41 years |
| 68 | 332 | 114.799 | 65 years | (13)% | 1.87% | R1 | 41 years |
| 69 | 333 | 48.138 | 70 years | (13)% | 2.34% | S0 | 40 years |
| 70 | 334 | 40.586 | 40 years | (13)% | 2.74% | S0.5 | 33 years |
| 71 | 334.1 | 0.218 | 5 years | 0% | 20% | SQ | 3 years |
| 72 | 334.2 | 0.008 | 5 years | 0% | 20% | SQ | 1 year |
| 73 | 334.3 | 1.762 | 15 years | 0% | 6.67% | SQ | 7 years |
| 74 | 335 | 6.631 | 55 years | (13)% | 1.65% | R1 | 42 years |
| 75 | 336 | 1.898 | 60 years | (13)% | 1.27% | S2.5 | 36 years |
| 76 | Subtotal | 253.202 | | | | | |
| 77 | Noxon Rapids | | | | | | |
| 78 | 330 | 30.76 | 100 years | | 1.74% | R4 | 39 years |
| 79 | 331 | 25.648 | 55 years | (21)% | 2.22% | R1.5 | 43 years |
| 80 | 332 | 45.336 | 65 years | (21)% | 1.97% | R1 | 44 years |
| 81 | 333 | 89.37 | 70 years | (21)% | 2.2% | S0 | 43 years |
| 82 | 334 | 22.915 | 40 years | (21)% | 3.55% | S0.5 | 29 years |
| 83 | 334.3 | 0.799 | 15 years | 0% | 6.67% | SQ | 7 years |
| 84 | 335 | 4.616 | 55 years | (21)% | 1.94% | R1 | 42 years |
| 85 | 336 | 0.306 | 60 years | (21)% | 2.25% | S2.5 | 30 years |
| 86 | Subtotal | 219.749 | | | | | |
| 87 | Post Falls | | | | | | |
| 88 | 330 | 2.908 | 90 years | | 1.21% | R4 | 28 years |
| 89 | 331 | 8.334 | 55 years | (4)% | 2.22% | R1.5 | 36 years |
| 90 | 332 | 26.064 | 65 years | (4)% | 2.6% | R1 | 35 years |
| 91 | 333 | 2.238 | 70 years | (4)% | 0.11% | S0 | 32 years |
| 92 | 334 | 3.673 | 40 years | (4)% | 2.52% | S0.5 | 29 years |
| 93 | 334.3 | 0.156 | 15 years | 0% | 6.67% | SQ | 7 years |
| 94 | 335 | 1.053 | 65 years | (4)% | 2.64% | R1 | 36 years |
| 95 | 336 | 0.578 | 60 years | (4)% | 2.52% | S2.5 | 38 years |
| 96 | Subtotal | 45.004 | | | | | |
| 97 | Long Lake | | | | | | |
| 98 | 330 | 0.418 | 90 years | | 0.73% | R4 | 25 years |
| 99 | 331 | 11.784 | 55 years | (6)% | 1.9% | R1.5 | 30 years |
| 100 | 332 | 39.152 | 65 years | (6)% | 1.72% | R1 | 31 years |
| 101 | 333 | 9.217 | 70 years | (6)% | 0.26% | S0 | 29 years |
| 102 | 334 | 7.653 | 40 years | (6)% | 1.6% | S0.5 | 27 years |
| 103 | 334.3 | 0.233 | 15 years | 0% | 6.67% | SQ | 7 years |
| 104 | 335 | 1.067 | 65 years | (6)% | 2.83% | R1 | 32 years |
| 105 | 336 | 0 | | | | | |
| 106 | Subtotal | 69.524 | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 107 | Little Falls | | | | | | |
| 108 | 330 | 4.217 | 90 years | | 1.25% | R4 | 17 years |
| 109 | 331 | 6.218 | 110 years | (5)% | 2.32% | R1.5 | 36 years |
| 110 | 332 | 6.408 | 110 years | (5)% | 1.33% | R1 | 33 years |
| 111 | 333 | 39.345 | 70 years | (5)% | 2.54% | S0 | 34 years |
| 112 | 334 | 14.696 | 40 years | (5)% | 2.99% | S0.5 | 29 years |
| 113 | 334.3 | 0.246 | 15 years | 0% | 6.67% | SQ | 7 years |
| 114 | 335 | 0.554 | 65 years | (5)% | 2.4% | R1 | 34 years |
| 115 | Subtotal | 71.684 | | | | | |
| 116 | Upper Falls | | | | | | |
| 117 | 330 | 0.064 | 100 years | | 0.85% | R4 | 16 years |
| 118 | 331 | 5.128 | 50 years | (6)% | 1.57% | R1.5 | 37 years |
| 119 | 332 | 10.109 | 110 years | (6)% | 1.78% | R1 | 36 years |
| 120 | 333 | 0.774 | 70 years | (6)% | 0.1% | S0 | 35 years |
| 121 | 334 | 7.255 | 40 years | (6)% | 2.98% | S0.5 | 26 years |
| 122 | 334.3 | 0.007 | 15 years | 0% | 6.67% | SQ | 7 years |
| 123 | 335 | 0.217 | 65 years | (6)% | 2.03% | R1 | 32 years |
| 124 | 336 | 0.508 | 60 years | (6)% | 2.48% | S2.5 | 37 years |
| 125 | Subtotal | 24.062 | | | | | |
| 126 | Nine Mile | | | | | | |
| 127 | 330 | 0.011 | 90 years | | 0.58% | R4 | 38 years |
| 128 | 331 | 25.462 | 50 years | (4)% | 2.43% | R1.5 | 36 years |
| 129 | 332 | 30.934 | 65 years | (4)% | 2.84% | R1 | 35 years |
| 130 | 333 | 47.624 | 70 years | (4)% | 3.17% | S0 | 35 years |
| 131 | 334 | 19.835 | 40 years | (4)% | 3.31% | S0.5 | 28 years |
| 132 | 334.3 | 0.394 | 15 years | 0% | 6.67% | SQ | 7 years |
| 133 | 335 | 1.157 | 65 years | (4)% | 2.8% | R1 | 35 years |
| 134 | 336 | 0.595 | 60 years | (4)% | 2.35% | S2.5 | 29 years |
| 135 | Subtotal | 126.01 | | | | | |
| 136 | Monroe Street | | | | | | |
| 137 | 331 | 14.283 | 50 years | (7)% | 2.11% | R1.5 | 42 years |
| 138 | 332 | 10.01 | 110 years | (7)% | 1.9% | R1 | 46 years |
| 139 | 333 | 11.712 | 70 years | (7)% | 2.13% | S0 | 38 years |
| 140 | 334 | 3.263 | 40 years | (7)% | 3.74% | S0.5 | 27 years |
| 141 | 334.3 | 0.076 | 15 years | 0% | 6.67% | SQ | 7 years |
| 142 | 335 | 0.048 | 65 years | (7)% | 2.16% | R1 | 39 years |
| 143 | 336 | 0.05 | 60 years | (7)% | 2.51% | S2.5 | 31 years |
| 144 | Subtotal | 39.441 | | | | | |
| 145 | OTHER PRODUCTION | | | | | | |
| 146 | Northeast Turbine | | | | | | |
| 147 | 341 | 0.759 | 55 years | (7)% | 0.23% | R4 | 14 years |
| 148 | 342 | 0.037 | 55 years | (7)% | 0.58% | R3 | 14 years |
| 149 | 343 | 9.056 | 60 years | (7)% | 0.31% | S2 | 14 years |
| 150 | 344 | 2.857 | 50 years | (7)% | 0.96% | R1 | 13 years |
| 151 | 345 | 1.253 | 30 years | (7)% | 0.09% | S0.5 | 12 years |
| 152 | 345.3 | 0.203 | 15 years | 0% | 6.67% | SQ | 7 years |
| 153 | 346 | 0.399 | 35 years | (7)% | 0.2% | R2 | 12 years |
| 154 | Subtotal | 14.563 | | | | | |
| 155 | Rathdrum Turbine | | | | | | |
| 156 | 341 | 3.667 | 55 years | (7)% | 3.92% | R4 | 13 years |
| 157 | 342 | 1.696 | 55 years | (7)% | 3.52% | R3 | 13 years |
| 158 | 343 | 3.646 | 60 years | (7)% | 1.74% | S2 | 13 years |
| 159 | 344 | 51.682 | 50 years | (7)% | 3.86% | R1 | 12 years |
| 160 | 345 | 4.92 | 30 years | (7)% | 6.61% | S0.5 | 12 years |
| 161 | 345.2 | 0.114 | 5 years | 0% | 20% | SQ | 3 years |
| 162 | 345.3 | 0.084 | 15 years | 0% | 6.67% | SQ | 7 years |
| 163 | 346 | 0.249 | 35 years | (7)% | 5.96% | R2 | 12 years |
| 164 | Subtotal | 66.058 | | | | | |
| 165 | Kettle Falls CT | | | | | | |
| 166 | 341 | 0.013 | 55 years | (1)% | 3.81% | R4 | 17 years |
| 167 | 342 | 0.089 | 55 years | (1)% | 1.35% | R3 | 16 years |
| 168 | 343 | 8.67 | 60 years | (1)% | 1.63% | S2 | 16 years |
| 169 | 344 | 0.234 | 50 years | (1)% | 4.71% | R1 | 16 years |
| 170 | 345 | 0.539 | 30 years | (1)% | 6.23% | S0.5 | 16 years |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 171 | 345.3 | 0.079 | 15 years | 0% | 6.67% | SQ | 7 years |
| 172 | Subtotal | 9.624 | | | | | |
| 173 | Boulder Park | | | | | | |
| 174 | 341 | 1.405 | 55 years | (1)% | 2.63% | R4 | 21 years |
| 175 | 342 | 0.162 | 55 years | (1)% | 4.42% | R3 | 21 years |
| 176 | 343 | 0.021 | 60 years | (1)% | 2.35% | S2 | 20 years |
| 177 | 344 | 32.653 | 50 years | (1)% | 2.25% | R1 | 19 years |
| 178 | 345 | 5.451 | 30 years | (1)% | 4.39% | S0.5 | 17 years |
| 179 | 345.3 | 0.166 | 15 years | 0% | 6.67% | SQ | 7 years |
| 180 | 346 | 0.065 | 35 years | (1)% | 4.52% | R2 | 19 years |
| 181 | Subtotal | 39.923 | | | | | |
| 182 | Coyote Springs 2 | | | | | | |
| 183 | 341 | 11.811 | 55 years | (3)% | 2.52% | R4 | 21 years |
| 184 | 342 | 19.018 | 55 years | (3)% | 2.36% | R3 | 21 years |
| 185 | 344 | 155.914 | 50 years | (3)% | 3.4% | R1 | 20 years |
| 186 | 345 | 18.597 | 30 years | (3)% | 2.46% | S0.5 | 16 years |
| 187 | 345.2 | 0.047 | 5 years | 0% | 20% | SQ | 3 years |
| 188 | 345.3 | 0.58 | 15 years | 0% | 6.67% | SQ | 7 years |
| 189 | 346 | 0.926 | 35 years | (3)% | 4.39% | R2 | 18 years |
| 190 | Subtotal | 206.893 | | | | | |
| 191 | Solar Power | | | | | | |
| 192 | 344 | 0.449 | 25 years | (3)% | 7.11% | S2.5 | 8 years |
| 193 | 345 | 0.033 | 25 years | (3)% | 8.92% | S2.5 | 8 years |
| 194 | Subtotal | 0.482 | | | | | |
| 195 | Lancaster | | | | | | |
| 196 | 342 | 0.092 | 55 years | (3)% | 2.88% | R3 | 19 years |
| 197 | 344 | 0.209 | 50 years | (3)% | 3.17% | R1 | 18 years |
| 198 | 345 | 0.308 | 30 years | (3)% | 5.55% | S0.5 | 17 years |
| 199 | 345.3 | 0.02 | 15 years | 0% | 6.67% | SQ | 7 years |
| 200 | Subtotal | 0.628 | | | | | |
| 201 | TRANSMISSION PLANT | | | | | | |
| 202 | 350 | 23.394 | 80 years | 0% | 1.04% | R4 | 44 years |
| 203 | 351.1 | 0.269 | 5 years | 0% | 20% | SQ | 3 years |
| 204 | 351.2 | 2.877 | 5 years | 0% | 20% | SQ | 3 years |
| 205 | 351.3 | 3.659 | 15 years | 0% | 6.67% | SQ | 7 years |
| 206 | 352 | 41.141 | 65 years | (15)% | 1.76% | S2.5 | 51 years |
| 207 | 353 | 425.681 | 46 years | (10)% | 2.36% | R2 | 35 years |
| 208 | 354 | 17.448 | 80 years | (10)% | 1.09% | R4 | 42 years |
| 209 | 355 | 424.524 | 60 years | (40)% | 2.4% | R2.5 | 49 years |
| 210 | 356 | 204.111 | 60 years | (30)% | 2.53% | R3 | 40 years |
| 211 | 357 | 4.166 | 60 years | 0% | 1.63% | R4 | 45 years |
| 212 | 358 | 7.786 | 50 years | 0% | 2.08% | S3 | 42 years |
| 213 | 359 | 2.689 | 75 years | 0% | 1.23% | R4 | 50 years |
| 214 | Subtotal | 1,157.747 | | | | | |
| 215 | DISTRIBUTION PLANT | | | | | | |
| 216 | 360 | 6.15 | 75 years | 0% | 1.34% | R4 | 67 years |
| 217 | 361 | 46.163 | 63 years | (15)% | 1.72% | S1 | 50 years |
| 218 | 362 | 203.288 | 44 years | (5)% | 2.32% | R1.5 | 32 years |
| 219 | 363.1 | 4.103 | 5 years | 0% | 20% | SQ | |
| 220 | 363.2 | 23.493 | 5 years | 0% | 20% | SQ | 6 years |
| 221 | 363.3 | 9.356 | 15 years | 0% | 6.67% | SQ | 7 years |
| 222 | 364 - WA | 460.466 | 63 years | (60)% | 2.69% | R3 | 49 years |
| 223 | 364 - ID | 227.707 | 63 years | (50)% | 2.48% | R3 | 49 years |
| 224 | 365 - WA | 248.154 | 65 years | (55)% | 2.46% | R3 | 50 years |
| 225 | 365 - ID | 154.064 | 65 years | (55)% | 2.46% | R3 | 50 years |
| 226 | 366 - WA | 135.61 | 65 years | (25)% | 1.82% | S2.5 | 52 years |
| 227 | 366 - ID | 63.647 | 70 years | (25)% | 1.65% | S2.5 | 57 years |
| 228 | 367 - WA | 216.385 | 40 years | (25)% | 2.43% | S1.5 | 31 years |
| 229 | 367 - ID | 98.842 | 40 years | (25)% | 2.43% | S1.5 | 31 years |
| 230 | 368 | 431.906 | 50 years | (5)% | 1.87% | R2.5 | 37 years |
| 231 | 369 | 238.843 | 70 years | (5)% | 0.96% | R2.5 | 56 years |
| 232 | 370 - AN | 0.157 | 12 years | (2)% | 7.86% | L2.5 | 9 years |
| 233 | 370 - ID | 24.836 | 33 years | (2)% | 5.57% | L1.5 | 7 years |
| 234 | 370 - WA | 65.748 | 12 years | (2)% | 7.86% | L2.5 | 9 years |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 235 | 371 | 15.099 | 10 years | 0% | 10.87% | S3 | 7 years |
| 236 | 373 | 57.775 | 34 years | (5)% | 1.58% | S1 | 25 years |
| 237 | 373.4 | 18.123 | 34 years | (5)% | 3.2% | S1 | 26 years |
| 238 | 373.5 | 11.915 | 34 years | (5)% | 2.81% | S1 | 30 years |
| 239 | Subtotal | 2,761.831 | | | | | |
| 240 | ENERGY STORAGE PLANT | | | | | | |
| 241 | 387.03 | 1.851 | 15 years | 0% | 6.8% | SQ | 11 years |
| 242 | Subtotal | 1.851 | | | | | |
| 243 | GENERAL PLANT | | | | | | |
| 244 | 390.1 | 21.801 | 50 years | (5)% | 2.06% | S1 | 45 years |
| 245 | 391 | 0.129 | 15 years | | 6.67% | SQ | 14 years |
| 246 | 391.1 | 0 | 5 years | | 20% | SQ | 3 years |
| 247 | 393 | 0.473 | 25 years | | 4% | SQ | 14 years |
| 248 | 394 | 11.336 | 20 years | | 5% | SQ | 14 years |
| 249 | 395 | 4.337 | 15 years | | 6.67% | SQ | 13 years |
| 250 | 397.1 | 1.679 | 5 years | | 20% | SQ | 3 years |
| 251 | 397.2 | 33.442 | 5 years | | 20% | SQ | 2 years |
| 252 | 397.3 | 27.578 | 15 years | | 6.67% | SQ | 7 years |
| 253 | 398 | 0.242 | 10 years | | 10% | SQ | 5 years |
| 254 | Subtotal | 101.015 | | | | | |
| 255 | MISC POWER EQUIPMENT | | | | | | |
| 256 | 392 | 11.725 | 17 years | | 3.81% | L2.5 | 13 years |
| 257 | 396 | 4.924 | 24 years | | 1.88% | S1 | 14 years |
| 258 | Subtotal | 16.649 | | | | | |
| 259 | Total Company | 5,726.599 | | | | | |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.
3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in columns (f), (g), and (h), expenses incurred during the year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

| | | | | | | EXPENSES INCURRED DURING YEAR | | | | AMORTIZED DURING YEAR | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | CURRENTLY CHARGED TO | | | | | | |
| Line No. | Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a) | Assessed by Regulatory Commission (b) | Expenses of Utility (c) | Total Expenses for Current Year (b) + (c) (d) | Deferred in Account 182.3 at Beginning of Year (e) | Department (f) | Account No. (g) | Amount (h) | Deferred to Account 182.3 (i) | Contra Account (j) | Amount (k) | Deferred in Account 182.3 End of Year (l) |
| 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 | 4,228,876 | 97,080 | 4,325,956 | | Electric | 928 | 4,325,956 | | | | 0 |
| 2 | Washington Utilities and Transportation Commission | | | 0 | | | | | | | | 0 |
| 3 | Electric - Includes annual fee and various other electric dockets (01/01/2025 - 12/31/2026) | 2,716,347 | 626,216 | 3,342,563 | 2,685,949 | Electric | 928 | 3,342,563 | 103,898 | 407 | 1,428,650 | 1,361,197 |
| 4 | Gas - Includes annual fee and various other natural gas dockets (01/01/2025 - 12/31/2026) | 1,122,773 | 143,796 | 1,266,569 | 1,325,374 | Gas | 928 | 1,266,569 | 50,428 | 407 | 724,939 | 650,863 |
| 5 | Idaho Public Utilities Commission | | | 0 | | | | | | | | 0 |
| 6 | Electric - Includes annual fee and various other electric dockets | 729,828 | 248,449 | 978,277 | | Electric | 928 | 978,277 | | | | 0 |
| 7 | Gas - Includes annual fee and various other natural gas dockets | 230,139 | 61,155 | 291,294 | | Gas | 928 | 291,294 | | | | 0 |
| 8 | Public Utility Commission of Oregon | | | 0 | | | | | | | | 0 |
| 9 | Includes annual fees and various other natural gas dockets (01/01/2025 - 12/31/2026) | 780,228 | 220,808 | 1,001,036 | 30,447 | Gas | 928 | 1,001,036 | 30,264 | 407 | 36,337 | 24,374 |
| 10 | Not directly assigned Electric | | 989,087 | 989,087 | | Electric | 928 | 989,087 | | | | 0 |
| 11 | Not directly assigned Natural Gas | | 396,249 | 396,249 | | Gas | 928 | 396,249 | | | | 0 |
| 46 | TOTAL | 9,808,191 | 2,782,840 | 12,591,031 | 4,041,770 | | | 12,591,031 | 184,590 | | 2,189,926 | 2,036,434 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D and D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D and D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:
   Classifications:

A. Electric R, D and D Performed Internally:

1. Generation
   a. hydroelectric
      i. Recreation fish and wildlife
      ii. Other hydroelectric
   b. Fossil-fuel steam
   c. Internal combustion or gas turbine
   d. Nuclear
   e. Solar
   f. Wind
   g. Other renewable
   h. Unconventional generation
   i. Siting and heat rejection
2. Transmission
   a. Overhead
   b. Underground
3. Distribution
4. Regional Transmission and Market Operation
5. Energy Storage
6. Environment (other than equipment)
7. Other (Classify and include items in excess of $50,000.)
8. Total Cost Incurred

B. Electric, R, D and D Performed Externally:

1. Research Support to the electrical Research Council or the Electric Power Research Institute
2. Research Support to Edison Electric Institute
3. Research Support to Nuclear Power Groups
4. Research Support to Others (Classify)
5. Total Cost Incurred

3. Include in column (c) all R, D and D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D and D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by ""Est.""
7. Report separately research and related testing facilities operated by the respondent.

| Line No. | Classification (a) | Description (b) | Costs Incurred Internally Current Year (c) | Costs Incurred Externally Current Year (d) | AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Account (e) | AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Amount (f) | Unamortized Accumulation (g) |
|---|---|---|---|---|---|---|---|
| 1 | A. Electric (3) Distribution | Clean Energy | 1,382,300 | 2,454,843 | 107 | 3,837,143 | 0 |
| 2 | A. Electric (3) Distribution | Clean Energy | 52,943 | 0 | 182 | 52,943 | 0 |
| 3 | A. Electric (3) Distribution | Clean Energy | (105,863) | 56,184 | 186 | (49,679) | 0 |
| 4 | A. Electric (3) Distribution | Clean Energy | (5,033) | 0 | 588 | (5,033) | 0 |
| 5 | A. Electric (3) Distribution | Clean Energy | 0 | 68,946 | 908 | 68,946 | 0 |
| 6 | A. Electric (3) Distribution | Clean Energy | 0 | 1,025 | 909 | 1,025 | 0 |
| 7 | A. Electric (3) Distribution | Clean Energy | 28,919 | 0 | 107 | 28,919 | 0 |
| 8 | A. Electric (6) Other - Testing Lab & Facility | HUB-Morris Center Lab Test Facility | 10,828 | 0 | 182 | 10,828 | 0 |
| 9 | A. Electric (6) Other - Testing Lab & Facility | HUB-Morris Center Lab Test Facility | 149,504 | 72,773 | 107 | 222,277 | 0 |
| 10 | B. Electric (4) Research Support to Others (Distribution) | Distributed Grid Sensor Service | 139 | 0 | 108 | 139 | 0 |
| 11 | B. Electric (4) Research Support to Others (Distribution) | Distributed Grid Sensor Service | 2,653 | 0 | 182 | 2,653 | 0 |
| 12 | B. Electric (4) Research Support to Others (Distribution) | Mid-C Hydro Coordination Study | 7,497 | 0 | 557 | 7,497 | 0 |
| 13 | B. Electric (4) Research Support to Others (Distribution) | Distributed Grid Sensor Service | 6,838 | 2,873 | 557 | 9,711 | 0 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## DISTRIBUTION OF SALARIES AND WAGES

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

| Line No. | Classification (a) | Direct Payroll Distribution (b) | Allocation of Payroll Charged for Clearing Accounts (c) | Total (d) |
|---|---|---|---|---|
| 1 | Electric | | | |
| 2 | Operation | | | |
| 3 | Production | 17,137,025 | | |
| 4 | Transmission | 6,468,933 | | |
| 5 | Regional Market | 0 | | |
| 5.1 | Energy Storage | 0 | | |
| 6 | Distribution | 12,759,377 | | |
| 7 | Customer Accounts | 5,463,443 | | |
| 8 | Customer Service and Informational | 300,905 | | |
| 9 | Sales | 0 | | |
| 10 | Administrative and General | 33,445,952 | | |
| 11 | TOTAL Operation (Enter Total of lines 3 thru 10) | 75,575,635 | | |
| 12 | Maintenance | | | |
| 13 | Production | 5,190,176 | | |
| 14 | Transmission | 1,254,688 | | |
| 15 | Regional Market | 0 | | |
| 15.1 | Energy Storage | 0 | | |
| 16 | Distribution | 4,214,156 | | |
| 17 | Administrative and General | | | |
| 18 | TOTAL Maintenance (Total of lines 13 thru 17) | 10,659,020 | | |
| 19 | Total Operation and Maintenance | | | |
| 20 | Production (Enter Total of lines 3 and 13) | 22,327,201 | | |
| 21 | Transmission (Enter Total of lines 4 and 14) | 7,723,621 | | |
| 22 | Regional Market (Enter Total of Lines 5 and 15) | 0 | | |
| 22.1 | Energy Storage (Enter Total of Lines 5.1 and 15.1) | 0 | | |
| 23 | Distribution (Enter Total of lines 6 and 16) | 16,973,533 | | |
| 24 | Customer Accounts (Transcribe from line 7) | 5,463,443 | | |
| 25 | Customer Service and Informational (Transcribe from line 8) | 300,905 | | |
| 26 | Sales (Transcribe from line 9) | 0 | | |
| 27 | Administrative and General (Enter Total of lines 10 and 17) | 33,445,952 | | |
| 28 | TOTAL Oper. and Maint. (Total of lines 20 thru 27) | 86,234,655 | 10,165,397 | 96,400,052 |
| 29 | Gas | | | |
| 30 | Operation | | | |
| 31 | Production - Manufactured Gas | | | |
| 32 | Production-Nat. Gas (Including Expl. And Dev.) | | | |
| 33 | Other Gas Supply | 1,081,922 | | |
| 34 | Storage, LNG Terminaling and Processing | | | |
| 35 | Transmission | | | |
| 36 | Distribution | 8,191,285 | | |
| 37 | Customer Accounts | 5,035,340 | | |
| 38 | Customer Service and Informational | 257,036 | | |
| 39 | Sales | | | |
| 40 | Administrative and General | 12,605,408 | | |
| 41 | TOTAL Operation (Enter Total of lines 31 thru 40) | 27,170,991 | | |
| 42 | Maintenance | | | |
| 43 | Production - Manufactured Gas | | | |
| 44 | Production-Natural Gas (Including Exploration and Development) | | | |
| 45 | Other Gas Supply | | | |
| 46 | Storage, LNG Terminaling and Processing | | | |
| 47 | Transmission | 2,738,566 | | |
| 48 | Distribution | 3,598,016 | | |
| 49 | Administrative and General | | | |
| 50 | TOTAL Maint. (Enter Total of lines 43 thru 49) | 6,336,582 | | |
| 51 | Total Operation and Maintenance | | | |
| 52 | Production-Manufactured Gas (Enter Total of lines 31 and 43) | | | |

| | | | | |
|---|---|---|---|---|
| 53 | Production-Natural Gas (Including Expl. and Dev.) (Total lines 32, | | | |
| 54 | Other Gas Supply (Enter Total of lines 33 and 45) | 1,081,922 | | |
| 55 | Storage, LNG Terminaling and Processing (Total of lines 31 thru | | | |
| 56 | Transmission (Lines 35 and 47) | 2,738,566 | | |
| 57 | Distribution (Lines 36 and 48) | 11,789,301 | | |
| 58 | Customer Accounts (Line 37) | 5,035,340 | | |
| 59 | Customer Service and Informational (Line 38) | 257,036 | | |
| 60 | Sales (Line 39) | | | |
| 61 | Administrative and General (Lines 40 and 49) | 12,605,408 | | |
| 62 | TOTAL Operation and Maint. (Total of lines 52 thru 61) | 33,507,573 | 2,721,279 | 36,228,852 |
| 63 | Other Utility Departments | | | |
| 64 | Operation and Maintenance | 0 | 0 | 0 |
| 65 | TOTAL All Utility Dept. (Total of lines 28, 62, and 64) | 119,742,228 | 12,886,676 | 132,628,904 |
| 66 | Utility Plant | | | |
| 67 | Construction (By Utility Departments) | | | |
| 68 | Electric Plant | 65,228,524 | 9,787,849 | 75,016,373 |
| 69 | Gas Plant | 17,419,051 | 2,613,811 | 20,032,862 |
| 70 | Other (provide details in footnote): | | | 0 |
| 71 | TOTAL Construction (Total of lines 68 thru 70) | 82,647,575 | 12,401,660 | 95,049,235 |
| 72 | Plant Removal (By Utility Departments) | | | |
| 73 | Electric Plant | 2,727,542 | 211,753 | 2,939,295 |
| 74 | Gas Plant | 885,103 | 68,715 | 953,818 |
| 75 | Other (provide details in footnote): | 0 | 0 | 0 |
| 76 | TOTAL Plant Removal (Total of lines 73 thru 75) | 3,612,645 | 280,468 | 3,893,113 |
| 77 | Other Accounts (Specify, provide details in footnote): | | | |
| 78 | Stores Expense (163) | 3,237,217 | (3,237,217) | 0 |
| 79 | Preliminary Survey and Investigation (183) | 0 | 0 | 0 |
| 80 | Small Tool Expense (184) | 6,338,593 | (6,338,593) | 0 |
| 81 | Miscellaneous Deferred Debits (186) | 1,529,663 | 0 | 1,529,663 |
| 82 | Non-operating Expenses (417) | 637,176 | 0 | 637,176 |
| 83 | Retirement Bonus/SERP/HRA (228) | 107,920 | 0 | 107,920 |
| 84 | Other Income Deductions (426) | 1,358,944 | 0 | 1,358,944 |
| 85 | Employee Incentive Plan (232) | 12,961,598 | (12,961,598) | 0 |
| 86 | DSM Tariff Rider (242600) | 3,031,396 | (3,031,396) | 0 |
| 87 | Incentive/Stock Compensation (238000) | 0 | 0 | 0 |
| 88 | Payroll Equalization Liability (242700) | 36,494,554 | 0 | 36,494,554 |
| 89 | Miscellaneous Deferred Credits (253) | 47,452 | 0 | 47,452 |
| 90 | | | | |
| 91 | | | | |
| 92 | | | | |
| 93 | | | | |
| 94 | | | | |
| 95 | TOTAL Other Accounts | 65,744,513 | (25,568,804) | 40,175,709 |
| 96 | TOTAL SALARIES AND WAGES | 271,746,961 | 0 | 271,746,961 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ 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 | |
|---|---|---|
| 302 | Franchises and Consents | 3,342 |
| 303 | Intangible | 306,202,072 |
| 389 | Land and Land Rights | 15,553,212 |
| 390 | Structures and Improvements | 168,112,216 |
| 391 | Office Furniture and Equipment | 66,999,416 |
| 392 | Transportation Equipment | 14,921,528 |
| 393 | Stores Equipment | 6,916,818 |
| 394 | Tools, Shop & garage Equipment | 18,783,591 |
| 395 | Laboratory Equipment | 1,254,754 |
| 396 | Power Operated Equipment | 2,314,037 |
| 397 | Communications Equipment | 180,792,467 |
| 398 | Miscellaneous Equipment | 1,028,990 |
| 399 | Asset Retirement Cost | 0 |
| | Total Common Plant | 782,882,443 |
| | Const. Work in Progress | 26,203,238 |
| | Total Utility Plant | 809,085,681 |
| | Acc. Prov. for Dep. & Amort. | 341,616,929 |
| | Net Utility Plant | 467,468,752 |

3. Common Expenses allocated to Electric and Gas departments:

| Acct. No. | Description | Total | Electric Dept | Gas Dept | Allocation to Basis of Allocation | Allocated to |
|---|---|---|---|---|---|---|
| 901 | Cust acct/collect supervision | 654,162 | 344,119 | 310,042 | # of Customers | |
| 902 | Meter reading expenses | 2,091,197 | 1,263,713 | 827,484 | # of Customers | |
| 903 | Cust rec & collectn expenses | 34,086,598 | 18,104,743 | 15,981,856 | # of Customers | |
| 904 | Uncollectible accounts | 199,258 | 104,034 | 95,224 | # of Customers | |
| 905 | Misc cust acct expenses | 681,726 | 356,653 | 325,073 | # of Customers | |
| 907 | Cust svce & Info exp supervision | 0 | 0 | 0 | # of Customers | |
| 908 | Cust assistance expenses | 1,064,443 | 643,293 | 421,150 | # of Customers | |
| 909 | Info & instruct advert expenses | 2,516,505 | 1,487,555 | 1,028,949 | # of Customers | |
| 910 | Misc cust serv & info expenses | 226,163 | 118,308 | 107,855 | # 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 | 90,445,714 | 65,064,465 | 25,381,249 | Four Factor | |
| 921 | Office supplies & expenses | 11,260,738 | 8,067,612 | 3,193,126 | Four Factor | |
| 922 | Admin expenses tranf-credit | 0 | 0 | 0 | Four Factor | |
| 923 | Outside services employed | 39,093,719 | 28,006,188 | 11,087,531 | Four Factor | |
| 924 | Property insurance | 7,240,530 | 5,182,729 | 2,057,801 | Four Factor | |
| 925 | Injuries and damages | 30,487,243 | 22,254,676 | 8,232,567 | Four Factor | |
| 926 | Employee pensions&benefits | 193,407,132 | 138,648,986 | 54,758,146 | Four Factor | |
| 927 | Franchise requirement | 0 | 0 | 0 | Four Factor | |
| 928 | Regulatory commission expenses | 3,917,459 | 2,903,100 | 1,014,359 | 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 | 11,587,193 | 8,339,005 | 3,248,188 | Four Factor | |
| 931 | Rents | 1,506,837 | 1,090,149 | 416,688 | Four Factor | |
| 935 | Maint of General plant | 38,843,471 | 28,055,145 | 10,788,326 | Four Factor | |
| 403 | Depreciation | 51,467,144 | 37,233,898 | 14,233,246 | Four Factor | |
| 404 | Amort of LTD term plant | 104,468,521 | 74,828,994 | 29,639,527 | 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: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchase Power, respectively.

| Line No. | Description of Item(s) (a) | Balance at End of Quarter 1 (b) | Balance at End of Quarter 2 (c) | Balance at End of Quarter 3 (d) | Balance at End of Year (e) |
|---|---|---|---|---|---|
| 1 | Energy | | | | |
| 2 | Net Purchases (Account 555) | [a]2,839,991 | [b]3,379,170 | [c]5,140,859 | [d]5,797,765 |
| 2.1 | Net Purchases (Account 555.1) | | | | |
| 3 | Net Sales (Account 447) | [e](1,430,291) | [f](3,471,360) | [g](5,633,870) | [h](8,255,205) |
| 4 | Transmission Rights | | | | |
| 5 | Ancillary Services | 37 | 14,731 | 14,722 | (2,440) |
| 6 | Other Items (list separately) | | | | |
| 7 | Other Charges - MRTU | 28,475 | 138,393 | 142,458 | 140,641 |
| 8 | Other Charges - EIM | (207,987) | (422,857) | (757,632) | (1,176,067) |
| 46 | TOTAL | 1,230,225 | (361,923) | (1,093,463) | (3,495,306) |

FOOTNOTE DATA

(a) Concept: IsoOrRtoSettlementsEnergyNetPurchasesPurchasedPower

CAISO - MRTU Purchases = -$7,619

CAISO - EIM Purchases = $2,847,610

(b) Concept: IsoOrRtoSettlementsEnergyNetPurchasesPurchasedPower

CAISO - MRTU Purchases = -$60,620

CAISO - EIM Purchases = $3,439,790

(c) Concept: IsoOrRtoSettlementsEnergyNetPurchasesPurchasedPower

CAISO - MRTU Purchases = -$60,620
CAISO - EIM Purchases = $5,201,479

(d) Concept: IsoOrRtoSettlementsEnergyNetPurchasesPurchasedPower

CAISO - MRTU Purchases = -$60,620
CAISO - EIM Purchases = $5,858,385

(e) Concept: IsoOrRtoSettlementsEnergyNetSales

CAISO - MRTU Sales = -$12,111

CAISO - EIM Sales = $1,442,402

(f) Concept: IsoOrRtoSettlementsEnergyNetSales

CAISO - MRTU Sales = -$11,921
CAISO - EIM Sales = $3,483,281

(g) Concept: IsoOrRtoSettlementsEnergyNetSales

CAISO - MRTU Sales = $10,230
CAISO - EIM Sales = $5,623,640

(h) Concept: IsoOrRtoSettlementsEnergyNetSales

CAISO - MRTU Sales = $10,230
CAISO - EIM Sales = $8,244,975

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.
In columns for usage, report usage-related billing determinant and the unit of measure.

1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

| | | Amount Purchased for the Year | | | Amount Sold for the Year | | |
|---|---|---|---|---|---|---|---|
| | | Usage - Related Billing Determinant | | | Usage - Related Billing Determinant | | |
| Line No. | Type of Ancillary Service (a) | Number of Units (b) | Unit of Measure (c) | Dollar (d) | Number of Units (e) | Unit of Measure (f) | Dollars (g) |
| 1 | Scheduling, System Control and Dispatch | | | | | | |
| 2 | Reactive Supply and Voltage | | | | | | |
| 3 | Regulation and Frequency Response | | | | 95 | MW | 1,223,707 |
| 4 | Energy Imbalance | | | | | | |
| 5 | Operating Reserve - Spinning | | | | 1 | MW | 15,010 |
| 6 | Operating Reserve - Supplement | | | | 1 | MW | 13,828 |
| 7 | Other | 874 | MW | [(a)]10,944,214 | 874 | MW | [(b)]10,944,214 |
| 8 | Total (Lines 1 thru 7) | 874 | | 10,944,214 | 971 | | 12,196,759 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

FOOTNOTE DATA

| |
|---|
| (a) Concept: AncillaryServicesPurchasedAmount |
| Amounts reported are offsetting imputed amounts reflecting the self-provision of ancillary service for bundled retail native load customers under state jurisdiction. |
| (b) Concept: AncillaryServicesSoldAmount |
| Amounts reported are offsetting imputed amounts reflecting the self-provision 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: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## MONTHLY TRANSMISSION SYSTEM PEAK LOAD

1. Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Columns (c ) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

| Line No. | Month (a) | Monthly Peak MW - Total (b) | Day of Monthly Peak (c) | Hour of Monthly Peak (d) | Firm Network Service for Self (e) | Firm Network Service for Others (f) | Long-Term Firm Point-to-point Reservations (g) | Other Long-Term Firm Service (h) | Short-Term Firm Point-to-point Reservation (i) | Other Service (j) |
|---|---|---|---|---|---|---|---|---|---|---|
| | NAME OF SYSTEM: Avista Corporation | | | | | | | | | |
| 1 | January | 3,630 | 29 | 8 | 1,687 | 414 | 998 | 15 | 531 | 370 |
| 2 | February | 3,864 | 12 | 8 | 1,849 | 494 | 998 | 17 | 523 | 320 |
| 3 | March | 3,026 | 14 | 8 | 1,376 | 321 | 1,010 | 11 | 319 | 410 |
| 4 | Total for Quarter 1 | | | | 4,912 | 1,229 | 3,006 | 43 | 1,373 | 1,100 |
| 5 | April | 3,051 | 4 | 8 | 1,233 | 307 | 1,229 | 8 | 282 | 504 |
| 6 | May | 3,294 | 28 | 18 | 1,319 | 292 | 1,232 | 19 | 451 | 245 |
| 7 | June | 3,375 | 30 | 18 | 1,532 | 348 | 1,227 | 32 | 268 | 125 |
| 8 | Total for Quarter 2 | | | | 4,084 | 947 | 3,688 | 59 | 1,001 | 874 |
| 9 | July | 3,592 | 14 | 18 | 1,591 | 357 | 1,233 | 32 | 411 | 25 |
| 10 | August | 3,501 | 25 | 17 | 1,605 | 354 | 1,233 | 24 | 309 | 295 |
| 11 | September | 3,684 | 2 | 18 | 1,709 | 375 | 1,224 | 19 | 376 | 382 |
| 12 | Total for Quarter 3 | | | | 4,905 | 1,086 | 3,690 | 75 | 1,096 | 702 |
| 13 | October | 3,193 | 11 | 19 | 951 | 225 | 1,277 | 13 | 740 | 207 |
| 14 | November | 3,178 | 25 | 9 | 1,266 | 318 | 1,265 | 20 | 329 | 250 |
| 15 | December | 3,608 | 2 | 18 | 1,355 | 332 | 1,265 | 9 | 656 | 196 |
| 16 | Total for Quarter 4 | | | | 3,572 | 875 | 3,807 | 42 | 1,725 | 653 |
| 17 | Total | | | | 17,473 | 4,137 | 14,191 | 219 | 5,195 | 3,329 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 2026-04-17 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

| Line No. | Item (a) | MegaWatt Hours (b) | Line No. | Item (a) | MegaWatt Hours (b) |
|---|---|---|---|---|---|
| 1 | SOURCES OF ENERGY | | 21 | DISPOSITION OF ENERGY | |
| 2 | Generation (Excluding Station Use): | | 22 | Sales to Ultimate Consumers (Including Interdepartmental Sales) | 9,756,846 |
| 3 | Steam | 1,733,781 | 23 | Requirements Sales for Resale (See instruction 4, page 311.) | |
| 4 | Nuclear | | 24 | Non-Requirements Sales for Resale (See instruction 4, page 311.) | 4,554,075 |
| 5 | Hydro-Conventional | 3,194,653 | 25 | Energy Furnished Without Charge | |
| 6 | Hydro-Pumped Storage | | 26 | Energy Used by the Company (Electric Dept Only, Excluding Station Use) | 13,415 |
| 6.1 | Solar | | 27 | Total Energy Losses | 306,010 |
| 6.2 | Wind | | 27.1 | Total Energy Stored | |
| 6.3 | Other Renewable | | 28 | TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES | 14,630,346 |
| 7 | Other | 3,081,510 | | | |
| 8 | Less Energy for Pumping | | | | |
| 9 | Net Generation (Enter Total of lines 3 through 8) | 8,009,944 | | | |
| 10 | Purchases (other than for Energy Storage) | 6,619,942 | | | |
| 10.1 | Purchases for Energy Storage | 0 | | | |
| 11 | Power Exchanges: | | | | |
| 12 | Received | 460 | | | |
| 13 | Delivered | 0 | | | |
| 14 | Net Exchanges (Line 12 minus line 13) | 460 | | | |
| 15 | Transmission For Other (Wheeling) | | | | |
| 16 | Received | 3,527,542 | | | |
| 17 | Delivered | 3,527,542 | | | |
| 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) | 14,630,346 | | | |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

| Line No. | Month (a) | Total Monthly Energy (b) | Monthly Non-Requirement Sales for Resale & Associated Losses (c) | Monthly Peak - Megawatts (d) | Monthly Peak - Day of Month (e) | Monthly Peak - Hour (f) |
|---|---|---|---|---|---|---|
| | NAME OF SYSTEM: Avista Corporation | | | | | |
| 29 | January | 1,283,895 | 278,819 | 1,677 | 22 | 8 |
| 30 | February | 1,205,960 | 293,919 | 1,832 | 13 | 8 |
| 31 | March | 1,264,989 | 422,701 | 1,399 | 6 | 8 |
| 32 | April | 1,268,192 | 516,836 | 1,307 | 4 | 8 |
| 33 | May | 1,248,302 | 502,204 | 1,439 | 28 | 18 |
| 34 | June | 1,322,173 | 534,685 | 1,672 | 9 | 18 |
| 35 | July | 1,222,510 | 323,999 | 1,815 | 30 | 17 |
| 36 | August | 1,144,487 | 275,282 | 1,734 | 11 | 18 |
| 37 | September | 1,059,527 | 281,304 | 1,837 | 2 | 18 |
| 38 | October | 1,151,170 | 383,888 | 1,304 | 30 | 9 |
| 39 | November | 1,134,300 | 318,287 | 1,455 | 30 | 18 |
| 40 | December | 1,324,841 | 422,151 | 1,497 | 29 | 18 |
| 41 | Total | 14,630,346 | 4,554,075 | | | |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ 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 | 1985 | 2003 | 1983 | 1995 | 1978 |
| 5 | Total Installed Cap (Max Gen Name Plate Ratings-MW) | 25 | 233 | 287 | 58 | 167 | 62 |
| 6 | Net Peak Demand on Plant - MW (60 minutes) | 26 | 228 | 319 | 179 | 218 | 60 |
| 7 | Plant Hours Connected to Load | 6,368 | 13,760 | 7,696 | 6,525 | 6,746 | 11 |
| 8 | Net Continuous Plant Capability (Megawatts) | 25 | 222 | 322 | 53 | 166 | 65 |
| 9 | When Not Limited by Condenser Water | 0 | 222 | 322 | 53 | 0 | 0 |
| 10 | When Limited by Condenser Water | 0 | 222 | 322 | 53 | 0 | 0 |
| 11 | Average Number of Employees | 3 | 257 | 30 | 28 | 1 | 1 |
| 12 | Net Generation, Exclusive of Plant Use - kWh | 125,781,000 | 1,442,496,000 | 2,161,719,000 | 291,285,000 | 793,245,000 | 526,000 |
| 13 | Cost of Plant: Land and Land Rights | 144,733 | 1,289,395 | 0 | 2,779,633 | 621,682 | 138,753 |
| 14 | Structures and Improvements | 1,405,275 | 111,412,021 | 11,811,042 | 36,828,754 | 3,667,146 | 758,635 |
| 15 | Equipment Costs | 38,351,532 | 230,194,272 | 194,502,023 | 121,046,612 | 62,307,664 | 13,598,483 |
| 16 | Asset Retirement Costs | 0 | 16,926,371 | 351,682 | 323,787 | 0 | 0 |
| 17 | Total Cost (10-23) | 39,901,540 | 359,822,059 | 206,664,747 | 160,978,786 | 66,596,492 | 14,495,871 |
| 18 | Cost per KW of Installed Capacity (line 17/5) Including | 1,596.0616 | 1,544.3007 | 720.0862 | 2,775.4963 | 398.7814 | 233.8044 |
| 19 | Production Expenses: Oper, Supv, & Engr | 38,283 | 174,907 | 260,214 | 103,717 | 35,030 | 29,490 |
| 20 | Fuel | 3,170,244 | 32,308,150 | 44,752,244 | 10,429,770 | 24,198,904 | 22,621 |
| 21 | Coolants and Water (Nuclear Plants Only) | | | | | | |
| 22 | Steam Expenses | 0 | 3,523,846 | 0 | 684,628 | 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 | 477,158 | (8,938) | 4,465,523 | 949,381 | 347,121 | 10,207 |
| 26 | Misc Steam (or Nuclear) Power Expenses | 79,827 | 6,001,356 | 975,255 | 530,205 | 9,897 | 213,940 |
| 27 | Rents | 0 | 0 | 103,105 | 0 | 0 | 0 |
| 28 | Allowances | 0 | 0 | 0 | 0 | 0 | 0 |
| 29 | Maintenance Supervision and Engineering | 44,690 | 466,657 | 405,751 | 47,941 | 39,470 | 3,045 |
| 30 | Maintenance of Structures | 1,164 | 925,745 | 95,485 | 202,567 | 4,212 | 0 |
| 31 | Maintenance of Boiler (or reactor) Plant | 0 | 7,660,474 | 0 | 1,652,960 | 0 | 0 |
| 32 | Maintenance of Electric Plant | 435,902 | 2,412,089 | 3,193,636 | 490,863 | 389,365 | 9,206 |
| 33 | Maintenance of Misc Steam (or Nuclear) Plant | 130,937 | 1,333,974 | 122,498 | 517,233 | 44,310 | 28,753 |
| 34 | Total Production Expenses | 4,378,205 | 54,798,260 | 54,373,711 | 15,609,265 | 25,068,309 | 317,262 |
| 35 | Expenses per Net kWh | 0.0348 | 0.038 | 0.0252 | 0.0536 | 0.0316 | 0.6032 |

| 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 | 1,121,158 | 903,153 | 1,989 | 14,271,319 | 2,512 | 454,737 | 9,371,097 | 6,837 |
| 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 | 2.83 | 35.49 | 128.35 | 3.14 | 4.17 | 22.91 | 2.58 | 3.31 |
| 41 | Average Cost of Fuel per Unit Burned | 2.83 | 35.49 | 128.35 | 3.14 | 4.17 | 22.91 | 2.58 | 3.31 |
| 42 | Average Cost of Fuel Burned per Million BTU | 2.77 | 2.09 | 21.83 | 3.07 | 4.09 | 2.66 | 2.53 | 3.24 |
| 43 | Average Cost of Fuel Burned per kWh Net Gen | 0.03 | 0.02 | 0 | 0.02 | 0.05 | 0.04 | 0.03 | 0.04 |
| 44 | Average BTU per kWh Net Generation | 9,092 | 10,633 | 0 | 6,734 | 0 | 13,436 | 12,050 | 13,258 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

**Hydroelectric Generating Plant Statistics**

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

| Line No. | Item (a) | FERC Licensed Project No. 2058 Plant Name: Cabinet Gorge | FERC Licensed Project No. 2545 Plant Name: Little Falls | FERC Licensed Project No. 2545 Plant Name: Long Lake | 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 | FERC Licensed Project No. 2545 Plant Name: Upper Falls |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Kind of Plant (Run-of-River or Storage) | Storage | Run-of-River | Storage | Run-of-River | Run-of-River | Storage | Storage | Run-of-River |
| 2 | Plant Construction type (Conventional or Outdoor) | Outdoor | Conventional | Conventional | Conventional | Conventional | Outdoor | Conventional | Conventional |
| 3 | Year Originally Constructed | 1952 | 1910 | 1915 | 1890 | 1908 | 1959 | 1906 | 1922 |
| 4 | Year Last Unit was Installed | 1953 | 1911 | 1924 | 1992 | 1994 | 1977 | 1980 | 1922 |
| 5 | Total installed cap (Gen name plate Rating in MW) | 265.2 | 43.2 | 70 | 14.8 | 37.6 | 487.8 | 14.5 | 10 |
| 6 | Net Peak Demand on Plant-Megawatts (60 minutes) | 262 | 47 | 100 | 223 | 77 | 516 | 42 | 11 |
| 7 | Plant Hours Connect to Load | 8,742 | 7,181 | 7,208 | 8,575 | 8,756 | 6,757 | 8,665 | 8,760 |
| 8 | **Net Plant Capability (in megawatts)** | | | | | | | | |
| 9 | (a) Under Most Favorable Oper Conditions | 255 | 43 | 90 | 15 | 38 | 581 | 18 | 10 |
| 10 | (b) Under the Most Adverse Oper Conditions | 295 | 43 | 90 | 15 | 38 | 623 | 18 | 10 |
| 11 | Average Number of Employees | 1 | 1 | 1 | 4 | 5 | 10 | 5 | 4 |
| 12 | Net Generation, Exclusive of Plant Use - kWh | 886,290,000 | 188,764,000 | 435,363,000 | 87,467,000 | 132,210,000 | 1,362,126,000 | 60,420,000 | 42,013,000 |
| 13 | **Cost of Plant** | | | | | | | | |
| 14 | Land and Land Rights | 18,643,682 | 4,325,371 | 2,421,233 | 51,600 | 33,429 | 37,481,948 | 4,161,522 | 1,081,854 |
| 15 | Structures and Improvements | 29,767,992 | 6,217,736 | 11,514,182 | 12,281,570 | 24,929,081 | 25,647,910 | 8,334,317 | 5,128,433 |
| 16 | Reservoirs, Dams, and Waterways | 114,799,167 | 6,407,917 | 39,136,697 | 10,010,069 | 30,933,636 | 45,335,869 | 26,063,988 | 10,108,507 |
| 17 | Equipment Costs | 95,354,423 | 54,594,545 | 17,728,958 | 14,659,584 | 68,604,748 | 116,900,975 | 6,964,358 | 8,246,682 |
| 18 | Roads, Railroads, and Bridges | 1,897,603 | 0 | 0 | 50,448 | 594,870 | 305,777 | 577,944 | 508,242 |
| 19 | Asset Retirement Costs | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 20 | Total Cost (10-23) | 260,462,867 | 71,545,569 | 70,801,070 | 37,053,271 | 125,095,764 | 225,672,479 | 46,102,129 | 25,073,718 |
| 21 | Cost per KW of Installed Capacity (line 20 / 5) | 982.1375 | 1,656.1474 | 1,011.4439 | 2,503.5994 | 3,327.015 | 462.6332 | 3,179.4572 | 2,507.3718 |
| 22 | **Production Expenses** | | | | | | | | |
| 23 | Operation Supervision and Engineering | 191,885 | 3,473 | 74,227 | 20,214 | 23,786 | 92,432 | 27,570 | 18,246 |
| 24 | Water for Power | 0 | 0 | 0 | 0 | 0 | 0 | 2,759 | 0 |
| 25 | Hydraulic Expenses | 0 | 9,510 | 7,281 | 588 | 969 | 80,307 | 2,876 | 590 |
| 26 | Electric Expenses | 1,142,449 | 808,194 | 920,944 | 698,805 | 818,883 | 1,153,008 | 906,660 | 698,502 |
| 27 | Misc Hydraulic Power Generation Expenses | 135,616 | 25,519 | 201,515 | 22,973 | 92,940 | 213,159 | 43,274 | 71,348 |
| 28 | Rents | 0 | 1,319,386 | 0 | 0 | 0 | 0 | 0 | 0 |
| 29 | Maintenance Supervision and Engineering | 123,449 | 403 | 2,907 | 39,271 | 20,583 | 62,854 | 16,414 | 2,343 |
| 30 | Maintenance of Structures | 260,669 | 57,986 | 215,623 | 40,907 | 12,564 | 15,420 | 50,216 | 18,135 |
| 31 | Maintenance of Reservoirs, Dams, and Waterways | 180,204 | 89,373 | 85,596 | 199,088 | 24,211 | 9,209 | 82,710 | 7,519 |
| 32 | Maintenance of Electric Plant | 612,464 | 318,906 | 353,905 | 69,597 | 188,141 | 628,342 | 138,168 | 81,965 |
| 33 | Maintenance of Misc Hydraulic Plant | 65,058 | 8,935 | 71,136 | 3,738 | 41,356 | 68,950 | 954 | 2,616 |
| 34 | Total Production Expenses (total 23 thru 33) | 2,711,794 | 2,641,685 | 1,933,134 | 1,095,181 | 1,223,433 | 2,323,681 | 1,271,601 | 901,264 |
| 35 | Expenses per net kWh | 0.0031 | 0.014 | 0.0044 | 0.0125 | 0.0093 | 0.0017 | 0.021 | 0.0215 |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants, pumped storage plants, and renewable plants of less than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, renewable, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
4. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

| Line No. | Name of Plant (a) | Year Orig. Const. (b) | Installed Capacity Name Plate Rating (MW) (c) | Net Peak Demand MW (60 min) (d) | Net Generation Excluding Plant Use (e) | Cost of Plant (f) | Plant Cost (Incl Asset Retire. Costs) Per MW (g) | Operation Exc'l. Fuel (h) | Production Expenses: Fuel Production Expenses (i) | Production Expenses: Maintenance Production Expenses (j) | Kind of Fuel (k) | Fuel Costs (in cents (per Million Btu) (l) | Generation Type (m) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Kettle Falls CT | 2002 | 7.2 | 8 | 239,000 | 9,571,547 | 1,323,903 | 91,825 | 117,772 | 15,231 | Natural Gas | 4,210.9 | Gas Turbine |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in gro totals only for each voltage. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than o type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from remainder of the line.
5. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the p miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.
6. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).
7. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for ye any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining th arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
8. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

| Line No. | DESIGNATION | | VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase) | | Type of Supporting Structure | LENGTH (Pole miles) - (In the case of underground lines report circuit miles) | | Number of Circuits | Size of Conductor and Material | COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way) | | | EXPENSES, EXCEPT DEPRECIATION A TAXES | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | From | To | Operating | Designated | | On Structure of Line Designated | On Structures of Another Line | | | Land | Construction Costs | Total Costs | Operation Expenses | Maintenance Expenses | Rents | T Exp |
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) | |
| 1 | Group Sum - 60kV | | 60 | 60 | | 1 | | | | 136,038 | 636,193 | 772,231 | | | | |
| 2 | Group Sum - 115kV | | 115 | 115 | | 1,565 | | | | 13,124,253 | 400,190,702 | 413,314,955 | 1,105,774 | 4,258,790 | | 5,3 |
| 3 | Beacon Sub #4 | BPA Bell Sub | 230 | 230 | Steel Pole | 1 | | 1 | 1272 ACSS | | | 0 | | | | |
| 4 | Beacon Sub #4 | BPA Bell Sub | 230 | 230 | H Type | 5 | | 1 | 1272 ACSS | 17,912 | 1,424,560 | 1,442,472 | 0 | 11,987 | | |
| 5 | Beacon Sub #5 | BPA Bell Sub | 230 | 230 | Steel Tower | 3 | | 1 | 1272 ACSS | | | 0 | | | | |
| 6 | Beacon Sub #5 | BPA Bell Sub | 230 | 230 | H Type | 3 | | 1 | 1272 ACSS | 30,323 | 3,271,116 | 3,301,439 | 0 | 0 | | |
| 7 | Beacon | Cabinet Gorge Plant | 230 | 230 | Steel Tower | 1 | | 1 | 1590 ACSS | | | 0 | | | | |
| 8 | Beacon | Cabinet Gorge Plant | 230 | 230 | Steel Pole | 41 | | 2 | 1590 ACSS | | | 0 | | | | |
| 9 | Beacon | Cabinet Gorge Plant | 230 | 230 | H Type | 52 | | 1 | 1590 ACSR | 1,156,296 | 41,768,911 | 42,925,207 | 0 | 158,796 | | 1 |
| 10 | Beacon Sub | Lolo Sub | 230 | 230 | Steel Tower | 1 | | 1 | 1590 ACSS | | | 0 | | | | |
| 11 | Beacon Sub | Lolo Sub | 230 | 230 | Steel Pole | 12 | | 2 | 1590 ACSS | | | 0 | | | | |
| 12 | Beacon Sub | Lolo Sub | 230 | 230 | H Type | 88 | | 1 | 1272 AAC | | | 0 | | | | |
| 13 | Beacon Sub | Lolo Sub | 230 | 230 | H Type | 8 | | 1 | 1272 ACSS | 196,836 | 34,883,953 | 35,080,789 | 0 | 29,278 | | |
| 14 | Benewah | Shawnee | 230 | 230 | Steel Pole | 1 | | 1 | 1622 ACSS | | | 0 | | | | |
| 15 | Benewah | Shawnee | 230 | 230 | Steel Pole | 59 | | 1 | 1590 ACSS | 570,207 | 47,971,774 | 48,541,981 | 0 | 5,405 | | |
| 16 | Noxon Plant | Pine Creek Sub | 230 | 230 | Steel Pole | 29 | | 1 | 1272 ACSR | | | 0 | | | | |
| 17 | Noxon Plant | Pine Creek Sub | 230 | 230 | H Type | 1 | | 1 | 1590 ACSS | | | 0 | | | | |
| 18 | Noxon Plant | Pine Creek Sub | 230 | 230 | H Type | 14 | | 1 | 954 AAC | 1,099,064 | 20,492,311 | 21,591,375 | 7,359 | 835,413 | | 8 |
| 19 | Cabinet Gorge Plant | Noxon | 230 | 230 | H Type | 2 | | 1 | 795 ACSR | | | 0 | | | | |
| 20 | Cabinet Gorge Plant | Noxon | 230 | 230 | H Type | 17 | | 1 | 954 AAC | 184,528 | 2,430,435 | 2,614,963 | 32,638 | 86,857 | | 1 |
| 21 | Benewah Sw. Station | Pine Creek Sub | 230 | 230 | H Type | 43 | | 1 | 954 AAC | 399,821 | 5,556,919 | 5,956,740 | 0 | 195,146 | | 1 |
| 22 | Divide Creek | Lolo Sub | 230 | 230 | H Type | 18 | | 1 | 1590 ACSR | | | 0 | | | | |
| 23 | Divide Creek | Lolo Sub | 230 | 230 | H Type | 25 | | 1 | 1272 AAC | 174,552 | 29,043,660 | 29,218,212 | 2,012 | 54,878 | | |
| 24 | North Lewiston | Walla Walla | 230 | 230 | H Type | 40 | | 1 | 1272 AAC | | | 0 | | | | |
| 25 | North Lewiston | Walla Walla | 230 | 230 | H Type | 4 | | 1 | 1272 ACSR | | | 0 | | | | |
| 26 | North Lewiston | Walla Walla | 230 | 230 | Steel Pole | 4 | | 1 | 1272 ACSR | 623,984 | 6,807,349 | 7,431,333 | 22,555 | 0 | | |
| 27 | North Lewiston | Shawnee | 230 | 230 | Steel Pole | 7 | | 1 | 1272 ACSR | | | 0 | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 28 | North Lewiston | Shawnee | 230 | 230 | H Type | 27 | | 1 | 1272 ACSR | 872,150 | 9,996,899 | 10,869,049 | 0 | 0 | | |
| 29 | Saddle Mtn-Walla Walla | Wanapum | 230 | 230 | Steel Tower | 2 | | 1 | 1590 ACSS | | | 0 | | | | |
| 30 | Saddle Mtn-Walla Walla | Wanapum | 230 | 230 | H Type | 79 | | 1 | 1272 AAC | 316,135 | 14,141,471 | 14,457,606 | 0 | 19,431 | | |
| 31 | BPA (Libby) | Noxon Plant | 230 | 230 | Steel Pole | 1 | | 1 | 1272 ACSR | | | 0 | | | | |
| 32 | BPA/Hot Springs #1 | Noxon Plant | 230 | 230 | Steel Pole | 1 | | 1 | 1272 ACSR | 0 | 18,772 | 18,772 | 0 | 0 | | |
| 33 | BPA/Hot Springs #2 | Noxon Plant | 230 | 230 | Steel Pole | 2 | | 1 | 1272 ACSR | | | 0 | | | | |
| 34 | BPA/Hot Springs #2 | Noxon Plant | 230 | 230 | H Type | 1 | | 1 | 1622 ACSS | | | 0 | | | | |
| 35 | BPA/Hot Springs #2 | Noxon Plant | 230 | 230 | H Type | 66 | | 1 | 1272 AAC | 3,604,778 | 11,256,609 | 14,861,387 | 1,936 | 182,841 | | 1 |
| 36 | Coulee | West Side Sub | 230 | 230 | Steel Pole | 2 | | 2 | 1272 ACSR | 8,482 | 0 | 8,482 | 0 | 0 | | |
| 37 | BPA Line | West Side Sub | 230 | 230 | Steel Pole | 2 | | 2 | 1272 ACSR | 36,461 | 1,488,214 | 1,524,675 | 0 | 0 | | |
| 38 | Hatwai | N. Lewiston Sub | 230 | 230 | H Type | 7 | | 1 | 1590 ACSR | 155,244 | 2,222,042 | 2,377,286 | 0 | 0 | | |
| 39 | Divide Creek | Imnaha | 230 | 230 | H Type | 2 | | 1 | 1622 ACSS | | | 0 | | | | |
| 40 | Divide Creek | Imnaha | 230 | 230 | H Type | 2 | | 1 | 1590 ACSR | | | 0 | | | | |
| 41 | Divide Creek | Imnaha | 230 | 230 | H Type | 16 | | 1 | 1272 AAC | 205,262 | 1,312,224 | 1,517,486 | 0 | 106 | | |
| 42 | Colstrip Plant | Broadview | 500 | 500 | | 0 | | | | 595,789 | 40,186,844 | 40,782,633 | 113,895 | 143,428 | 91,761 | 3 |
| 36 | TOTAL | | | | | 2,255 | 0 | 43 | | 23,508,115 | 675,100,958 | 698,609,073 | 1,286,169 | 5,982,356 | 91,761 | 7,3 |

| Name of Respondent:<br>Avista Corporation | This report is:<br>(1) ☑ An Original<br>(2) ☐ A Resubmission | Date of Report:<br>04/17/2026 | Year/Period of Report<br>End of: 2025/ Q4 |
|---|---|---|---|

**TRANSMISSION LINES ADDED DURING YEAR**

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

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

| Name of Respondent:<br>Avista Corporation | This report is:<br>(1) ☑ An Original<br>(2) ☐ A Resubmission | Date of Report:<br>04/17/2026 | Year/Period of Report<br>End of: 2025/ Q4 |
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## SUBSTATIONS

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

| 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) | 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 | Airway Heights (WA) | Distribution | Unattended | 115 | 13.8 | | 26.88 | 2 | | Frcd Oil & Air Fan & Caps | 39 | 44.8 |
| 2 | Arden (WA) | Distribution | Unattended | 115 | 13.8 | | 8.4 | 1 | | Frcd Air Fan | 1 | 10.5 |
| 3 | Barker Road (WA) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Two Stage Fan | 1 | 22.4 |
| 4 | Beacon (Trans. & Dist.) (WA) | Transmission | Unattended | 230 | 115 | 13.8 | 600.32 | 4 | | Two Stage Fan | 2 | 627.2 |
| 5 | Boulder (Trans. & Dist.) (WA) | Transmission | Unattended | 230 | 115 | 13.8 | 356.16 | 3 | | Two Stage Fan | 3 | 593.6 |
| 6 | Chester (WA) | Distribution | Unattended | 115 | 13.8 | | 25.44 | 2 | | Frcd Oil & Air Fan | 2 | 42.4 |
| 7 | Chewelah 115Kv (WA) | Distribution | Unattended | 115 | 13.2 | | 13.44 | 1 | | Two Stage Fan | 1 | 22.4 |
| 8 | Colbert (WA) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Frcd Oil & Air Fan & Caps | 16 | 22.4 |
| 9 | College & Walnut (WA) | Distribution | Unattended | 115 | 13.8 | | 40.32 | 2 | | Two Stage Fan | 2 | 67.2 |
| 10 | Colville 115 Kv (WA) | Distribution | Unattended | 115 | 13.8 | | 35.2 | 3 | | Frcd Oil & Air Fan | 3 | 55.3 |
| 11 | Critchfield (WA) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Two Stage Fan | 1 | 22.4 |
| 12 | Davenport (WA) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Frcd Oil & Air Fan | 1 | 22.4 |
| 13 | Deer Park (WA) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Two Stage Fan | 1 | 22.4 |
| 14 | Downriver (WA) | Distribution | Unattended | 115 | 13.8 | | 26.88 | 2 | | Frcd Oil & Air & Two Stage Fan | 2 | 44.8 |
| 15 | Dry Creek (WA) | Transmission | Unattended | 230 | 115 | 13.8 | 168 | 1 | | Two Stage Fan & Caps | 224 | 280 |
| 16 | Dry Gulch (WA) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Frcd Oil & Air Fan | 1 | 22.4 |
| 17 | East Colfax (WA) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Frcd Oil & Air Fan | 1 | 22.4 |
| 18 | East Farms (WA) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Two Stage Fan | 1 | 22.4 |
| 19 | Flint Rd (WA) | Distribution | Unattended | 115 | 13.8 | | 40.32 | 2 | | Two Stage Fan | 2 | 67.2 |
| 20 | Ford (WA) | Distribution | Unattended | 115 | 13.8 | | 8.4 | 1 | | Frcd Air Fan | 1 | 10.5 |
| 21 | Francis and Cedar (WA) | Distribution | Unattended | 115 | 13.8 | | 40.32 | 2 | | Two Stage Fan | 2 | 67.2 |
| 22 | Gifford (WA) | Distribution | Unattended | 115 | 34 | | 17.64 | 2 | | One Stage Fan | 1 | 18.69 |
| 23 | Glenrose (WA) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Frcd Oil & Air Fan | 1 | 22.4 |
| 24 | Greenacres (WA) | Distribution | Unattended | 115 | 13.8 | | 40.32 | 2 | | Two Stage Fan | 2 | 67.2 |
| 25 | Greenwood (WA) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Two Stage Fan | 1 | 22.4 |
| 26 | Hallett & White (WA) | Distribution | Unattended | 115 | 13.8 | | 36 | 2 | | Two Stage Fan | 2 | 60 |
| 27 | Indian Trail (WA) | Distribution | Unattended | 115 | 13.8 | | 26.8 | 2 | | Two Stage Fan | 2 | 44.8 |
| 28 | Kettle Falls (WA) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Frcd Oil & Air Fan | 1 | 22.4 |
| 29 | Lee & Reynolds (WA) | Distribution | Unattended | 115 | 13.8 | | 40.32 | 2 | | Two Stage Fan | 2 | 67.2 |
| 30 | Liberty Lake (WA) | Distribution | Unattended | 115 | 13.8 | | 26.88 | 2 | | Two Stage Fan | 2 | 44.8 |
| 31 | Lind (WA) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Two Stage Fan | 1 | 22.4 |
| 32 | Little Falls 115/34 Kv (WA) | Distribution | Unattended | 115 | 34 | | 13.44 | 1 | | | | |
| 33 | Lyons & Standard (WA) | Distribution | Unattended | 115 | 13.8 | | 40.32 | 2 | | Two Stage Fan | 2 | 67.2 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 34 | Mead (WA) | Distribution | Unattended | 115 | 13.8 | | 20.16 | 1 | | Two Stage Fan | 1 | 33.6 |
| 35 | Metro (WA) | Distribution | Unattended | 115 | 13.8 | | 26.88 | 2 | | Two Stage Fan | 2 | 44.8 |
| 36 | Milan (WA) | Distribution | Unattended | 115 | 13.8 | | 26.88 | 2 | | Frcd Oil & Air Fan | 2 | 44.8 |
| 37 | Millwood (WA) | Distribution | Unattended | 115 | 13.8 | | 49.2 | 2 | | Two Stage Fan | 2 | 72.8 |
| 38 | Ninth & Central (WA) | Distribution | Unattended | 115 | 13.8 | | 40.32 | 2 | | Two Stage Fan | 2 | 67.2 |
| 39 | Northeast (WA) | Distribution | Unattended | 115 | 13.8 | | 26.88 | 2 | | Two Stage Fan | 2 | 44.8 |
| 40 | Northwest (WA) | Distribution | Unattended | 115 | 13.8 | | 26.88 | 2 | | Two Stage Fan | 2 | 44.8 |
| 41 | Opportunity (WA) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Two Stage Fan | 1 | 22.4 |
| 42 | Othello (WA) | Distribution | Unattended | 115 | 13.8 | | 40.32 | 2 | | Two Stage Fan | 2 | 67.2 |
| 43 | Post Street (WA) | Distribution | Unattended | 115 | 13.8 | | 67.2 | 2 | | Frcd Oil | 2 | 67.2 |
| 44 | Pound Lane (WA) | Distribution | Unattended | 115 | 13.8 | | 26.88 | 2 | | Two Stage Fan | 2 | 44.8 |
| 45 | Ritzville (WA) | Distribution | Unattended | 115 | 13.8 | | 8.4 | 1 | | Frcd Air Fan | 1 | 10.5 |
| 46 | Rosalia (WA) | Distribution | Unattended | 115 | 13.8 | | 8.4 | 1 | | Frcd Air Fan | 1 | 10.5 |
| 47 | Ross Park (WA) | Distribution | Unattended | 115 | 13.8 | | 37 | 2 | | Two Stage Fan | 2 | 61.6 |
| 48 | Roxboro (WA) | Distribution | Unattended | 115 | 24 | | 26.88 | 2 | | Two Stage Fan | 2 | 44.8 |
| 49 | Saddle Mountain (WA) | Transmission | Unattended | 230 | 115 | 13.8 | 168 | 1 | | Two Stage Fan | 1 | 280 |
| 50 | Shawnee (WA) | Transmission | Unattended | 230 | 115 | 13.8 | 168 | 1 | | Two Stage Fan | 1 | 280 |
| 51 | Silver Lake (WA) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Two Stage Fan | 1 | 22.4 |
| 52 | Southeast (WA) | Distribution | Unattended | 115 | 13.8 | | 40.32 | 2 | | Two Stage Fan | 2 | 67.2 |
| 53 | South Othello (WA) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Two Stage Fan | 1 | 22.4 |
| 54 | South Pullman (WA) | Distribution | Unattended | 115 | 13.8 | | 33.6 | 2 | | Two Stage Fan | 2 | 56 |
| 55 | Spirit (WA) | Distribution | Unattended | 115 | 13.8 | | 8.4 | 1 | | Frcd Air Fan | 1 | 10.5 |
| 56 | Spokane Industrial Park (WA) | Distribution | Unattended | 115 | 13.8 | | 30.13 | 3 | | Two Stg, Frcd Oil Fan & Caps | 15 | 47.09 |
| 57 | Sunset (WA) | Distribution | Unattended | 115 | 13.8 | | 40.32 | 2 | | Two Stage Fan & Caps | 50 | 67.2 |
| 58 | Tekoa (WA) | Distribution | Unattended | 115 | 13.8 | | 8.4 | 1 | | Frcd Air Fan | 1 | 10.5 |
| 59 | Terre View (WA) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Two Stage Fan | 1 | 22.4 |
| 60 | Third & Hatch (WA) | Distribution | Unattended | 115 | 13.8 | | 60.48 | 3 | | Two Stage Fan & Caps | 103 | 100.8 |
| 61 | Turner (WA) | Distribution | Unattended | 115 | 13.8 | | 40.32 | 2 | | Two Stage Fan | 2 | 67.2 |
| 62 | Valley (WA) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Two Stage Fan | 1 | 22.4 |
| 63 | Waikiki (WA) | Distribution | Unattended | 115 | 13.8 | | 26.88 | 2 | | Two Stage Fan | 2 | 44.8 |
| 64 | Wilbur (WA) | Distribution | Unattended | 115 | 13.8 | | 8.4 | 1 | | Frcd Air Fan | 1 | 10.5 |
| 65 | West Side (WA) | Transmission | Unattended | 230 | 115 | 13.8 | 336 | 2 | | Two Stage Fan | 2 | 560 |
| 66 | Other: 19 Subs. less than 10MVA (WA) | Distribution | Unattended | | | | 109.1 | 19 | | | | |
| 67 | Appleway (ID) | Distribution | Unattended | 115 | 13.8 | | 40.32 | 2 | | Two Stage Fan | 2 | 67.2 |
| 68 | Avondale (ID) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Two Stage Fan | 1 | 22.4 |
| 69 | Benewah (ID) | Transmission | Unattended | 230 | 115 | 13.8 | 168 | 1 | | Two Stage Fan & Caps | 224 | 280 |
| 70 | Big Creek (ID) | Distribution | Unattended | 115 | 13.8 | | 17.5 | 2 | | Portable Fan | 2 | 21.9 |
| 71 | Blue Creek (ID) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Two Stage Fan | 1 | 22.4 |
| 72 | Bunker Hill Limited (ID) | Distribution | Unattended | 115 | 13.8 | | 12 | 1 | | Frcd Air Fan | 1 | 16 |
| 73 | Cabinet Gorge (Switchyard) (ID) | Transmission | Unattended | 230 | 115 | 13.8 | 84 | 1 | | Two Stage Fan | 1 | 140 |
| 74 | Clark Fork (ID) | Distribution | Unattended | 115 | 21.8 | | 10 | 1 | | Frcd Air Fan | 1 | 12.5 |
| 75 | Coeur d' Alene 15th Ave. (ID) | Distribution | Unattended | 115 | 13.8 | | 40.32 | 2 | | Two Stage Fan | 2 | 67.2 |
| 76 | Cottonwood (ID) | Distribution | Unattended | 115 | 24.9 | | 13.44 | 1 | | Two Stage Fan | 1 | 22.4 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 77 | Craigmont (ID) | Distribution | Unattended | 115 | 13.8 | | 8.4 | 1 | | Frcd Air Fan | 1 | 10.5 |
| 78 | Dalton (ID) | Distribution | Unattended | 115 | 13.8 | | 40.32 | 2 | | Two Stage Fan | 2 | 67.2 |
| 79 | Deary (ID) | Distribution | Unattended | 115 | 24.9 | | 8.4 | 1 | | Frcd Air Fan | 1 | 10.5 |
| 80 | Grangeville (ID) | Distribution | Unattended | 115 | 13.8 | | 25.94 | 4 | | Frcd Oil & Air & Pt Fan & Caps | 17 | 36.78 |
| 81 | Holbrook (ID) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Two Stage Fan | 1 | 22.4 |
| 82 | Huetter (ID) | Distribution | Unattended | 115 | 13.8 | | 33.6 | 2 | | Two Stage Fan | 2 | 56 |
| 83 | Idaho Road (ID) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Two Stage Fan | 1 | 22.4 |
| 84 | Juliaetta (ID) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Frcd Oil & Air Fan | 1 | 22.4 |
| 85 | Kamiah (ID) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Two Stage Fan | 1 | 22.4 |
| 86 | Kooskia (ID) | Distribution | Unattended | 115 | 13.8 | | 15 | 3 | | Frcd Air Fan | 3 | 20 |
| 87 | Lewiston Mill Rd (ID) | Distribution | Unattended | 115 | 13.2 | | 20.16 | 1 | | Two Stage Fan | 1 | 33.6 |
| 88 | Lolo (Trans. & Dist.) (ID) | Transmission | Unattended | 230 | 115 | 13.8 | 349.44 | 3 | | Frcd Oil & Air Fan & Two Stage Fan | 3 | 582.4 |
| 89 | Lucky Friday (ID) | Distribution | Unattended | 115 | 13.8 | | 20.16 | 1 | | Two Stage Fan | 1 | 33.6 |
| 90 | Moscow (ID) | Distribution | Unattended | 115 | 13.8 | | 26.88 | 2 | | Frcd Oil & Air & Two Stage | 2 | 44.8 |
| 91 | Moscow 230 kV (Trans. & Dist.) (ID) | Transmission | Unattended | 230 | 115 | 13.8 | 181.44 | 2 | | Two Stage Fan & Caps | 76 | 302.4 |
| 92 | North Lewiston 230kV (Trans. & Dist.) (ID) | Transmission | Unattended | 230 | 115 | | 176.4 | 2 | | Frcd Air Fan & Caps & Two Stage Fan | 50 | 290.5 |
| 93 | North Moscow (ID) | Distribution | Unattended | 115 | 13.8 | | 12 | 1 | | Two Stage Fan | 1 | 20 |
| 94 | Oden (ID) | Distribution | Unattended | 115 | 21.8 | | 10 | 1 | | Frcd Air Fan | 1 | 12.5 |
| 95 | Oldtown (ID) | Distribution | Unattended | 115 | 21.8 | | 18.4 | 2 | | Frcd Air Fan | 2 | 23 |
| 96 | Orofino (ID) | Distribution | Unattended | 115 | 24 | | 21.84 | 2 | | Frcd Oil & Air Fan | 1 | 32.9 |
| 97 | Osburn (ID) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Portable Fan | 1 | 16.8 |
| 98 | Pine Creek (Trans. & Dist.) (ID) | Transmission | Unattended | 230 | 115 | 13.8 | 237.44 | 3 | | Two Stage Fan & Caps | 47 | 302.4 |
| 99 | Pleasant View (ID) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Two Stage Fan | 1 | 22.4 |
| 100 | Plummer (ID) | Distribution | Unattended | 115 | 13.8 | | 13.44 | 1 | | Two Stage Fan | 1 | 22.4 |
| 101 | Poleline (ID) | Distribution | Unattended | 115 | 13.8 | | 40.32 | 2 | | Two Stage Fan | 2 | 67.2 |
| 102 | Post Falls (ID) | Distribution | Unattended | 115 | 13.8 | | 20.16 | 1 | | Two Stage Fan | 1 | 33.6 |
| 103 | Potlatch (ID) | Distribution | Unattended | 115 | 24.9 | | 15.9 | 2 | | Portable Fan | 2 | 19.9 |
| 104 | Prairie (ID) | Distribution | Unattended | 115 | 13.8 | | 12 | 1 | | Frcd Oil & Air Fan | 1 | 20 |
| 105 | Priest River (ID) | Distribution | Unattended | 115 | 20.8 | | 10 | 1 | | Frcd Air Fan | 1 | 12.5 |
| 106 | Rathdrum (Trans. & Dist.) (ID) | Transmission | Unattended | 230 | 115 | 13.8 | 530.88 | 4 | | Frcd Oil & Air Fan & Caps | 39 | 548.8 |
| 107 | Sagle (ID) | Distribution | Unattended | 115 | 21.8 | | 13.44 | 1 | | Two Stage Fan | 1 | 22.4 |
| 108 | Sandpoint (ID) | Distribution | Unattended | 115 | 20.8 | | 32 | 3 | | Frcd Air Fan | 3 | 47.4 |
| 109 | South Lewiston (ID) | Distribution | Unattended | 115 | 13.8 | | 28.44 | 4 | | Portable Fan, Frcd Oil & Air | 4 | 41.15 |
| 110 | Spirit Lake (ID) | Distribution | Unattended | 115 | 13.8 | | 8.4 | 1 | | Frcd Air Fan | 1 | 10.5 |
| 111 | Sweetwater (ID) | Distribution | Unattended | 115 | 24.9 | | 13.44 | 1 | | Frcd Oil & Air Fan | 1 | 22.4 |
| 112 | St. Maries (ID) | Distribution | Unattended | 115 | 23.9 | | 26.88 | 2 | | Two Stage Fan | 2 | 44.8 |
| 113 | Tenth & Stewart (ID) | Distribution | Unattended | 115 | 13.8 | | 33.6 | 2 | | Frcd Oil & Air & Two Stage | 2 | 56 |
| 114 | Wallace (ID) | Distribution | Unattended | 115 | 13.8 | | 8.4 | 1 | | Frcd Air Fan | 1 | 10.5 |
| 115 | Weippe (ID) | Distribution | Unattended | 115 | 13.8 | | 8.4 | 1 | | Frcd Air Fan | 1 | 10.5 |
| 116 | Other: 8 Subs less than 10 MVA (ID ) | Distribution | Unattended | | | | 43.3 | 8 | | | | |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 117 | Other: 1 Sub less than 10 MVA (MT ) | Distribution | Unattended | | | | 5.6 | 1 | | | | | |
| 118 | Boulder Park (WA Gen. Plant) | Transmission | Attended | 115 | 13.8 | | 40.3 | 1 | | Two Stage Fan | 1 | 67.2 |
| 119 | Kettle Falls (WA Gen. Plant) | Transmission | Attended | 115 | 13.8 | | 49.6 | 1 | 1 | Two Stage Fan | 1 | 62 |
| 120 | Long Lake (WA Gen. Plant) | Transmission | Attended | 115 | 4 | | 80.6 | 4 | | | 4 | 89.6 |
| 121 | Nine Mile (WA Gen. Plant) | Transmission | Attended | 115 | 13.8 | | 42 | 2 | | Two Stage Fan | 1 | 64 |
| 122 | Little Falls (WA Gen. Plant) | Transmission | Attended | 115 | 4 | | 26.88 | 2 | | Frcd Oil & Air Fan | 2 | 44.8 |
| 123 | Northeast (WA Gen. Plant) | Transmission | Attended | 115 | 13.8 | | 40.3 | 1 | | Two Stage Fan | 1 | 67.2 |
| 124 | Post Street (WA Gen. Plant) | Transmission | Attended | 13.8 | 4 | | 37.4 | 2 | | | | |
| 125 | Cabinet Gorge (HED) (ID Gen. Plant) | Transmission | Attended | 230 | 13.2 | | 336 | 6 | 1 | | | |
| 126 | Post Falls (ID Gen. Plant) | Transmission | Attended | 115 | 2.3 | | 12 | 1 | | Frcd Air & Oil & Air Fan | 1 | 16 |
| 127 | Rathdrum (ID Gen. Plant) | Transmission | Attended | 115 | 13.8 | | 127.8 | 2 | 1 | Two Stage Fan | 2 | 212.8 |
| 128 | Noxon (MT Gen. Plant) | Transmission | Attended | 230 | 13.8 | | 487.2 | 9 | 1 | Two Stage Fan | 6 | 711 |
| 129 | Coyote Springs II (OR Gen. Plant) | Transmission | Attended | 500 | 13.8 | 18 | 270 | 3 | 1 | Two Stage Fan | 3 | 450 |
| 131 | Distribution Substations | | | 11,615 | 1,553.9 | 0 | 2,410.35 | 186 | | | 380 | 3,547.61 |
| 132 | Distribution Substations Unattended | | | 11,615 | 1,553.9 | 0 | 2,410.35 | 186 | | | 380 | 3,547.61 |
| 133 | Transmission Substations | | | 4,883.8 | 1,619.1 | 183.6 | 5,074.16 | 62 | 5 | | 695 | 6,851.9 |
| 134 | Transmission Substations Attended | | | 1,893.8 | 124.1 | 18 | 1,550.08 | 34 | 5 | | 22 | 1,784.6 |
| 135 | Transmission Substations Unattended | | | 2,990 | 1,495 | 165.6 | 3,524.08 | 28 | 0 | | 673 | 5,067.3 |
| 136 | Total | | | | | | 7,484.51 | | | | | |

| Name of Respondent: Avista Corporation | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/17/2026 | Year/Period of Report End of: 2025/ Q4 |
|---|---|---|---|

**TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES**

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

| Line No. | Description of the Good or Service (a) | Name of Associated/Affiliated Company (b) | Account(s) Charged or Credited (c) | Amount Charged or Credited (d) |
|---|---|---|---|---|
| 1 | **Non-power Goods or Services Provided by Affiliated** | | | |
| 2 | | | | |
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| 17 | | | | |
| 18 | | | | |
| 19 | | | | |
| 20 | **Non-power Goods or Services Provided for Affiliated** | | | |
| 21 | Corporate Support | Avista Development | 146000 | 70,360 |
| 22 | Corporate Support | Avista Capital | 146000 | 86,431 |
| 23 | Corporate Support | AELP | 146000 | 20,526 |
| 42 | | | | |