Oregon Public Utility Commission

e-FILING REPORT COVER SHEET

COMPANY NAME: Avista Corporation

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☒ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

Select report type: ☐ RE (Electric) ☒ RG (Gas) ☐ RW (Water) ☐ RT (Telecommunications)
☐ RO (Other, for example, industry safety information)

Did you previously file a similar report? ☒ No ☐ Yes, report docket number:

Report is required by: ☐ OAR
☒ Statute ORS 757
☐ Order
Note: A one-time submission required by an order is a compliance filing and not a report (file compliance in the applicable docket)
☐ Other
(For example, federal regulations, or requested by Staff)

Is this report associated with a specific docket/case? ☒ No ☐ Yes, docket number:

List Key Words for this report. We use these to improve search results.

Annual Reports for the year ending December 31, 2021 for Avista Corporation; FERC Form 2; Oregon Supplement to Form 2

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@state.or.us

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 201 High Street SE Suite 100, Salem, OR 97301.

Print

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

FERC FINANCIAL REPORT
FERC FORM No. 2: Annual Report of Major Natural Gas Companies and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Natural Gas Act, Sections 10(a), and 16 and 18 CFR Parts 260.1 and 260.300. 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 a confidential nature.

Exact Legal Name of Respondent (Company)	Year/Period of Report:
Avista Corporation	End of: 2021/ Q4

INSTRUCTIONS FOR FILING FERC FORMS 2, 2-A and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Forms 2, 2-A, and 3-Q are designed to collect financial and operational information from natural gas companies subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be a non-confidential public use forms.

II. Who Must Submit

Each natural gas company whose combined gas transported or stored for a fee exceed 50 million dekatherms in each of the previous three years must submit FERC Form 2 and 3-Q.

Each natural gas company not meeting the filing threshold for FERC Form 2, but having total gas sales or volume transactions exceeding 200,000 dekatherms in each of the previous three calendar years must submit FERC Form 2-A and 3-Q.

Newly established entities must use projected data to determine whether they must file the FERC Form 3-Q and FERC Form 2 or 2-A.

III. What and Where to Submit

a. Submit FERC Form Nos. 2, 2-A and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 2, 2-A and 3-Q taxonomies..
b. The Corporate Officer Certification must be submitted electronically as part of the FERC Form 2 and 3-Q filings.
c. Submit immediately upon publication, by either eFiling or mailing two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders and any annual financial or statistical report regularly prepared and distributed to bondholders, security analysts, or industry associations. Do not include monthly and quarterly reports. Indicate by checking the appropriate box on Form 2, Page 3, List of Schedules, if the reports to stockholders will be submitted or if no annual report to stockholders is prepared. Unless eFiling the Annual Report to Stockholders, mail these reports to the Secretary of the Commission at:

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

d. For the Annual CPA certification, submit with the original submission of this form, a letter or report (not applicable to respondents classified as Class C or Class D prior to January 1, 1984) prepared in conformity with the current standards of reporting which will:
   i. Contain a paragraph attesting to the conformity, in all material respects, of the schedules listed below with the Commission's applicable Uniform Systems of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and
   ii. 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. §§ 158.10-158.12 for specific qualifications.)

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

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

e. Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online .
f. Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 2 and 2-A free of charge from: https://www.ferc.gov/industries-data/natural-gas/industry-forms . Copies may also be obtained from the Public Reference and Files Maintenance Branch, Federal Energy Regulatory Commission, 888 First Street, NE. Room 2A, Washington, DC 20426 or by calling (202).502-8371

IV. When to Submit:

FERC Forms 2, 2-A, and 3-Q must be filed by the dates:

a. FERC Form 2 and 2-A --- by April 18th of the following year (18 C.F.R. §§ 260.1 and 260.2)
b. FERC Form 3-Q --- Natural gas companies that file a FERC Form 2 must file the FERC Form 3-Q within 60 days after the reporting

quarter (18 C.F.R.§ 260.300), and

c. FERC Form 3-Q --- Natural gas companies that file a FERC Form 2-A must file the FERC Form 3-Q within 70 days after the reporting quarter (18 C.F.R. § 260.300).

V. **Where to Send Comments on Public Reporting Burden.**

The public reporting burden for the Form 2 collection of information is estimated to average 1,671.66 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 Form 2A collection of information is estimated to average 295.66 hours per response. The public reporting burden for the Form 3-Q collection of information is estimated to average 167 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 all reports in conformity with the Uniform System of Accounts (USofA) (18 C.F.R. Part 201). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or Dth) 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, indicate whether a schedule has been omitted by entering "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, page 2.

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.**

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. Footnote and further explain accounts or pages as necessary.

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

X. 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.

XI. Report all gas volumes in Dth unless the schedule specifically requires the reporting in another unit of measurement.

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

DEFINITIONS

I. <u>Btu per cubic foot</u> – The total heating value, expressed in Btu, produced by the combustion, at constant pressure, of the amount of the gas which would occupy a volume of 1 cubic foot at a temperature of 60°F if saturated with water vapor and under a pressure equivalent to that of 30°F, and under standard gravitational force (980.665 cm. per sec) with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of gas and air when the water formed by combustion is condensed to the liquid state (called gross heating value or total heating value).

II. <u>Commission Authorization</u> -- 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.

III. <u>Dekatherm</u> – A unit of heating value equivalent to 10 therms or 1,000,000 Btu.

IV. <u>Respondent</u> – The person, corporation, licensee, agency, authority, or other legal entity or instrumentality on whose behalf the report is made.

EXCERPTS FROM THE LAW

Natural Gas Act, 15 U.S.C. 717-717w

"Sec. 10(a). Every natural-gas company shall file with the Commission such annual and other periodic or special reports as the Commission may by rules and regulations or order prescribe as necessary or appropriate to assist the Commission in the proper administration of this act. The Commission may prescribe the manner and form in which such reports shall be made and require from such natural-gas companies specific answers to all questions upon which the Commission may need information. The Commission may require that such reports include, among other things, full information as to assets and liabilities, capitalization, investment and reduction thereof, gross receipts, interest dues and paid, depreciation, amortization, and other reserves, cost of facilities, costs of maintenance and operation of facilities for the production, transportation, delivery, use, or sale of natural gas, costs of renewal and replacement of such facilities, transportation, delivery, use and sale of natural gas..."

"Section 16. The Commission shall have power to perform all and any acts, and to prescribe, issue, make, amend, 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 form or forms of all statements declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and time within they shall be filed..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. See NGA § 22(a), 15 U.S.C. §717t-1(a).

FERC FORM NO. 2 REPORT OF MAJOR NATURAL GAS COMPANIES		
IDENTIFICATION		
01 Exact Legal Name of Respondent Avista Corporation		02 Year/ Period of Report End of: 2021/ Q4
03 Previous Name and Date of Change (if name changed during year) /		
04 Address of Principal Office at End of Year (Street, City, State, Zip Code) 1411 East Mission Avenue, Spokane, WA 99207		
05 Name of Contact Person Ryan L. Krasselt		06 Title of Contact Person VP, Controller, Prin Acctg Officer
07 Address of Contact Person (Street, City, State, Zip Code) 1411 East Mission Avenue, Spokane, WA 99207		
08 Telephone of Contact Person, Including Area Code 509-495-2273	09 This Report is An Original / A Resubmission (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 04/18/2022

Annual Corporate Officer Certification	
The undersigned officer certifies that: I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.	
11 Name Ryan L. Krasselt	12 Title VP, Controller, Prin Acctg Officer
13 Signature Ryan L Krasselt	14 Date Signed 04/22/2022
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: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

List of Schedules (Natural Gas Company)

List of Schedules (Natural Gas Company)

Line No.	Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
23	Investments In Subsidiary Companies	224	12-96	
24	Prepayments	230a	12-96	
25	Extraordinary Property Losses	230b	12-96	NA
26	Unrecovered Plant And Regulatory Study Costs	230c	12-96	NA
27	Other Regulatory Assets	232	REV 12-07	
28	Miscellaneous Deferred Debits	233	12-96	
29	Accumulated Deferred Income Taxes	234	REV 12-07	
	BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Other Credits)			
30	Capital Stock	250	12-96	
31	Capital Stock Subscribed, Capital Stock Liability for Conversion, Premium on Capital Stock, and Installments Recieved on Capital Stock	252	12-96	NA
32	Other Paid-In Capital	253	12-96	
33	Discount on Capital Stock	254	12-96	NA
34	Capital Stock Expense	254	12-96	
35	Securities Issued Or Assumed And Securities Refunded Or Retired During The Year	255.1	12-96	
36	Long-Term Debt	256	12-96	
37	Unamortized Debt Expense, Premium And Discount On Long-Term Debt	258	12-96	
38	Unamortized Loss And Gain On Reacquired Debt	260	12-96	
39	Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes	261	12-96	
40	Taxes Accrued, Prepaid And Charged During Year, Distribution Of Taxes Charged	262	REV 12-07	
41	Miscellaneous Current And Accrued Liabilities	268	12-96	
42	Other Deferred Credits	269	12-96	
43	Accumulated Deferred Income Taxes-Other Property (Account 282)	274	REV 12-07	
44	Accumulated Deferred Income Taxes-Other (Account 283)	276	REV 12-07	
45	Other Regulatory Liabilities	278	REV 12-07	
	INCOME ACCOUNT SUPPORTING SCHEDULES			
46	Monthly Quantity & Revenue Data	299	NEW 12-08	NA
47	Gas Operating Revenues	300	REV 12-07	
48	Revenues From Transportation Of Gas Of Others Through Gathering Facilities	302	12-96	NA

List of Schedules (Natural Gas Company)

List of Schedules (Natural Gas Company)				
Line No.	Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
74	Footnote Reference			NA
75	Footnote Text			
76	Stockholder's Reports (check appropriate box)			
	☐ Four copies will be submitted ☐ No annual report to stockholders is prepared			

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

General Information

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

Ryan L Krasselt, VP, Controller, Prin Acctg Officer 1411 East Mission Avenue, Spokane, WA 99207Ryan L. Krasselt

VP, Controller, Prin Acctg Officer

1411 East 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.

WA State 3/15/1889
State of Incorporation: WA

Date of Incorporation: 03/15/1889

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.

None
(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: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Corporations Controlled by Respondent

Line No.	Name of Company Controlled (a)	Type of Control (b)	Kind of Business (c)	Percent Voting Stock Owned (d)	Footnote Reference (e)
1	Avista Capital, Inc.	D	Parent to the Company's subsidiaries	[(a)] [(b)] 100%	
2	Avista Development	I	Investment in Real Estate	[(c)] [(d)] 100%	
3	Avista Edge, Inc.	I	Investment in Technology providing high speed internet	[(e)] [(f)] 100%	
4	Pentzer Corporation	I	Parent of Bay Area Mfg and Penture Venture Holdings	[(g)] [(h)] 100%	
5	Pentzer Venture Holdings II	I	Holding Company-Inactive	[(i)] [(j)] 100%	
6	Bay Area Manufacturing	I	Holding Company	[(k)] [(l)] 100%	
7	Avista Capital II	D	Affiliated business trust issued pref trust Securities	[(m)] [(n)] 100%	
8	Avista Northwest Resources, LLC	I	Owns an interest in a venture fund investment	[(o)] [(p)] 100%	
9	Courtyard Office Center, LLC	I	Office & Retail Leasing	[(q)] [(r)] 100%	
10	Salix, Inc.	I	Liquified Natural Gas Operations	[(s)] [(t)] 100%	
11	Alaska Energy and Resources Company (AERC)	D	Parent Co of Alaska Operations	[(u)] [(v)] 100%	
12	Alaska Electric Light and Power Company	I	Utility Operations in Juneau	[(w)] [(x)] 100%	
13	AJT Mining Properties, Inc.	I	Inactive mining Co holding certain properties	[(y)] [(z)] 100%	
14	Snettisham Electric Company	I	Right to Purchase Snettisham	[(aa)] [(ab)] 100%	

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FOOTNOTE DATA

(a) Concept: VotingStockOwnedByRespondentPercentage
(b) Concept: VotingStockOwnedByRespondentPercentage
(c) Concept: VotingStockOwnedByRespondentPercentage
(d) Concept: VotingStockOwnedByRespondentPercentage
(e) Concept: VotingStockOwnedByRespondentPercentage
(f) Concept: VotingStockOwnedByRespondentPercentage
(g) Concept: VotingStockOwnedByRespondentPercentage
(h) Concept: VotingStockOwnedByRespondentPercentage
(i) Concept: VotingStockOwnedByRespondentPercentage
(j) Concept: VotingStockOwnedByRespondentPercentage
(k) Concept: VotingStockOwnedByRespondentPercentage
(l) Concept: VotingStockOwnedByRespondentPercentage
(m) Concept: VotingStockOwnedByRespondentPercentage
(n) Concept: VotingStockOwnedByRespondentPercentage
(o) Concept: VotingStockOwnedByRespondentPercentage
(p) Concept: VotingStockOwnedByRespondentPercentage
(q) Concept: VotingStockOwnedByRespondentPercentage
(r) Concept: VotingStockOwnedByRespondentPercentage
(s) Concept: VotingStockOwnedByRespondentPercentage
(t) Concept: VotingStockOwnedByRespondentPercentage

(u) Concept: VotingStockOwnedByRespondentPercentage

(v) Concept: VotingStockOwnedByRespondentPercentage
(w) Concept: VotingStockOwnedByRespondentPercentage
(x) Concept: VotingStockOwnedByRespondentPercentage
(y) Concept: VotingStockOwnedByRespondentPercentage
(z) Concept: VotingStockOwnedByRespondentPercentage
(aa) Concept: VotingStockOwnedByRespondentPercentage
(ab) Concept: VotingStockOwnedByRespondentPercentage

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Security Holders and Voting Powers

Line No.	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES 4. Number of votes as of (date): 12/31/2021

1. Give date of the latest closing of the stock book prior to end of year, and, in a footnote, state the purpose of such closing: 11/29/2021	2. State the total number of votes cast at the latest general meeting prior to the end of year for election of directors of the respondent and number of such votes cast by proxy. Total: 62,187,196 By Proxy: 62,187,196	3. Give the date and place of such meeting: 05/11/2021

Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
5	TOTAL votes of all voting securities	71,497,523	
6	TOTAL number of security holders	6,572	
7	TOTAL votes of security holders listed below	36,404,713	
8	BlackRock Institutional Trust, 55 East 52nd Street, New York, NY 10055	12,185,965	
9	The Vanguard Group, 100 Vanguard Blvd., Malvern, PA 19355	8,230,974	
10	PSP Investments, 1250 Rene-Levesque West, Suite 1400, Montreal, QC, H3B 5E9 Canada	3,825,490	
11	Nuance Investments, LLC, Kansas City, MO	2,632,342	
12	State Street Global Advisors (US), Boston, MA	2,606,720	
13	First Trust Advisors, Wheaton, IL	1,668,366	
14	Hotchkis and Wiley Capital Management, Los Angeles, CA	1,457,164	
15	Mitsubishi UFJ Trust and Banking, Tokyo Japan	1,339,153	
16	Dimensional Fund Advisors, Austin, TX	1,270,841	
17	Geode Capital Management, Boston, MA	1,187,698	

Security Holders and Voting Powers

Line No.	VOTING SECURITIES 4. Number of votes as of (date): 12/31/2021	VOTING SECURITIES 4. Number of votes as of (date): 12/31/2021	
1. Give date of the latest closing of the stock book prior to end of year, and, in a footnote, state the purpose of such closing: 11/29/2021	2. State the total number of votes cast at the latest general meeting prior to the end of year for election of directors of the respondent and number of such votes cast by proxy. Total: 62,187,196 By Proxy: 62,187,196		3. Give the date and place of such meeting: 05/11/2021
Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
5	71,497,523		
6	6,572		
7	36,404,713		
8	12,185,965		
9	8,230,974		
10	3,825,490		
11	2,632,342		
12	2,606,720		
13	1,668,366		
14	1,457,164		
15	1,339,153		
16	1,270,841		
17	1,187,698		

Security Holders and Voting Powers

Line No.	VOTING SECURITIES 4. Number of votes as of (date): 12/31/2021		
1. Give date of the latest closing of the stock book prior to end of year, and, in a footnote, state the purpose of such closing: 11/29/2021		2. State the total number of votes cast at the latest general meeting prior to the end of year for election of directors of the respondent and number of such votes cast by proxy. Total: 62,187,196 By Proxy: 62,187,196	3. Give the date and place of such meeting: 05/11/2021

Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
5			
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Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Important Changes During the Year

Give details concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Answer each inquiry. Enter "none" or "not applicable" where applicable. If the answer is given elsewhere in the report, refer to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration and state from whom the franchise rights were acquired. If the franchise rights were 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: Briefly describe the property, and the related transactions, and cite Commission authorization, if any was required. Give date journal entries called for by 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 conditions. 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 cite 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 or assumed by respondent as guarantor for the performance by another of any agreement or obligation, including ordinary commercial paper maturing on demand or not later than one year after date of issue: State on behalf of whom the obligation was assumed and amount of the obligation. Cite Commission authorization if any was required.
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, 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. Estimated increase or decrease in annual revenues caused by important rate changes: State effective date and approximate amount of increase or decrease for each revenue classification. State the number of customers affected.
12. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
13. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

1. None

2. None

3. None

4. None

5. None

6. References made to notes 11, 12, 13 and 14 of the Notes to the Financial Statements.

7. None

8. Average annual wage increases were 3.0% for non-exempt employees effective March 1, 2021. Average annual wage increases were 3.0% for exempt employees effective March 1, 2021. Officers received averaged increases of 5.2% effective February 15, 2021. Certain bargaining unit employees received increases of 2.0% effective April 1, 2021.
9. Reference is made to Note 12 of the notes to Financial Statements.
10. None
11. Reserved
12. Effective May11, 2021, Sena Kwawu was elected by the shareholders of the company to join the Avista Corp. board of directors. Effective May11, 2021, Marc Racicot retired from the board of directors. Effective June21, 2021, R. John Taylor resigned from the board of directors. Effective August 11, 2021 Major General (Retired) Julie Bentz was appointed by the board of directors and has joined the board effective November 1, 2021.
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: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Comparative Balance Sheet (Assets And Other Debits)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200-201	7,072,675,570	6,713,727,078
3	Construction Work in Progress (107)	200-201	196,305,682	172,073,892
4	TOTAL Utility Plant (Total of lines 2 and 3)	200-201	7,268,981,252	6,885,800,970
5	(Less) Accum. Provision for Depr., Amort., Depl. (108, 111, 115)		2,465,058,317	2,294,362,603
6	Net Utility Plant (Total of line 4 less 5)		4,803,922,935	4,591,438,367
7	Nuclear Fuel (120.1 thru 120.4, and 120.6)		0	
8	(Less) Accum. Provision for Amort., of Nuclear Fuel Assemblies (120.5)		0	
9	Nuclear Fuel (Total of line 7 less 8)		0	
10	Net Utility Plant (Total of lines 6 and 9)		4,803,922,935	4,591,438,367
11	Utility Plant Adjustments (116)	122	0	
12	Gas Stored-Base Gas (117.1)	220	6,992,076	6,992,076
13	System Balancing Gas (117.2)	220	0	
14	Gas Stored in Reservoirs and Pipelines-Noncurrent (117.3)	220	0	
15	Gas Owed to System Gas (117.4)	220	0	
16	OTHER PROPERTY AND INVESTMENTS			
17	Nonutility Property (121)		4,500,764	5,311,287
18	(Less) Accum. Provision for Depreciation and Amortization (122)		247,981	212,107
19	Investments in Associated Companies (123)	222-223	11,547,000	11,547,000
20	Investments in Subsidiary Companies (123.1)	224-225	225,965,712	207,410,330
22	Noncurrent Portion of Allowances		0	
23	Other Investments (124)	222-223	77,890	77,890
24	Sinking Funds (125)		0	
25	Depreciation Fund (126)		0	
26	Amortization Fund - Federal (127)		0	
27	Other Special Funds (128)		11,152,367	24,673,076
28	Long-Term Portion of Derivative Assets (175)		2,658,520	596,015
29	Long-Term Portion of Derivative Assets - Hedges (176)		0	

Comparative Balance Sheet (Assets And Other Debits)				
Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
30	TOTAL Other Property and Investments (Total of lines 17-20, 22-29)		255,654,272	249,403,491
31	CURRENT AND ACCRUED ASSETS			
32	Cash (131)		11,893,219	7,363,358
33	Special Deposits (132-134)		21,477,352	4,335,989
34	Working Funds (135)		1,227,292	1,116,351
35	Temporary Cash Investments (136)	222-223	153,241	152,774
36	Notes Receivable (141)		0	
37	Customer Accounts Receivable (142)		183,224,129	161,513,344
38	Other Accounts Receivable (143)		50,330,014	56,664,630
39	(Less) Accum. Provision for Uncollectible Accounts - Credit (144)		10,368,511	11,336,140
40	Notes Receivable from Associated Companies (145)		0	
41	Accounts Receivable from Associated Companies (146)		738,517	719,507
42	Fuel Stock (151)		4,388,454	4,088,628
43	Fuel Stock Expenses Undistributed (152)		0	
44	Residuals (Elec) and Extracted Products (Gas) (153)		0	
45	Plant Materials and Operating Supplies (154)		60,277,408	51,854,056
46	Merchandise (155)		0	
47	Other Materials and Supplies (156)		0	
48	Nuclear Materials Held for Sale (157)		0	
49	Allowances (158.1 and 158.2)		0	
50	(Less) Noncurrent Portion of Allowances		0	
51	Stores Expense Undistributed (163)		0	
52	Gas Stored Underground-Current (164.1)	220	[(a)]17,603,996	9,535,324
53	Liquefied Natural Gas Stored and Held for Processing (164.2 thru 164.3)	220	0	
54	Prepayments (165)	230	22,973,644	26,280,659
55	Advances for Gas (166 thru 167)		0	
56	Interest and Dividends Receivable (171)		20,633	24,973
57	Rents Receivable (172)		3,665,325	2,934,798
58	Accrued Utility Revenues (173)		0	

Comparative Balance Sheet (Assets And Other Debits)				
Line No.	**Title of Account (a)**	**Reference Page Number (b)**	**Current Year End of Quarter/Year Balance (c)**	**Prior Year End Balance 12/31 (d)**
59	Miscellaneous Current and Accrued Assets (174)		113,893	236,392
60	Derivative Instrument Assets (175)		4,056,941	1,523,219
61	(Less) Long-Term Portion of Derivative Instrument Assets (175)		2,658,520	596,015
62	Derivative Instrument Assets - Hedges (176)		0	
63	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		0	
64	TOTAL Current and Accrued Assets (Total of lines 32 thru 63)		369,117,027	316,411,847
65	DEFERRED DEBITS			
66	Unamortized Debt Expense (181)		16,420,883	15,341,338
67	Extraordinary Property Losses (182.1)	230	0	
68	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	
69	Other Regulatory Assets (182.3)	232	833,162,908	717,281,643
70	Preliminary Survey and Investigation Charges (Electric)(183)		0	
71	Preliminary Survey and Investigation Charges (Gas)(183.1 and 183.2)		0	
72	Clearing Accounts (184)		122,784	152,201
73	Temporary Facilities (185)		0	
74	Miscellaneous Deferred Debits (186)	233	50,762,924	29,826,563
75	Deferred Losses from Disposition of Utility Plant (187)		0	
76	Research, Development, and Demonstration Expend. (188)		0	
77	Unamortized Loss on Reacquired Debt (189)		6,768,288	7,512,371
78	Accumulated Deferred Income Taxes (190)	234-235	256,362,574	216,728,536
79	Unrecovered Purchased Gas Costs (191)		21,025,867	1,433,580
80	TOTAL Deferred Debits (Total of lines 66 thru 79)		1,184,626,228	988,276,232
81	TOTAL Assets and Other Debits (Total of lines 10-15,30,64,and 80)		6,620,312,538	6,152,522,013

FOOTNOTE DATA

(a) Concept: GasStoredCurrent
Fuel is accounted for within injections and withdrawal accounts. All gas reported is current working gas. Avista uses the inventory method to report all working gas stored.

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Comparative Balance Sheet (Liabilities and Other Credits)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	1,341,011,707	1,249,688,206
3	Preferred Stock Issued (204)	250-251	0	
4	Capital Stock Subscribed (202, 205)	252	0	
5	Stock Liability for Conversion (203, 206)	252	0	
6	Premium on Capital Stock (207)	252	0	
7	Other Paid-In Capital (208-211)	253	(10,696,711)	(10,696,711)
8	Installments Received on Capital Stock (212)	252	0	
9	(Less) Discount on Capital Stock (213)	254	0	
10	(Less) Capital Stock Expense (214)	254	(49,837,072)	(47,076,877)
11	Retained Earnings (215, 215.1, 216)	118-119	781,020,474	771,613,505
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	4,609,991	(13,577,380)
13	(Less) Reacquired Capital Stock (217)	250-251	0	
14	Accumulated Other Comprehensive Income (219)	117	(11,038,551)	(14,378,164)
15	TOTAL Proprietary Capital (Total of lines 2 thru 14)		2,154,743,982	2,029,726,333
16	LONG TERM DEBT			
17	Bonds (221)	256-257	2,157,200,000	2,017,200,000
18	(Less) Reacquired Bonds (222)	256-257	83,700,000	83,700,000
19	Advances from Associated Companies (223)	256-257	51,547,000	51,547,000
20	Other Long-Term Debt (224)	256-257	0	
21	Unamortized Premium on Long-Term Debt (225)	258-259	124,367	133,250
22	(Less) Unamortized Discount on Long-Term Debt-Dr (226)	258-259	757,032	843,651
23	(Less) Current Portion of Long-Term Debt		0	
24	TOTAL Long-Term Debt (Total of lines 17 thru 23)		2,124,414,335	1,984,336,599
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases-Noncurrent (227)		66,068,171	67,716,314
27	Accumulated Provision for Property Insurance (228.1)		0	

Comparative Balance Sheet (Liabilities and Other Credits)				
Line No.	**Title of Account (a)**	**Reference Page Number (b)**	**Current Year End of Quarter/Year Balance (c)**	**Prior Year End Balance 12/31 (d)**
28	Accumulated Provision for Injuries and Damages (228.2)		731,009	395,000
29	Accumulated Provision for Pensions and Benefits (228.3)		153,467,368	211,880,118
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	
31	Accumulated Provision for Rate Refunds (229)		409,971	3,820,594
32	Long-Term Portion of Derivative Instrument Liabilities		4,525,064	37,427,277
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	
34	Asset Retirement Obligations (230)		17,141,793	17,194,050
35	TOTAL Other Noncurrent Liabilities (Total of lines 26 thru 34)		242,343,376	338,433,353
36	CURRENT AND ACCRUED LIABILITIES			
37	Current Portion of Long-Term Debt		0	
38	Notes Payable (231)		284,000,000	202,000,000
39	Accounts Payable (232)		127,662,676	104,217,591
40	Notes Payable to Associated Companies (233)		1,404,714	8,742,915
41	Accounts Payable to Associated Companies (234)		18,595	
42	Customer Deposits (235)		3,702,706	3,028,142
43	Taxes Accrued (236)	262-263	41,669,378	45,266,874
44	Interest Accrued (237)		16,347,042	15,884,942
45	Dividends Declared (238)		0	
46	Matured Long-Term Debt (239)		0	
47	Matured Interest (240)		0	
48	Tax Collections Payable (241)		137,825	111,813
49	Miscellaneous Current and Accrued Liabilities (242)	268	69,109,875	60,781,094
50	Obligations Under Capital Leases-Current (243)		4,300,958	4,249,213
51	Derivative Instrument Liabilities (244)		33,326,256	51,435,582
52	(Less) Long-Term Portion of Derivative Instrument Liabilities		4,525,064	37,427,277
53	Derivative Instrument Liabilities - Hedges (245)		0	
54	(Less) Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	

Comparative Balance Sheet (Liabilities and Other Credits)				
Line No.	**Title of Account (a)**	**Reference Page Number (b)**	**Current Year End of Quarter/Year Balance (c)**	**Prior Year End Balance 12/31 (d)**
55	TOTAL Current and Accrued Liabilities (Total of lines 37 thru 54)		577,154,961	458,290,889
56	DEFERRED CREDITS			
57	Customer Advances for Construction (252)		3,624,489	2,444,383
58	Accumulated Deferred Investment Tax Credits (255)		29,313,176	29,866,627
59	Deferred Gains from Disposition of Utility Plant (256)		0	
60	Other Deferred Credits (253)	269	30,183,652	31,450,029
61	Other Regulatory Liabilities (254)	278	571,662,225	473,121,377
62	Unamortized Gain on Reacquired Debt (257)	260	1,189,285	1,318,822
63	Accumulated Deferred Income Taxes - Accelerated Amortization (281)		0	
64	Accumulated Deferred Income Taxes - Other Property (282)		618,900,933	603,415,433
65	Accumulated Deferred Income Taxes - Other (283)		266,782,124	200,118,168
66	TOTAL Deferred Credits (Total of lines 57 thru 65)		1,521,655,884	1,341,734,839
67	TOTAL Liabilities and Other Credits (Total of lines 15,24,35,55,and 66)		6,620,312,538	6,152,522,013

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Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Statement of Income

Line No.	Title of Account (a)	Reference Page Number (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)
1	UTILITY OPERATING INCOME					
2	Gas Operating Revenues (400)	300-301	1,495,585,923	1,379,875,645		
3	Operating Expenses					
4	Operation Expenses (401)	317-325	865,148,582	762,581,592		
5	Maintenance Expenses (402)	317-325	80,137,861	74,568,922		
6	Depreciation Expense (403)	336-338	177,443,227	181,300,837		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-338	0			
8	Amort. & Depl. of Utility Plant (404-405)	336-338	53,212,301	44,668,607		
9	Amortization of Utility Plant Acu. Adjustment (406)	336-338	99,047	99,047		
10	Amort. of Prop. Losses, Unrecovered Plant and Reg. Study Costs (407.1)		0			
11	Amortization of Conversion Expenses (407.2)		0			
12	Regulatory Debits (407.3)		14,824,439	12,453,020		
13	(Less) Regulatory Credits (407.4)		52,533,715	57,223,861		
14	Taxes Other Than Income Taxes (408.1)	262-263	116,909,168	114,634,576		
15	Income Taxes-Federal (409.1)	262-263	846,571	(41,194,492)		
16	Income Taxes-Other (409.1)	262-263	876,303	654,441		
17	Provision of Deferred Income Taxes (410.1)	234-235	151,017,644	134,834,319		
18	(Less) Provision for Deferred Income Taxes-Credit (411.1)	234-235	144,624,499	82,145,804		
19	Investment Tax Credit Adjustment-Net (411.4)		(553,452)	(577,334)		
20	(Less) Gains from Disposition of Utility Plant (411.6)		0			
21	Losses from Disposition of Utility Plant (411.7)		0			
22	(Less) Gains from Disposition of Allowances (411.8)		0			

Statement of Income						
Line No.	**Title of Account (a)**	**Reference Page Number (b)**	**Total Current Year to Date Balance for Quarter/Year (c)**	**Total Prior Year to Date Balance for Quarter/Year (d)**	**Current Three Months Ended Quarterly Only No Fourth Quarter (e)**	**Prior Three Months Ended Quarterly Only No Fourth Quarter (f)**
23	Losses from Disposition of Allowances (411.9)		0			
24	Accretion Expense (411.10)		0			
25	TOTAL Utility Operating Expenses (Total of lines 4 thru 24)		1,262,803,477	1,144,653,870		
26	Net Utility Operating Income (Total of lines 2 less 25)		232,782,446	235,221,775		
28	OTHER INCOME AND DEDUCTIONS					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Expense of Merchandising, Job & Contract Work (416)		0			
33	Revenues From Nonutility Operations (417)		299,756	108,256		
34	(Less) Expenses of Nonutility Operations (417.1)		5,295,279	5,439,625		
35	Nonoperating Rental Income (418)		(31,838)	(31,838)		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	23,555,382	5,304,376		
37	Interest and Dividend Income (419)		3,650,892	3,448,647		
38	Allowance for Other Funds Used During Construction (419.1)		589,900	338,811		
39	Miscellaneous Nonoperating Income (421)		0			
40	Gain on Disposition of Property (421.1)		109,527	289,281		
41	TOTAL Other Income (Total of lines 31 thru 40)		22,878,340	4,017,908		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		0			
44	Miscellaneous Amortization (425)		5,616	(815,484)		
45	Donations (426.1)	340	2,499,499	2,999,603		
46	Life Insurance (426.2)		3,591,498	3,072,596		

Statement of Income						
Line No.	Title of Account (a)	Reference Page Number (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)
47	Penalties (426.3)		22,039	(17,039)		
48	Expenditures for Certain Civic, Political and Related Activities (426.4)		1,935,266	1,773,265		
49	Other Deductions (426.5)		4,448,958	3,494,856		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)	340	12,502,876	10,507,797		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	564,779	923,792		
53	Income Taxes-Federal (409.2)	262-263	(1,628,247)	(60,470)		
54	Income Taxes-Other (409.2)	262-263	(472,315)	800		
55	Provision for Deferred Income Taxes (410.2)	234-235	3,042,777	218,831		
56	(Less) Provision for Deferred Income Taxes-Credit (411.2)	234-235	2,944,321	3,167,528		
57	Investment Tax Credit Adjustments-Net (411.5)		0			
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		(1,437,327)	(2,084,575)		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		11,812,791	(4,405,314)		
61	INTEREST CHARGES					
62	Interest on Long-Term Debt (427)		91,728,400	88,943,778		
63	Amortization of Debt Disc. and Expense (428)	258-259	941,948	937,453		
64	Amortization of Loss on Reacquired Debt (428.1)		1,592,056	2,222,423		
65	(Less) Amortization of Premium on Debt-Credit (429)	258-259	8,883	8,883		
66	(Less) Amortization of Gain on Reacquired Debt-Credit (429.1)					
67	Interest on Debt to Associated Companies (430)	340	515,447	186,289		
68	Other Interest Expense (431)	340	4,860,055	6,170,081		

Statement of Income						
Line No.	Title of Account (a)	Reference Page Number (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)
69	(Less) Allowance for Borrowed Funds Used During Construction-Credit (432)		2,367,356	2,152,002		
70	Net Interest Charges (Total of lines 62 thru 69)		97,261,667	96,299,139		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		147,333,570	134,517,322		
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)	262-263	0	0		
77	Extraordinary Items after Taxes (line 75 less line 76)		0	0		
78	Net Income (Total of line 71 and 77)		147,333,570	[(a)]134,517,322		

Statement of Income						
Line No.	Elec. Utility Current Year to Date (in dollars) (g)	Elec. 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						
2	1,022,015,983	942,731,364	473,569,940	437,144,281		
3						
4	557,603,571	479,296,895	307,545,011	283,284,697		
5	64,169,603	58,433,891	15,968,258	16,135,031		
6	136,516,432	142,059,284	40,926,795	39,241,553		
7	0		0			
8	39,430,494	32,861,811	13,781,807	11,806,796		
9	99,047	99,047	0			
10						
11	0		0			
12	9,015,832	8,161,579	5,808,607	4,291,441		
13	46,406,409	47,876,238	6,127,306	9,347,623		
14	87,398,430	86,303,016	29,510,738	28,331,560		
15	(1,109,426)	(21,919,271)	1,955,997	(19,275,221)		
16	30,939	(214,113)	845,364	868,554		
17	88,830,716	83,467,206	62,186,928	51,367,113		
18	83,402,751	61,963,304	61,221,748	20,182,500		
19	(548,446)	(562,691)	(5,006)	(14,643)		
20						
21						
22						
23						
24						
25	851,628,032	758,147,112	411,175,445	386,506,758	0	
26	170,387,951	184,584,252	62,394,495	50,637,523	0	
28						
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Statement of Income						
Line No.	Elec. Utility Current Year to Date (in dollars) (g)	Elec. 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)
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Statement of Income						
Line No.	Elec. Utility Current Year to Date (in dollars) (g)	Elec. 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)
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Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: NetIncomeLoss

Duplicate fact discrepancy. Schedule: 122a - Schedule - Statement of Accumulated Other Comprehensive Income, Comprehensive Income, and Hedging Activities, Row: 9, Column: i, Value: 134517321

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Statement of Accumulated Comprehensive Income and Hedging Activities

1. Report in columns (b) (c) 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.

Line No.	Item (a)	Unrealized Gains and Losses on available-for-sale securities (b)	Minimum Pension liabililty Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Insert Footnote at Line 1 to specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 114, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year		(10,258,024)					(10,258,024)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income									
3	Preceding Quarter/Year to Date Changes in Fair Value		(4,120,140)					(4,120,140)		
4	Total (lines 2 and 3)		(4,120,140)					(4,120,140)	[a]134,517,322	130,397,182
5	Balance of Account 219 at End of Preceding Quarter/Year		(14,378,164)					(14,378,164)		
6	Balance of Account 219 at Beginning of Current Year		(14,378,164)					(14,378,164)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income									
8	Current Quarter/Year to Date Changes in Fair Value		3,339,613					3,339,613		
9	Total (lines 7 and 8)		3,339,613					3,339,613	147,333,570	150,673,183

Statement of Accumulated Comprehensive Income and Hedging Activities										
Line No.	Item (a)	Unrealized Gains and Losses on available-for-sale securities (b)	Minimum Pension liabililty Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Insert Footnote at Line 1 to specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 114, Line 78) (i)	Total Comprehensive Income (j)
10	Balance of Account 219 at End of Current Quarter/Year		(11,038,551)					(11,038,551)		

FERC FORM No. 2 (NEW 06-02)

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: NetIncomeLoss

Duplicate fact discrepancy. Schedule: 122a - Schedule - Statement of Accumulated Other Comprehensive Income, Comprehensive Income, and Hedging Activities, Row: 9, Column: i, Value: 134517321

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Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Statement of Retained Earnings

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS			
1	Balance-Beginning of Period		726,160,557	705,980,176
2	Changes (Identify by prescribed retained earnings accounts)			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit (Debit)			
6	Balance Transferred from Income (Account 433 less Account 418.1)		123,778,188	129,212,946
7	Appropriations of Retained Earnings (Account 436)			
7.1	Excess Earnings		(6,065,368)	(4,274,423)
8	Appropriations of Retained Earnings Amount			
9	Dividends Declared-Preferred Stock (Account 437)			
10	Dividends Declared-Preferred Stock Amount			
11	Dividends Declared-Common Stock (Account 438)			
11.1	Dividends		(119,739,230)	(110,253,196)
12	Dividends Declared-Common Stock Amount			
13	Transfers from Account 216.1, Unappropriated Undistributed Subsidiary Earnings		5,368,011	5,495,054
14	Balance-End of Period (Total of lines 1, 4, 5, 6, 8, 10, 12, and 13)		729,502,158	726,160,557
15	APPROPRIATED RETAINED EARNINGS (Account 215)			
16	TOTAL Appropriated Retained Earnings (Account 215) (footnote details)		51,518,316	45,452,948
17	APPROPRIATED RETAINED EARNINGS-AMORTIZATION RESERVE, FEDERAL (Account 215.1)			
18	TOTAL Appropriated Retained Earnings-Amortization Reserve, Federal (Account 215.1)			
19	TOTAL Appropriated Retained Earnings (Accounts 215, 215.1) (Total of lines of 16 and 18)		51,518,316	45,452,948
20	TOTAL Retained Earnings (Accounts 215, 215.1, 216) (Total of lines 14 and 19)		781,020,474	771,613,505
21	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account 216.1)			

Statement of Retained Earnings				
Line No.	**Item (a)**	**Contra Primary Account Affected (b)**	**Current Quarter/Year Year to Date Balance (c)**	**Previous Quarter/Year Year to Date Balance (d)**
	Report only on an Annual Basis no Quarterly			
22	Balance-Beginning of Year (Debit or Credit)		(13,577,380)	(13,386,701)
23	Equity in Earnings for Year (Credit) (Account 418.1)		23,555,382	5,304,376
24	(Less) Dividends Received (Debit)		5,000,000	5,000,000
25	Other Changes (Explain)		(368,011)	(495,055)
25.1	Corporate Costs Allocated to Subsidiaries		(368,011)	(495,055)
26	Balance-End of Year		4,609,991	(13,577,380)

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Statement of Cash Flows

Line No.	Description (See Instructions 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 114)	147,333,570	[(a)]134,517,322
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	230,655,529	225,969,444
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of deferred power and gas costs, debt expense and exchange power	(50,052,091)	(6,772,236)
6	Deferred Income Taxes (Net)	6,486,442	49,739,817
7	Investment Tax Credit Adjustments (Net)	(553,451)	(577,334)
8	Net (Increase) Decrease in Receivables	(25,394,061)	(51,466,229)
9	Net (Increase) Decrease in Inventory	(16,791,851)	(464,901)
10	Net (Increase) Decrease in Allowances Inventory		
11	Net Increase (Decrease) in Payables and Accrued Expenses	36,379,201	6,150,782
12	Net (Increase) Decrease in Other Regulatory Assets	(12,914,300)	(9,597,307)
13	Net Increase (Decrease) in Other Regulatory Liabilities	(219,421)	(4,626,804)
14	(Less) Allowance for Other Funds Used During Construction	6,923,631	6,711,875
15	(Less) Undistributed Earnings from Subsidiary Companies	23,555,382	5,304,376
16	Other Adjustments to Cash Flows from Operating Activities		
16.1	Power and natural gas deferrals	544,574	1,092,888
16.2	Change in special deposits	(17,564,058)	1,579,362
16.3	Change in other current assets	2,703,327	(861,790)
16.4	Non-cash stock compensation	4,712,916	5,846,058
16.5	Gain on sale of property and equipment	(109,527)	(289,281)
16.6	Other	1,171,392	195,316
16.7	Allowance for Doubtful Accounts	4,134,701	4,149,939
16.8	Changes in other non-current asset	(4,576,245)	8,520,219
16.9	Cash settlement of interest rate swaps	(17,244,100)	(33,499,271)
18	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 16)	258,223,534	317,589,743
20	Cash Flows from Investment Activities:		

Statement of Cash Flows			
Line No.	Description (See Instructions for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
21	Construction and Acquisition of Plant (including land):		
22	Gross Additions to Utility Plant (less nuclear fuel)	(441,862,369)	(399,504,892)
23	Gross Additions to Nuclear Fuel		
24	Gross Additions to Common Utility Plant		
25	Gross Additions to Nonutility Plant		
26	(Less) Allowance for Other Funds Used During Construction		
27	Other Construction and Acquisition of Plant, Investment Activities		
28	Cash Outflows for Plant (Total of lines 22 thru 27)	(441,862,369)	(399,504,892)
30	Acquisition of Other Noncurrent Assets (d)		
31	Proceeds from Disposal of Noncurrent Assets (d)	923,995	570,225
33	Investments in and Advances to Associated and Subsidiary Companies	(7,338,616)	(6,476,269)
34	Contributions and Advances from Associated and Subsidiary Companies	5,000,000	5,000,000
36	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
38	Purchase of Investment Securities (a)		
39	Proceeds from Sales of Investment Securities (a)		
40	Loan Made or Purchased		
41	Collections on Loans		
43	Net (Increase) Decrease in Receivables		
44	Net (Increase) Decrease in Inventory		
45	Net (Increase) Decrease in Allowances Held for Speculation		
46	Net Increase (Decrease) in Payables and Accrued Expenses		
47	Other Adjustments to Cash Flows from Investment Activities:		
47.1	Changes in other property and investments	(45,145)	(1,362,792)
49	Net Cash Provided by (Used in) Investing Activities (Total of lines 28 thru 47)	(443,322,135)	(401,773,728)
51	Cash Flows from Financing Activities:		
52	Proceeds from Issuance of:		
53	Proceeds from Issuance of Long-Term Debt (b)	140,000,000	165,000,000
54	Proceeds from Issuance of Preferred Stock		

Statement of Cash Flows			
Line No.	Description (See Instructions for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
55	Proceeds from Issuance of Common Stock	89,997,928	72,200,592
56	Net Increase in Debt (Long Term Advances)		
57	Net Increase in Short-term Debt (c)	82,000,000	19,700,000
59	Cash Provided by Outside Sources (Total of lines 53 thru 58)	311,997,928	256,900,592
61	Payments for Retirement		
62	Payments for Retirement of Long-Term Debt (b)		(52,000,000)
63	Payments for Retirement of Preferred Stock		
64	Payments for Retirement of Common Stock	(141,494)	
65	Other Retirements		
65.1	Other	(3,905,992)	(5,785,023)
66	Net Decrease in Short-Term Debt (c)		
67	Other Adjustments to Financing Cash Flows		
68	Dividends on Preferred Stock		
69	Dividends on Common Stock	(118,210,572)	(110,253,196)
70	Net Cash Provided by (Used in) Financing Activities (Total of lines 59 thru 69)	189,739,870	88,862,373
73	Net Increase (Decrease) in Cash and Cash Equivalents		
74	(Total of line 18, 49 and 71)	4,641,269	4,678,388
76	Cash and Cash Equivalents at Beginning of Period	8,632,483	3,954,095
78	Cash and Cash Equivalents at End of Period	13,273,752	8,632,483

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: NetIncomeLoss

Duplicate fact discrepancy. Schedule: 122a - Schedule - Statement of Accumulated Other Comprehensive Income, Comprehensive Income, and Hedging Activities, Row: 9, Column: i, Value: 134517321

Notes to Financial Statements

1. Provide important disclosures regarding the Balance Sheet, Statement of Income for the Year, Statement of Retained Earnings for the Year, and Statement of Cash Flow, or any account thereof. Classify the disclosures according to each financial statement, providing a subheading for each statement except where a disclosure is applicable to more than one statement. The disclosures must be on the same subject matters and in the same level of detail that would be required if the respondent issued general purpose financial statements to the public or shareholders.
2. Furnish details as to any significant contingent assets or liabilities existing at year end, and briefly explain any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or a claim for refund of income taxes of a material amount initiated by the utility. Also, briefly explain any dividends in arrears on cumulative preferred stock.
3. Furnish details on the respondent's pension plans, post-retirement benefits other than pensions (PBOP) plans, and post-employment benefit plans as required by instruction no. 1 and, in addition, disclose for each individual plan the current year's cash contributions. Furnish details on the accounting for the plans and any changes in the method of accounting for them. Include details on the accounting for transition obligations or assets, gains or losses, the amounts deferred and the expected recovery periods. Also, disclose any current year's plan or trust curtailments, terminations, transfers, or reversions of assets. Entities that participate in multiemployer postretirement benefit plans (e.g. parent company sponsored pension plans) disclose in addition to the required disclosures for the consolidated plan, (1) the amount of cost recognized in the respondent’s financial statements for each plan for the period presented, and (2) the basis for determining the respondent’s share of the total plan costs.
4. Furnish details on the respondent’s asset retirement obligations (ARO) as required by instruction no. 1 and, in addition, disclose the amounts recovered through rates to settle such obligations. Identify any mechanism or account in which recovered funds are being placed (i.e. trust funds, insurance policies, surety bonds). Furnish details on the accounting for the asset retirement obligations and any changes in the measurement or method of accounting for the obligations. Include details on the accounting for settlement of the obligations and any gains or losses expected or incurred on the settlement.
5. Provide a list of all environmental credits received during the reporting period.
6. Provide a summary of revenues and expenses for each tracked cost and special surcharge.
7. Where Account 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 item. See General Instruction 17 of the Uniform System of Accounts.
8. Explain concisely any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
9. Disclose details on any significant financial changes during the reporting year to the respondent or the respondent's consolidated group that directly affect the respondent's gas pipeline operations, including: sales, transfers or mergers of affiliates, investments in new partnerships, sales of gas pipeline facilities or the sale of ownership interests in the gas pipeline to limited partnerships, investments in related industries (i.e., production, gathering), major pipeline investments, acquisitions by the parent corporation(s), and distributions of capital.
10. Explain concisely unsettled rate proceedings where a contingency exists such that the company may need to refund a material amount to the utility's customers or that the utility may receive a material refund 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 and explain the major factors that affect the rights of the utility to retain such revenues or to recover amounts paid with respect to power and gas purchases.
11. Explain concisely 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 summarize the adjustments made to balance sheet, income, and expense accounts.
12. Explain concisely only those significant 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 approximate dollar effect of such changes.
13. 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.
14. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
15. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

NOTES TO FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

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

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

Avista Capital, a wholly owned non-regulated subsidiary of Avista Corp., is the parent company of all 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 Regulatory Commission (FERC) as set forth in its applicable Uniform Systems of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (U.S. GAAP). As required by the FERC, the Company accounts for its investment in majority owned subsidiaries on the equity method rather than consolidating the assets, liabilities, revenues and expenses of these subsidiaries as required by U.S. GAAP. The accompanying financial statements include the Company's proportionate share of utility plant and related operations resulting from its interests in jointly owned plants. In addition, under the requirements of the FERC, there are differences from U.S. GAAP in the presentation of (1) current portion of long-term debt, (2) assets and liabilities for cost of removal of assets, (3) assets held for Sale, (4) regulatory assets and liabilities, (5) deferred income taxes associated with accounts other than utility property, plant and equipment, (6) comprehensive income, (7) unamortized debt issuance costs, (8) operating revenues and resource costs associated with settled energy contracts that are "booked out", (9) non-service portion of pension and other postretirement benefit costs, and (10) leases.

Use of Estimates

The preparation of the financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported for assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates include:

- determining the market value of energy commodity derivative assets and liabilities,
- pension and other postretirement benefit plan obligations,
- contingent liabilities,
- goodwill impairment testing for goodwill held at subsidiaries,
- 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 also 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:

	2021	2020
Avista Utilities		
Ratio of depreciation to average depreciable property	3.54%	3.43%

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

	Avista Utilities
Electric thermal/other production	26
Hydroelectric production	81
Electric transmission	50
Electric distribution	39
Natural gas distribution property	44
Other shorter-lived general plant	8

Allowance for Funds Used During Construction (AFUDC)

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

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

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

	2021	2020
Avista Corp.	7.19%	7.25%

Income Taxes

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

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

The Company did not incur any penalties on income tax positions in 2021or 2020. The Company would recognize interest accrued related to income tax positions as interest expense and any penalties incurred as other operating expense.

Stock-Based Compensation

The Company currently issues three types of stock-based compensation awards - restricted shares, market-based awards and performance-based awards. Historically, these stock compensation awards have not been material to the Company's overall financial results. Compensation cost relating to share-based payment transactions is recognized in the Company's financial statements based on the fair value of the equity instruments issued and recorded over the requisite service period.

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

	2021	2020
Stock-based compensation expense	$ 4,713	$ 5,846
Income tax benefits	990	1,228
Excess tax expenses on settled share-based employee payments	(909)	(165)

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 eventually vest 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 that 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 that incorporates the probability of meeting the market targets based on historical returns relative to a peer group. The estimated fair value of the CEPS awards was estimated on the date of grant as the share price of Avista Corp. common stock on the date of grant.

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:

	2021	2020
Restricted Shares		
Shares granted during the year	62,594	45,540
Shares vested during the year	34,854	56,203
Unvested shares at end of year	96,127	71,706
Unrecognized compensation expense at end of year (in thousands)	$ 2,215	$ 2,003
TSR Awards		
TSR shares granted during the year	64,910	47,848
TSR shares vested during the year	77,174	71,299
TSR shares earned based on market metrics	58,652	
Unvested TSR shares at end of year	107,854	122,133
Unrecognized compensation expense at end of year (in thousands)	$ 2,653	$ 2,296
CEPS Awards		
CEPS shares granted during the year	64,910	47,848
CEPS shares vested during the year	38,590	35,622
CEPS shares earned based on market metrics	26,627	63,763
Unvested CEPS shares at end of year	107,854	83,464
Unrecognized compensation expense at end of year (in thousands)	$ 1,223	$ 1,090

Outstanding restricted, TSR and CEPS share awards include a dividend component that is 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, 2021 and 2020, the Company had recognized a liability of $1.5 million and $0.8 million, respectively, related to the dividend equivalents payable on the outstanding and unvested share grants.

Cash and Cash Equivalents

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

Allowance for Doubtful Accounts

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

Utility Plant in Service

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

Asset Retirement Obligations (ARO)

The Company records the fair value of a liability for an ARO in the period in which it is incurred. When the liability is initially recorded, the associated costs of the ARO are capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the related capitalized costs are depreciated over the useful life of the related asset. In addition, if there are changes in the estimated timing or estimated costs of the AROs, adjustments are recorded during the period new information becomes available as an increase or decrease to the liability, with the offset recorded to the related long-lived asset. Upon retirement of the asset, the Company either settles the ARO for its recorded amount or recognizes a regulatory asset or liability for the difference, which will be surcharged/refunded to customers through the ratemaking process. The Company records regulatory assets and liabilities for the difference between asset retirement costs currently recovered in rates and AROs recorded since asset retirement costs are recovered through rates charged to customers (see Note 7 for further discussion of the Company's AROs).

Derivative Assets and Liabilities

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

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

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

The Company has multiple master netting agreements with a variety of entities that allow for cross-commodity netting of derivative agreements with the same counterparty (i.e. power derivatives can be netted with natural gas derivatives). In addition, some master netting agreements allow for the netting of commodity derivatives and interest rate swap derivatives for the same counterparty. The Company does not have any 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 swap derivatives and foreign currency exchange derivatives, are reported at estimated fair value on the Balance Sheets. See Note 15 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 that 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), are 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 3 for discussion on decoupling revenue deferrals.

If at some point in the future the Company determines that 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 or discounts paid to repurchase debt are amortized over the remaining life of the original debt that was 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 premiums and discounts 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 any earnings in excess of the specified rate of return on the Company's investment in the licenses for its various hydroelectric projects. Per section 10(d) of the FPA, the Company must maintain these excess earnings in an appropriated retained earnings account until the termination of the licensing agreements or apply them to reduce the net investment in the licenses of the hydroelectric projects at the discretion of the FERC. The Company calculates the earnings in excess of the specified rate of return on an annual basis, usually during the second quarter.

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

	2021	2020
Appropriated retained earnings	$ 51,518	$ 45,453

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, 2021, the Company has not recorded any significant amounts related to unresolved contingencies. See Note 17 for further discussion of the Company's commitments and contingencies.

COVID-19

In 2020, the WUTC, IPUC, and OPUC approved accounting orders that allow the Company to defer certain net COVID-19 related costs and benefits. As such, as of December 31, 2021, the Company has deferred net costs of $1.1 million for all jurisdictions.

The respective regulatory authorities will determine the appropriateness and prudency of any deferred expenses when the Company seeks recovery. See "Regulatory Deferred Charges and Credits".

Equity in Earnings (Losses) of Subsidiaries

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

	2021	2020
Avista Capital	$ 16,645	$ (2,489)
AERC	6,910	7,795
Total equity in earnings of subsidiary companies	$ 23,555	$ 5,307

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2021 up to February 22, 2022, the date that Avista Corp.'s U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through the date of this filing. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

NOTE 2. NEW ACCOUNTING STANDARDS

Accounting Standards Update (ASU) 2018-13 "Fair Value Measurement (Topic 820)"

In August 2018, the FASB issued ASU No. 2018-13, which amends the fair value measurement disclosure requirements of ASC 820. The requirements of this ASU include additional disclosure regarding the range and weighted average used to develop significant unobservable inputs for Level 3 fair value estimates and the elimination of certain other previously required disclosures, such as the narrative description of the valuation process for Level 3 fair value measurements. This ASU became effective on January 1, 2020 and the requirements of this ASU did not have a material impact on the Company's fair value disclosures. See Note 15 for the Company's fair value disclosures.

ASU No. 2018-14 "Compensation - Retirement Benefits - Defined Benefit Plans - General (Subtopic 715-20)"

In August 2018, the FASB issued ASU No. 2018-14, which amends ASC 715 to add, remove and/or clarify certain disclosure requirements related to defined benefit pension and other postretirement plans. The additional disclosure requirements are primarily narrative discussion of significant changes in the benefit obligations and plan assets. The removed disclosures are primarily information about accumulated other comprehensive income expected to be recognized over the next year and the effects of changes associated with assumed health care costs. This ASU became effective for periods ending after December 15, 2020 and the requirements of this ASU did not have a material impact on the Company's disclosures upon adoption.

NOTE 3. REVENUE

ASC 606 defines 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. Given that 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. Given that all revenue recognition criteria are met upon the delivery of energy to customers, revenue is recognized immediately 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,
- current rates,
- meter reading dates,
- actual native load for electricity,
- actual throughput for natural gas, and
- electric line losses and natural gas system losses.

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

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

	2021	2020
Unbilled accounts receivable	$ 71,752	$ 68,545

Non-Derivative Wholesale Contracts

The Company has certain wholesale contracts which are not accounted for as derivatives and, accordingly, are within the scope of ASC 606 and considered revenue from contracts with customers. Revenue is recognized as energy is delivered to the customer or the service is available for specified period of time, consistent with the discussion of rate regulated sales above.

Alternative Revenue Programs (Decoupling)

ASC 606 retained existing GAAP associated with alternative revenue programs, which specified that alternative revenue programs are contracts between an entity and a regulator of utilities, not a contract between an entity and a customer. GAAP requires that an entity present revenue arising from alternative revenue programs separately from revenues arising from contracts with customers on the face of 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 any 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 current period Statements of Income. Any 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 which must be 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 specifically scoped out of ASC 606. As such, these revenues 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 those transactions that are entered into and settled within the same month.

Other Utility Revenue

Other utility revenue includes rent, sales of materials, late fees and other charges that do not represent contracts with customers. This revenue is scoped out of ASC 606, as this revenue does not represent items where a customer is a party that has contracted with the Company to obtain goods or services that are an output of the Company's ordinary activities in exchange for consideration. As such, these revenues are presented separately from revenue from contracts with customers.

Other Considerations for Utility Revenues

Gross Versus Net Presentation

Utility-related taxes collected from customers (primarily state excise taxes and city utility taxes) are taxes that are imposed on Avista Corp. as opposed to being imposed on its 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 that were included in revenue from contracts with customers were as follows for the years ended December 31 (dollars in thousands):

	2021	2020
Utility-related taxes	$ 62,736	$ 59,319

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 does have one capacity agreement where the customer makes payments throughout the year. As of December 31, 2021, the Company estimates it had unsatisfied capacity performance obligations of $17.4 million, which will be recognized as revenue in future periods as the capacity is provided to the customers. These performance obligations are not reflected in the financial statements, as the Company has not received payment for these services.

Disaggregation of Total Operating Revenue

The following table disaggregates total operating revenue by source for the years ended December 31 (dollars in thousands):

	2021	2020
Revenue from contracts with customers	$ 1,244,314	$ 1,168,207
Derivative revenues	247,676	203,099
Alternative revenue programs	(6,635)	(3,814)
Deferrals and amortizations for rate refunds to customers	1,093	4,795
Other utility revenues	9,138	7, 589
Total	1,495,586	1,379,876

Utility Revenue from Contracts with Customers by Type and Service

The following table disaggregates revenue from contracts with customers associated with the Company's electric operations for the years ended December 31 (dollars in thousands):

2021	2020

ELECTRIC OPERATIONS					
Revenue from contracts with customers					
Residential	$ 394,717				$ 377,785
Commercial and governmental	326,173				303,972
Industrial	117,165				113,563
Public street and highway lighting	7,472				7,303
Total retail revenue	845,527				802,624
Transmission	21,005				18,236
Other revenue from contracts with customers	33,870				19,252
Total revenue from contracts with customers	$ 900,402				$ 840,112

The following table disaggregates revenue from contracts with customers associated with the Company's natural gas operations for the years ended December 31 (dollars in thousands):

	2021	2020
NATURAL GAS OPERATIONS		
Revenue from contracts with customers		
Residential	$ 221,405	$ 213,612
Commercial	100,819	94,937
Industrial and interruptible	7,796	7,128
Total retail revenue	330,020	315,677
Transportation	8,547	7,917
Other revenue from contracts with customers	5,345	4,501
Total revenue from contracts with customers	$ 343,912	$ 328,095

NOTE 4. LEASES

ASC 842, outlines a model for entities to use in accounting for leases. The core principle of the model is that an entity should recognize the ROU assets and liabilities that arise 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 arising 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 arising from the lease. 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 any 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 that the Company will exercise that option. Lease expense for lease payments is recognized on a straight-line basis over the lease term. Any 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 Energy. In addition, the State of Montana and Avista Corp. are engaged in litigation regarding lease terms, including how much money, if any, the State of Montana should return to Avista Corp. Amounts recorded for this lease are uncertain and amounts may change in the future depending on the outcome of the ongoing litigation. Any reduction in future lease payments or the return of previously paid amounts to Avista Corp. will be included in the future ratemaking process.

In addition to the lease with the State of Montana, the Company also 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 72 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 any material residual value guarantees or material restrictive covenants.

Avista Corp. does not record leases with a term of 12 months or less in the Balance Sheets. Total short-term lease costs for the year ended December 31, 2021 are immaterial.

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

	2021	2020
Operating lease cost:		
Fixed lease cost	$ 4,970	$ 4,746
Variable lease cost	1,180	1,099
Total operating lease cost	$ 6,150	$ 5,845

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

	2021	2020
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash outflows:		
Operating lease payments	$ 4,805	$ 4,612

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

	December 31, 2021	December 31, 2020
Operating Leases		
Operating lease ROU assets (Utility Plant)	$ 70,133	$ 71,891
Obligations under capital lease - current	$ 4,301	$ 4,249
Obligations under capital lease - noncurrent	66,068	67,716
Total operating lease liabilities	$ 70,369	$ 71,965

Weighted Average Remaining Lease Term		
Operating leases	24.22 years	25.20 years
Weighted Average Discount Rate		
Operating leases	4.28 %	4.28 %

Maturities of lease liabilities (including principal and interest) were as follows as of December 31, 2021 (dollars in thousands):

	Operating Leases
2022	$ 4,820
2023	4,849
2024	4,875
2025	4,882
2026	4,867
Thereafter	91,845
Total lease payments	$ 116,138
Less: imputed interest	(45,769)
Total	$ 70,369

Maturities of lease liabilities (including principal and interest) were as follows as of December 31, 2020 (dollars in thousands):

	Operating Leases
2021	$ 4,779
2022	4,799
2023	4,827
2024	4,852
2025	4,865
Thereafter	96,734
Total lease payments	$ 120,856
Less: imputed interest	(48,891)
Total	$ 71,965

NOTE 5. DERIVATIVES AND RISK MANAGEMENT

Energy Commodity Derivatives

Avista Corp. is exposed to market risks relating to changes in electricity and natural gas commodity prices and certain other fuel prices. Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. Avista Corp. utilizes derivative instruments, such as forwards, futures, swap derivatives and options in order 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, the Company 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. On the basis of 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, 2021 that are 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
2022	129		7,114	61,405	234	452	3,933	31,485
2023			378	23,218			1,360	9,323
2024			228	3,413			1,370	228
2025							1,115	

As of December 31, 2021, there are no expected deliveries of energy commodity derivatives after 2025.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2020 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
2021	1	224	10,353	65,188	17	451	5,448	39,273
2022			450	25,525			1,360	12,030
2023				4,950			1,360	900
2024							1,370	
2025							1,115	

As of December 31, 2020, there were no expected deliveries of energy commodity derivatives after 2025.

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

The electric and natural gas derivative contracts above will be included in either power supply costs or natural gas supply costs during the period they are scheduled to be delivered and will be included in the various deferral and recovery mechanisms (ERM, PCA, and PGAs), or in the general rate case process, and are expected to be collected 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 that Avista Corp. has outstanding as of December 31 (dollars in thousands):

	2021	2020
Number of contracts	25	22
Notional amount (in United States dollars)	$ 8,571	$ 3,860
Notional amount (in Canadian dollars)	10,957	4,949

Interest Rate Swap Derivatives

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

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

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
December 31, 2021	13	140,000	2022
	2	20,000	2023
	1	10,000	2024
December 31, 2020	4	45,000	2021
	11	120,000	2022
	1	10,000	2023

See Note 13 for discussion of the bond purchase agreement and the related settlement of interest rate swaps in connection with the pricing of the bonds in September 2021.

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

Summary of Outstanding Derivative Instruments

The amounts recorded on the Balance Sheets as of December 31, 2021 and December 31, 2020 reflect the offsetting of derivative assets and liabilities where a legal right of offset exists.

The following table presents the fair values and locations of derivative instruments recorded on the Balance Sheets as of December 31, 2021 (in thousands):

	Fair Value			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) on Balance Sheet
Foreign currency exchange derivatives				
Derivative instrument liabilities current	$	$ (19)	$	$ (19)
Interest rate swap derivatives				
Long-term portion of derivative assets	1,149			1,149
Derivative instrument liabilities current	1,170	(25,196)		(24,026)
Long-term portion of derivative liabilities		(78)		(78)
Energy commodity derivatives				
Derivative instrument assets current	1,506	(107)		1,399
Long-term portion of derivative assets	6,844	(5,335)		1,509
Derivative instrument liabilities current	25,771	(39,616)	9,089	(4,756)
Long-term portion of derivative liabilities	141	(4,589)		(4,448)
Total derivative instruments recorded on the balance sheet	$ 36,581	$ (74,940)	$ 9,089	$ (29,270)

The following table presents the fair values and locations of derivative instruments recorded on the Balance Sheets as of December 31, 2020 (in thousands):

	Fair Value			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) on Balance Sheet
Foreign currency exchange derivatives				
Derivative instrument assets current	$ 30	$	$	$ 30
Interest rate swap derivatives				
Derivative instrument liabilities current		(19,575)	8,050	(11,525)
Long-term portion of derivative liabilities	952	(32,190)		(31,238)
Energy commodity derivatives				
Derivative instrument assets current	9,203	(8,306)		897
Long-term portion of derivative assets	1,755	(1,159)		596
Derivative instrument liabilities current	11,037	(14,007)	487	(2,483)
Long-term portion of derivative liabilities	1,725	(8,043)	129	(6,189)
Total derivative instruments recorded on the balance sheet	$ 24,702	$ (83,280)	$ 8,666	$ (49,912)

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 a downgrade in Avista Corp.'s credit ratings or changes in market prices, additional collateral may be required. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against Avista Corp.'s credit facilities and cash. Avista Corp. actively monitors the exposure to possible collateral calls and takes steps to mitigate capital requirements.

The following table presents Avista Corp.'s collateral outstanding related to its derivative instruments as of December 31 (in thousands):

	2021	2020
Energy commodity derivatives		
Cash collateral posted	$ 30,567	$ 4,953
Letters of credit outstanding	34,000	23,500
Balance sheet offsetting (cash collateral against net derivative positions)	9,089	616
Interest rate swap derivatives		
Cash collateral posted (offset by net derivative positions)		8,050

There were no letters of credit outstanding related to interest rate swap derivatives as of December 31, 2021 and December 31, 2020.

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

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

	2021	2020
Interest rate swap derivatives		
Liabilities with credit-risk-related contingent features	$ 25,274	$ 50,813
Additional collateral to post	25,274	42,763

NOTE 6. JOINTLY OWNED ELECTRIC FACILITIES

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

	2021	2020
Utility plant in service	$ 395,028	$ 391,922
Accumulated depreciation	(302,220)	(284,282)

See Note 7 for further discussion of AROs.

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

NOTE 7. ASSET RETIREMENT OBLIGATIONS

The Company has recorded liabilities for future AROs to:

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

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

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

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

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

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

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

	2021	2020
Asset retirement obligation at beginning of year	$ 17,194	$ 20,338
Liabilities incurred	825	(2,315)
Liabilities settled	(1,541)	(1,645)
Accretion expense	664	816
Asset retirement obligation at end of year	$ 17,142	$ 17,194

NOTE 8. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The pension and other postretirement benefit plans described below only relate to Avista Corp. AEL&P (not discussed below) participates in a defined contribution multiemployer plan for its union workers and a defined contribution money purchase pension plan for its nonunion workers. None of the subsidiary retirement plans, individually or in the aggregate, are significant to Avista Corp.

Avista Corp.

The Company has a defined benefit pension plan covering the majority of all regular full-time employees at Avista Corp. that were hired prior to January 1, 2014. 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 participate in a defined contribution 401(k) plan in lieu of a defined benefit pension plan. Union employees hired on or after January 1, 2014 are still covered under the defined benefit pension plan. The Company's funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. The Company contributed $42.0 million in cash to the pension plan in 2021, and $22.0 million in 2020. The Company expects to contribute $42.0 million in cash to the pension plan in 2022.

The Company also has a SERP that provides additional pension benefits to certain executive officers and certain key employees of the Company. The SERP is intended to provide 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 that benefit payments under the pension plan and the SERP will total (dollars in thousands):

	2022	2023	2024	2025	2026	Total 2027-2031
Expected benefit payments	$ 43,282	$ 43,218	$ 43,675	$ 44,319	$ 43,810	$ 228,585

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

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

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

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

	2022	2023	2024	2025	2026	Total 2027-2031
Expected benefit payments	$ 6,960	$ 7,140	$ 7,291	$ 7,453	$ 7,560	$ 39,646

The Company expects to contribute $7.2 million to other postretirement benefit plans in 2022, representing expected benefit payments to be paid during the year excluding the Medicare Part D subsidy. The Company uses a December 31 measurement date for its pension and other postretirement benefit plans.

The following table sets forth the pension and other postretirement benefit plan disclosures as of December 31, 2021 and 2020 and the components of net periodic benefit costs for the years ended December 31, 2021 and 2020(dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2021	2020	2021	2020
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 826,915	$ 742,382	$ 161,233	$ 159,296
Service cost	25,306	22,392	4,114	3,902
Interest cost	26,160	27,853	5,139	6,042
Actuarial (gain)/loss	(13,997)	74,688	2,808	(2,589)
Benefits paid	(65,342)	(40,400)	(5,696)	(5,418)
Benefit obligation as of end of year	$ 799,042	$ 826,915	$ 167,598	$ 161,233
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 722,024	$ 642,063	$ 52,173	$ 44,853
Actual return on plan assets	50,370	96,591	7,371	7,320
Employer contributions	42,000	22,000		
Benefits paid	(63,431)	(38,630)		
Fair value of plan assets as of end of year	$ 750,963	$ 722,024	$ 59,544	$ 52,173
Funded status	$ (48,079)	$ (104,891)	$ (108,054)	$ (109,060)
Amounts recognized in the Balance Sheets:				
Current liabilities	$ (1,951)	$ (1,943)	$ (684)	$ (669)
Non-current liabilities	(46,128)	(102,948)	(107,370)	(108,391)
Net amount recognized	$ (48,079)	$ (104,891)	$ (108,054)	$ (109,060)
Accumulated pension benefit obligation	$ 685,493	$ 710,023		
Accumulated postretirement benefit obligation:				
For retirees			$ 78,347	$ 75,876
For fully eligible employees			$ 32,144	$ 32,097
For other participants			$ 57,107	$ 53,260
Included in accumulated other comprehensive loss (income) (net of tax):				
Unrecognized prior service cost (credit)	$ 1,699	$ 1,902	$ (2,741)	$ (3,570)
Unrecognized net actuarial loss	94,109	119,318	48,872	53,737
Total	95,808	121,220	46,131	50,167
Less regulatory asset	(85,550)	(108,301)	(45,350)	(48,708)
Accumulated other comprehensive loss for unfunded benefit obligation for pensions and other postretirement benefit plans	$ 10,258	$ 12,919	$ 781	$ 1,459

	Pension Benefits		Other Post-retirement Benefits	
	2021	2020	2021	2020
Weighted-average assumptions as of December 31:				
Discount rate for benefit obligation	3.39%	3.25%	3.40%	3.27%
Discount rate for annual expense	3.25%	3.85%	3.27%	3.89%
Expected long-term return on plan assets	5.40%	5.50%	4.60%	5.30%
Rate of compensation increase	4.66%	4.74%		
Medical cost trend pre-age 65 - initial			6.00%	6.25%
Medical cost trend pre-age 65 - ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2026	2026
Medical cost trend post-age 65 - initial			6.00%	6.25%
Medical cost trend post-age 65 - ultimate			5.00%	5.00%
Ultimate medical cost trend year post-age 65			2026	2026

		Other Post-retirement Benefits			
	2021	2020		2021	2020
Components of net periodic benefit cost:					
Service cost (a)	$ 25,306	$ 22,392		$ 4,114	$ 3,902
Interest cost	26,160	27,853		5,139	6,042
Expected return on plan assets	(39,088)	(34,886)		(2,400)	(2,377)
Amortization of prior service cost (credit)	257	257		(921)	(958)
Net loss recognition	6,645	6,717		3,865	4,871
Net periodic benefit cost	$ 19,280	$ 22,333		$ 9,797	$ 11,480

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

Plan Assets

The Finance Committee of the Company's 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, trusts and partnerships that hold marketable debt and equity securities, real estate, and absolute return. 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 also investment ranges for each asset class. The target investment allocation percentages are typically the midpoint of the established range. The target investment allocation percentages by asset classes are indicated in the table below:

	2021	2020
Equity securities	55%	35%
Debt securities	40%	49%

Real estate	5%	7%
Absolute return	0%	9%

The target investment allocation percentages were revised in the first quarter of 2021 and the pension plan assets were reinvested to move toward the new target investment allocation percentages. The target asset allocation percentages were modified to better align the asset allocations with the funded status of the pension plan.

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 that are comparable in coupon, rating, maturity and industry).

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

The Company's investments in common/collective trusts have redemption limitations that permit quarterly redemptions following notice requirements of 45 to 60 days. Most of the Company's investments in closely held investments and partnership interests have redemption limitations that range from bi-monthly to semi-annually following redemption notice requirements of 60 to 90 days. One investment in a partnership has a lock-up for redemption currently expiring in 2022 and is subject to extension.

The following table discloses by level within the fair value hierarchy (see Note 15 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2021 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$	$ 6,259	$	$ 6,259
Fixed income securities:				
U.S. government issues		19,310		19,310
Corporate issues		233,496		233,496
International issues		34,270		34,270
Municipal issues		18,558		18,558
Mutual funds:				
U.S. equity securities	236,552			236,552
International equity securities	112,873			112,873
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts:				
Real estate				31,040
Partnership/closely held investments:				
Absolute return (1)				363
International equity securities				50,427
Real estate				7,815
Total	$ 349,425	$ 311,893	$	$ 750,963

The following table discloses by level within the fair value hierarchy (see Note 15 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2020 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$	$ 3,309	$	$ 3,309
Fixed income securities:				
U.S. government issues		10,990		10,990
Corporate issues		279,857		279,857
International issues		39,634		39,634
Municipal issues		22,431		22,431
Mutual funds:				
U.S. equity securities	146,375			146,375
International equity securities	96,311			96,311
Absolute return (1)	11,640			11,640
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts:				
Real estate				29,532
Partnership/closely held investments:				
Absolute return (1)				47,188
International equity securities				26,760
Real estate				7,997
Total	$ 254,326	$ 356,221	$	$ 722,024

(1)This category invests in multiple strategies to diversify risk and reduce volatility. The strategies include: (a) event driven, relative value, convertible, and fixed income arbitrage, (b) distressed investments, (c) long/short equity and fixed income and (d) market neutral strategies.

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 will determine fair value based upon other inputs (including valuations of securities that are comparable in coupon, rating, maturity and industry). The target asset allocation was 60 percent equity securities and 40 percent debt securities in both 2021 and 2020.

The fair value of other postretirement plan assets was determined as of December 31, 2021 and 2020.

The following table discloses by level within the fair value hierarchy (see Note 15 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2021 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Balanced index mutual fund (1)	$ 59,545	$	$	$ 59,545

The following table discloses by level within the fair value hierarchy (see Note 15 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2020 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Balanced index mutual fund (1)	$ 52,173	$	$	$ 52,173

(1)The balanced index fund for 2021 and 2020 is a single mutual fund that includes a percentage of U.S. equity and fixed income securities and International equity and fixed income securities.

401(k) Plans and Executive Deferral Plan

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

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

	2021	2020
Employer 401(k) matching contributions	$ 11,671	$ 11,742

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 thousands):

	2021	2020
Deferred compensation assets and liabilities	$ 9,513	$ 9,174

NOTE 9. ACCOUNTING FOR INCOME TAXES

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

As of December 31, 2021, the Company had $17.1 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 $7.5 million of the state tax credits. As such, the Company has recorded a valuation allowance of $9.6 million against the state tax credit carryforwards and reflected the net amount of $7.5 million as an asset as of December 31, 2021. State tax credits expire from 2022 to 2035.

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 2017 are open for an IRS tax examination.

The Company also 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.

The Idaho State Tax Commission is currently reviewing tax years 2014 through 2017. All tax years after 2017 are open for examination in Idaho, Oregon, Montana and Alaska.

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

NOTE 10. ENERGY PURCHASE CONTRACTS

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

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

	2021	2020
Utility power resources	$ 431,199	$ 324,297

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

	2022	2023	2024	2025	2026	Thereafter	Total
Power resources	$ 198,052	$ 187,552	$ 200,693	$ 193,877	$ 184,230	$ 1,888,038	$ 2,852,442
Natural gas resources	87,228	66,508	42,581	36,423	32,094	382,981	647,815
Total	$ 285,280	$ 254,060	$ 243,274	$ 230,300	$ 216,324	$ 2,271,019	$ 3,500,257

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. As a result, 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 above future contractual commitments for power resources include fixed contractual amounts related to the Company's contracts with certain Public Utility Districts (PUD) to purchase portions of the output of certain generating facilities. Although Avista Corp. has no investment in the PUD generating facilities, the fixed contracts obligate Avista Corp. to pay certain minimum amounts whether or not the facilities are operating. The cost of power obtained under the contracts, including payments made when a facility is not operating, is included in utility resource costs in the Statements of Income. The contractual amounts included above consist of Avista Corp.'s share of existing debt service cost and its proportionate share of the variable operating expenses of these projects. The minimum amounts payable under these contracts are based in part on the proportionate share of the debt service requirements of the PUD's revenue bonds for which the Company is indirectly responsible. The Company's total future debt service obligation associated with the revenue bonds outstanding at December 31, 2021 (principal and interest) was $278.3 million.

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

	2022	2023	2024	2025	2026	Thereafter	Total
Contractual obligations	$ 28,912	$ 29,680	$ 30,471	$ 31,287	$ 32,127	$ 212,852	$ 365,329

NOTE 11. NOTES PAYABLE

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million. In June 2021, the Company entered into an amendment to its committed line of credit that extends the expiration date to June 2026, with the option to extend 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.

The committed line of credit agreement contains customary covenants and default provisions. The credit agreement has a covenant which does not permit the ratio of "total debt" to "total capitalization" of Avista Corp. to be greater than 65 percent at any time. As of December 31, 2021, the Company was in compliance with this covenant.

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

	2021	2020
Balance outstanding at end of period	$ 284,000	$ 102,000
Letters of credit outstanding at end of period	$ 34,000	$ 27,618
Average interest rate at end of period	1.11%	1.22%

As of December 31, 2021 and 2020, the borrowings outstanding under Avista Corp.'s committed line of credit were classified as short-term borrowings on the Balance Sheets.

NOTE 12. CREDIT AGREEMENT

In April 2020, the Company entered into a Credit Agreement with various financial institutions, in the amount of $100 million. The Company borrowed the entire $100 million available under this agreement in April 2020 and repaid the outstanding balance in April 2021.

NOTE 13. BONDS

The following details bonds outstanding as of December 31 (dollars in thousands):

Maturity Year	Description	Interest Rate	2021	2020
Avista Corp. Secured Long-Term Debt				
2022	First Mortgage Bonds	5.13%	250,000	250,000
2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (1)	(1)	66,700	66,700
2034	Secured Pollution Control Bonds (1)	(1)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
2040	First Mortgage Bonds	5.55%	35,000	35,000
2041	First Mortgage Bonds	4.45%	85,000	85,000
2044	First Mortgage Bonds	4.11%	60,000	60,000

2045	First Mortgage Bonds	4.37%	100,000	100,000
2047	First Mortgage Bonds	4.23%	80,000	80,000
2047	First Mortgage Bonds	3.91%	90,000	90,000
2048	First Mortgage Bonds	4.35%	375,000	375,000
2049	First Mortgage Bonds	3.43%	180,000	180,000
2050	First Mortgage Bonds	3.07%	165,000	165,000
2051	First Mortgage Bonds	3.54%	175,000	175,000
2051	First Mortgage Bonds (2)	2.90%	140,000	
	Total Avista Corp. secured long-term bonds		2,157,200	2,017,200
	Secured Pollution Control Bonds held by Avista Corporation (1)		(83,700)	(83,700)
	Total long-term bonds		$ 2,073,500	$ 1,933,500

(1)In December 2010, $66.7 million and $17.0 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) due in 2032 and 2034, respectively, which had been held by Avista Corp. since 2008 and 2009, respectively, were refunded by new variable rate bond issues (Series 2010A and Series 2010B). The new bonds were not offered to the public and were purchased by Avista Corp. due to market conditions. The Company expects that at a later date, subject to market conditions, these bonds may be remarketed to unaffiliated investors. So long as Avista Corp. is the holder of these bonds, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Balance Sheets.

(2)In September 2021, the Company issued and sold $70.0 million of 2.90 percent first mortgage bonds due in 2051 pursuant to a bond purchase agreement with institutional investors in the private placement market. In December 2021, the Company issued and sold the remaining $70.0 million of bonds pursuant to the same agreement. The total net proceeds from the sale of the bonds were used to repay a portion of the outstanding balance under Avista Corp.'s $400.0 million committed line of credit. In connection with the pricing of the first mortgage bonds in September 2021, the Company cash settled four interest rate swap derivatives (notional aggregate amount of $45.0 million) and paid a net amount of $17.2 million. See Note 7 for a discussion of interest rate swap derivatives.

The following table details future long-term debt maturities including long-term debt to affiliated trusts (see Note 14) (dollars in thousands):

	2022	2023	2024	2025	2026	Thereafter	Total
Debt maturities	$ 250,000	$ 13,500	$	$	$	$ 1,810,000	$ 2,073,500

Substantially all of Avista Corp.'s owned properties are subject to the lien of iyd mortgage indenture. Under the Mortgage and Deed of Trust (Mortgage) securing its first mortgage bonds (including secured medium-term notes), Avista Corp.'s may each 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 (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 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 the 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, 2021, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.8 billion in an aggregate principal amount of additional first mortgage bonds at an assumed interest rate of 8 percent.

NOTE 14. ADVANCES FROM ASSOCIATED COMPANIES

In 1997, the Company issued Floating Rate Junior Subordinated Deferrable Interest Debentures, Series B, with a principal amount of $51.5 million to Avista Capital II, an affiliated business trust formed by the Company. Avista Capital II issued $50.0 million of Preferred Trust Securities with a floating distribution rate of LIBOR plus 0.875 percent, calculated and reset quarterly.

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

	2021	2020
Low distribution rate	0.99%	1.10%
High distribution rate	1.10%	2.79%
Distribution rate at the end of the year	1.05%	1.10%

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

The Company owns 100 percent of Avista Capital II and has solely and unconditionally guaranteed the payment of distributions on, and redemption price and liquidation amount for, the Preferred Trust Securities to the extent that 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 15. FAIR VALUE

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

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

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

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

Level 2 - Pricing inputs are other than quoted prices in active markets included in Level 1, but which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are 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 that are generally unobservable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

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

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

	2021		2020	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 963,500	$ 1,157,651	$ 963,500	$ 1,189,824
Long-term debt (Level 3)	1,110,000	1,258,674	1,970,000	1,125,618
Long-term debt to affiliated trusts (Level 3)	51,547	43,299	51,547	43,815

These estimates of fair value of long-term debt and long-term debt to affiliated trusts were primarily based on available market information, which generally consists of estimated market prices from third party brokers for debt with similar risk and terms. The price ranges obtained from the third party brokers consisted of par values of 84.0 to 140.27, where a par value of 100.00 represents the carrying value recorded on the Balance Sheets. Level 2 long-term debt represents publicly issued bonds with quoted market prices; however, due to their limited trading activity, they are classified as Level 2 because brokers must generate quotes and make estimates using comparable debt with similar risk and terms if there is no trading activity near a period end. Level 3 long-term debt consists of private placement bonds and debt to affiliated trusts, which typically have no secondary trading activity. Fair values in Level 3 are estimated based on market prices from third party brokers using secondary market quotes for debt with similar risk and terms to generate quotes for Avista Corp. bonds.

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Balance Sheets as of December 31, 2021 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2021					
Assets:					
Energy commodity derivatives	$	$ 34,119	$	$ (31,211)	$ 2,908
Level 3 energy commodity derivatives:					
Natural gas exchange agreements			143	(143)	
Interest rate swap derivatives		2,319		(1,170)	1,149
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities	1,809				1,809
Equity securities	7,594				7,594
Total	$ 9,403	$ 36,438	$ 143	$ (32,524)	$ 13,460
Liabilities:					
Energy commodity derivatives	$	$ 41,733	$	$ (40,300)	$ 1,433
Level 3 energy commodity derivatives:					
Natural gas exchange agreement			7,914	(143)	7,771
Foreign currency exchange derivatives		19			19
Interest rate swap derivatives		25,274		(1,170)	24,104
Total	$	$ 67,026	$ 7,914	$ (41,613)	$ 33,327

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, 2020 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2020					
Assets:					
Energy commodity derivatives	$	$ 23,645	$	$ (22,152)	$ 1,493
Level 3 energy commodity derivatives:					
Natural gas exchange agreement			75	(75)	
Foreign currency exchange derivatives		30			30
Interest rate swap derivatives		952		(952)	
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities	2,471				2,471
Equity securities	6,228				6,228
Total	$ 8,699	$ 24,627	$ 75	$ (23,179)	$ 10,222
Liabilities:					
Energy commodity derivatives	$	$ 23,030	$	$ (22,768)	$ 262
Level 3 energy commodity derivatives:					
Natural gas exchange agreement			8,485	(75)	8,410
Interest rate swap derivatives		51,765		(9,002)	42,763
Total	$	$ 74,795	$ 8,485	$ (31,845)	$ 51,435

(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 any payables and receivables for cash collateral held or placed with these same counterparties.

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

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

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

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

Deferred compensation assets and liabilities represent funds held by the Company in a Rabbi Trust for an executive deferral plan. These funds consist of actively traded equity and bond funds with quoted prices in active markets. The balance disclosed in the table above excludes cash and cash equivalents of $0.1 million as of December 31, 2021 and $0.5 million as of December 31, 2020.

Level 3 Fair Value

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

The following table presents the quantitative information which was used to estimate the fair values of the Level 3 assets and liabilities above as of December 31, 2021 (dollars in thousands):

	Fair Value (Net) at December 31, 2021	Valuation Technique	Unobservable Input	Range
Natural gas exchange	(7,771)	Internally derived weighted average cost of gas	Forward purchase prices	$2.35 - $4.08/mmBTU $2.96 Weighted Average
			Forward sales prices	$2.38 - $9.50/mmBTU $4.51 Weighted Average
			Purchase volumes	130,000 - 310,000 mmBTUs
			Sales volumes	25,000 - 310,000 mmBTUs

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

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

	Natural Gas Exchange Agreement		Power Exchange Agreement		Total	
Year ended December 31, 2021:						
Balance as of January 1, 2021	$	(8,410)	$	—	$	(8,410)
Total gains or (losses) (realized/unrealized):						
Included in regulatory assets (1)		4,292		—		4,292
Settlements		(3,653)		—		(3,653)
Ending balance as of December 31, 2021 (2)	$	(7,771)	$	—	$	(7,771)
Year ended December 31, 2020:						
Balance as of January 1, 2020	$	(2,976)	$	—	$	(2,976)
Total gains or (losses) (realized/unrealized):						
Included in regulatory assets (1)		(4,311)		—		(4,311)
Settlements		(1,123)		—		(1,123)
Ending balance as of December 31, 2020 (2)	$	(8,410)	$	—	$	(8,410)

(1)All gains and losses are included in other regulatory assets and liabilities. There were no gains and losses included in either net income or other comprehensive income during any of the periods presented in the table above.

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

NOTE 16. COMMON STOCK

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

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

The requirements of the OPUC approval of the AERC acquisition are the most restrictive. Under the OPUC restriction, the amount available for dividends at December 31, 2021 was $322.3 million.

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2021 and 2020.

Common Stock Issuances

The Company issued common stock in 2021 for total net proceeds of $90.0 million. Most of these issuances came through the Company's sales agency agreements under which the sales agents may offer and sell new shares of common stock from time to time. The Company has board and regulatory authority to issue a maximum of 4.3 million shares under these agreements, of which 2.1 million remain unissued as of December 31, 2021. In 2021, 2.2 million shares were issued under these agreements resulting in total net proceeds of $88.5 million.

NOTE 17. 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 intends to vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the ultimate outcome of any particular matter because litigation and other contested proceedings are inherently subject to numerous uncertainties. For matters that affect Avista Corp.'s operations, the Company intends to seek, to the extent appropriate, recovery of incurred costs through the ratemaking process.

Collective Bargaining Agreements

The Company's collective bargaining agreement with the IBEW represents approximately 40 percent of all of Avista Corp.'s employees. The Company's largest represented group, representing approximately 90 percent of Avista Corp.'s bargaining unit employees in Washington and Idaho, were covered under a three-year agreement which expired in March 2021. In March 2022, a new four-year collective bargaining agreement was reached with the IBEW. The new agreement is retroactive to March 2021 and expires in March 2025. The new agreement's impact on the financial statements was consistent with management's expectations.

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 up to $4.4 million for fire suppression and investigation costs and related expenses incurred in connection with a wildfire that occurred in Ferry County, Washington in August 2018. Specifically, the complaint alleges that the fire, which became known as the "Boyds Fire," was caused by a dead ponderosa pine tree falling into an overhead distribution line, and that Avista Corp. was negligent in failing to identify and remove the tree before it came into contact with the line. Avista Corp. disputes that the tree in question was the cause of the fire and that it was negligent in failing to identify and remove it. Additional lawsuits have subsequently been filed by private landowners seeking property damages, and holders of insurance subrogation claims seeking recovery of insurance proceeds paid.

The lawsuits were filed in the Superior Court of Ferry County, Washington. The Company continues to vigorously defend itself in the litigation. However, the Company cannot predict the outcome of these matters.

Road 11 Fire

On April 13, 2022, Avista Corp. received a notice of claim from a property owner seeking damages in connection with a fire that occurred in Douglas County, Washington, just west of State Route 172, on July 11, 2020. The fire, which was designated as the "Road 11 Fire," occurred in the vicinity of Avista Corp.'s Chelan-Stratford 115kv line, resulting in damage to three overhead transmission structures. The fire occurred during a high wind event and grew to 10,000 acres before being contained. The property owner's notice of claims states that they are seeking damages of $5 million. The Company disputes that it is liable for the fire, and will vigorously defend itself in any legal action that might be commenced in connection with the same.

Labor Day Windstorm

General

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

The Company has become aware of instances where, during the course of the storm, otherwise healthy trees and limbs, located in areas outside its maintenance right-of-way, broke under the extraordinary wind conditions and caused damage to its energy delivery system at or near what is believed to be the potential area of origin of a wildfire. Those instances include what has been referred to as: the Babb Road fire (near Malden and Pine City, Washington); the Christensen Road fire (near Airway Heights, Washington); and the Mile Marker 49 fire (near Orofino, Idaho). These wildfires covered, in total, approximately 22,000 acres. The Company currently estimates approximately 230 residential, commercial and other structures were impacted. With respect to the Christensen Road Fire and the Mile Marker 49 Fire, the Company's investigation determined that the primary cause of the fires was extreme high winds. To date, the Company has not found any evidence that the fires were caused by any deficiencies in its equipment, maintenance activities or vegetation management practices. See further discussion below regarding the Babb Road Fire.

In addition to the instances identified above, the Company is aware of a 5-acre fire that occurred in Colfax, Washington, which damaged several residential structures. The Company's investigation determined that the Company's facilities were not involved in the ignition of this fire.

The Company's investigation has found no evidence of negligence with respect to any of the fires, and the Company intends to vigorously defend any claims for damages that may be asserted against it with respect to the wildfires arising out of the extreme wind event.

Babb Road Fire

On May 14, 2021 the Company learned that the Washington Department of Natural Resources (DNR) had completed its investigation and issued a report on the Babb Road Fire. The Babb Road fire covered approximately 15,000 acres and destroyed approximately 220 structures. There are no reports of personal injury or death resulting from the fire.

The DNR report concluded, among other things, that

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

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

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

Five lawsuits seeking unspecified damages have been filed in connection with the Babb Road fire. These include a negligence action filed in the Superior Court of Spokane County, Washington on behalf approximately 44 individual plaintiffs; negligence-based subrogation actions filed in the Superior Courts of Spokane and Whitman County, Washington on behalf of 23 insurance carriers; and a class action lawsuit filed in the Superior Court of Spokane County Washington alleging negligence, private nuisance, trespass and inverse condemnation. The Company intends to vigorously defend itself in all such legal proceedings.

Colstrip

Colstrip Owners Arbitration and Litigation

Colstrip Units 3 & 4 are jointly owned by the Company, Puget Sound Energy (PSE), Pacificorp, Portland General Electric (PGE) (collectively, the "Western Co-Owners"), as well as NorthWestern and Talen, and are operated pursuant to an Ownership and Operating Agreement dated May 6, 1981, as amended (O&O Agreement). Avista Corp. is a 15 percent owner in Units 3 & 4. No single owner owns more than 30 percent of either generating unit.

The Washington Clean Energy Transformation Act (CETA) imposes deadlines by which coal-fired resources, such as Colstrip, must be excluded from the rate base of Washington utilities and by which electricity from such resources may no longer be delivered to Washington retail customers. The co-owners of Colstrip have differing needs for the generating capacity of these units. Accordingly, business disagreements have arisen among the co-owners, including, but not limited to, disagreements as to the shut-down date or dates of these units. These business disagreements, in turn, have led to disagreements as to the interpretation of the O&O Agreement, including, but not limited to, what percentage voting requirement under the O&O Agreement (55 percent vs. 100 percent) is needed to remove one or more of the Colstrip units from service or to make a determination that the project can no longer be operated consistent with prudent utility practice or the requirements of governmental agencies having jurisdiction. These disagreements are the subject of pending litigation in Montana Federal District Court in which the Western Co-Owners are plaintiffs and NorthWestern and Talen are defendants, as well as in the Montana District for Yellowstone County, in which Talen is the plaintiff and the Western Co-Owners and NorthWestern are defendants.

In addition, there are legal proceedings pending in Montana Federal District Court with respect to the validity and constitutionality of changes to Montana law enacted in 2021 after the foregoing disputes arose. The Western Co-Owners are plaintiffs in those proceedings and NorthWestern and Talen are defendants. The changes to Montana law at issue purport to (a) dictate the location of any arbitration under the O&O Agreement, overriding the express provisions of that agreement; and (b) define actions relating to closing or not operating Colstrip as violations of Montana's Consumer Protection Act. These legal proceedings remain pending.

The Company is not able to predict the outcome, nor an amount or range of potential impact in the event of an outcome that is adverse to the Company's interests. However, the Company will continue to vigorously defend and protect its interests (and those of its stakeholders) in all legal proceedings relating to Colstrip.

Burnett et al. v. Talen et al.

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

Westmoreland Mine Permits

Two lawsuits have been commenced by the Montana Environmental Information Center, challenging certain permits relating to the operation of the Westmoreland Rosebud Mine, which provides coal to Colstrip. The first, filed in the Montana District Court for Rosebud County, challenges the approval, by the Montana Board of Environmental Review, of a permit for mining what is designated as the "AM4" area of the mine, alleging procedural flaws in the approval process and substantive errors in its assessment of environmental impacts. On January 28, 2022, the Montana District Court for Rosebud County issued an order vacating the AM4 permit but deferring the annulment until April 1, 2022.

The second proceeding, filed in the Montana Federal District Court, challenged the Office of Surface Mining Reclamation and Enforcement's decision approving Westmoreland's expansion of the mine into what is designated as "Area F" on the grounds that it violated the National Environmental Protection Act and the Endangered Species Act. On February 11, 2022, a Magistrate Judge issued findings and recommended that approval decision be vacated but that the annulment be delayed for 365 days from the date of a final order.

Avista Corp. is not a party to either of these proceedings. Avista Corp. is continuing to monitor the progress of both lawsuits and assess the impact, if any, of the proceedings on Westmoreland's ability to meet its contractual coal supply obligations.

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

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

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

Rathdrum, Idaho Natural Gas Incident

In October 2021, there was an incident in Rathdrum, Idaho involving the Company's natural gas infrastructure. The incident occurred after a third party damaged those facilities during the course of excavation work. The incident resulted in a fire which destroyed one residence and resulted in minor injuries to the occupants. At this time, the Company is unable to predict the likelihood of a claim arising out of the matter, nor an amount or range of a potential loss, if any, in the event of such a claim.

Other Contingencies

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes that any ultimate liability arising from these actions will not have a material impact on its financial condition, results of operations or cash flows. It is possible that 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 State of Montana is examining the status of all water right claims within state boundaries through a general adjudication. Claims within the Clark Fork River basin could adversely affect the energy production of the Company's Cabinet Gorge and Noxon Rapids hydroelectric facilities. The state of Idaho has initiated adjudication in northern Idaho, which will ultimately include the lower Clark Fork River, the Spokane River and the Coeur d'Alene basin. The Company is and will continue to be a participant in these and any other relevant 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 18. 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 and defer these differences (over the $4.0 million deadband and sharing bands) for future surcharge or rebate to customers. For 2021, the Company recognized a pre-tax expense of $7.7 million under the ERM in Washington compared to a benefit of $6.2 million for 2020. Total net deferred power costs under the ERM were a liability of $11.9 million as of December 31, 2021 and a liability of $37.9 million as of December 31, 2020. These deferred power cost balances 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. As the cumulative rebate balance exceeded $30 million, the Company's 2019 filing contained a proposed rate refund. The ERM proceeding was considered with the Company's 2019 general rate case proceeding and a refund was approved and is being returned to customers over a two-year period that began on April 1, 2020. 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.

Avista Corp. has a PCA mechanism in Idaho that allows it to modify 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 an asset of $10.8 million as of December 31, 2021 and $2.5 million as of December 31, 2020. 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. Total net deferred natural gas costs were an asset of $21.0 million as of December 31, 2021 and $1.4 million as of December 31, 2020. Asset balances represent amounts due from customers and liabilities represent amounts due to customers.

Decoupling and Earnings Sharing Mechanisms

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

Washington Decoupling and Earnings Sharing

In Washington, the WUTC approved the Company's decoupling mechanisms for electric and natural gas for a five-year period beginning January 1, 2015. In 2019, the WUTC approved an extension of the mechanisms for an additional five-year term through March 31, 2025, with one modification in that new customers added after any test period would not be decoupled until included in a future test period.

Electric and natural gas decoupling surcharge rate adjustments to customers are limited to a 3 percent increase on an annual basis, with any remaining surcharge balance carried forward for recovery in a future period. There is no limit on the level of rebate rate adjustments.

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. If the Company earns more than its authorized rate of return (ROR) in Washington, 50 percent of excess earnings are rebated to customers through adjustments to decoupling surcharge or rebate balances. See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

The Company has proposed to modify this earnings test in its 2022 general rate case, so that if the Company earns more than 0.5 percent higher than the ROR authorized by the WUTC in the multi-year rate plan, the Company would defer these excess revenues and later return them to customers.

Idaho FCA and Earnings Sharing Mechanisms

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

Oregon Decoupling Mechanism

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

Cumulative Decoupling and Earnings Sharing Mechanism Balances

As of December 31, 2021 and December 31, 2020, the Company had the following cumulative balances outstanding related to decoupling and earnings sharing mechanisms in its various jurisdictions (dollars in thousands):

	December 31, 2021		December 31, 2020	
Washington				
Decoupling surcharge	$	13,522	$	21,340
Idaho				
Decoupling (rebate) surcharge	$	(1,450)	$	1,202
Provision for earnings sharing rebate		(686)		(686)
Oregon				
Decoupling surcharge (rebate)	$	3,152	$	(1,262)

There were no earnings sharing rebates associated with Washington and Oregon as of December 31, 2021 and December 31, 2020.

19. SUPPLEMENTAL CASH FLOW INFORMATION

Supplemental cash flow information consisted of the following items for the years ended December 31 (dollars in thousands):

	2021		2020	
Cash paid for interest	$	92,143	$	91,188
Cash paid for income taxes		1,476		701
Cash received for income tax refunds		(22,330)		(984)

NOTE 20. SUBSEQUENT EVENTS

The Company has evaluated its subsequent events and noted no subsequent events have occurred.

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Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization and Depletion

Line No.	Item (a)	Total Company For the Current Quarter/Year (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Common (f)
1	UTILITY PLANT					
2	In Service					
3	Plant in Service (Classified)	6,983,399,354	4,775,009,486	1,487,315,761		721,074,107
4	Property Under Capital Leases	70,132,733				[(a)]70,132,733
5	Plant Purchased or Sold					
6	Completed Construction not Classified					
7	Experimental Plant Unclassified					
8	TOTAL Utility Plant (Total of lines 3 thru 7)	7,053,532,087	4,775,009,486	1,487,315,761		791,206,840
9	Leased to Others					
10	Held for Future Use	18,875,451	17,420,225	190,585		1,264,641
11	Construction Work in Progress	196,305,682	170,124,544	6,889,479		19,291,659
12	Acquisition Adjustments	268,032	268,032			
13	TOTAL Utility Plant (Total of lines 8 thru 12)	7,268,981,252	4,962,822,287	1,494,395,825		811,763,140
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	2,465,058,317	1,740,009,100	447,762,096		277,287,121
15	Net Utility Plant (Total of lines 13 and 14)	4,803,922,935	3,222,813,187	1,046,633,729		534,476,019
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION					
17	In Service:					
18	Depreciation	2,274,836,782	1,705,515,338	447,029,979		122,291,465
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	190,221,535	34,493,762	732,117		154,995,656
22	TOTAL In Service (Total of lines 18 thru 21)	2,465,058,317	1,740,009,100	447,762,096		277,287,121
23	Leased to Others					
24	Depreciation					
25	Amortization and Depletion					
26	TOTAL Leased to Others (Total of lines 24 and 25)					
27	Held for Future Use					
28	Depreciation					

Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization and Depletion						
Line No.	Item (a)	Total Company For the Current Quarter/Year (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Common (f)
29	Amortization					
30	TOTAL Held for Future Use (Total of lines 28 and 29)					
31	Abandonment of Leases (Natural Gas)					
32	Amortization of Plant Acquisition Adjustment					
33	TOTAL Accum. Provisions (Should agree with line 14 above)(Total of lines 22, 26, 30, 31, and 32)	2,465,058,317	1,740,009,100	447,762,096		277,287,121

FOOTNOTE DATA

(a) Concept: UtilityPlantInServicePropertyUnderCapitalLeases

Total of $70,132,733 relates to ROU Assets booked due to ASC 842

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Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Gas Plant in Service (Accounts 101, 102, 103, and 106)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	INTANGIBLE PLANT						
2	301 Organization						
3	302 Franchise and Consents						
4	303 MiscellaneousIntangiblePlant	2,585,617	40,119			38,847	2,664,583
5	Total Intangible Plant (Total of lines 2 thru 4)	2,585,617	40,119			38,847	2,664,583
6	PRODUCTION PLANT						
7	Natural Gas Production and Gathering Plant						
8	325.1 Producing Lands						
9	325.2 Producing Leaseholds						
10	325.3 Gas Rights						
11	325.4 RIghts-of-Way						
12	325.5 Other Land and Land Rights						
13	326 Gas Well Structures						
14	327 Field Compressor Station Structures						
15	328 Field Measuring and Regulating Station Structures						
16	329 Other Structures						
17	330 Producing Gas Wells-Well Construction						
18	331 Producing Gas Wells-Well Equipment						
19	332 Field Lines						
20	333 Field Compressor Station Equipment						
21	334 Field Measuring and Regulating Station Equipment						
22	335 Drilling and Cleaning Equipment						
23	336 Purification Equipment						
24	337 Other Equipment						
25	338 Unsuccessful Exploration and Development Costs						
26	339 Asset Retirement Costs for Natural Gas Production and Gathering Plant						
27	Total Production and Gathering Plant (Total of lines 8 thru 26)						
28	PRODUCTS EXTRACTION PLANT						

Gas Plant in Service (Accounts 101, 102, 103, and 106)							
Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
29	340 Land and Land Rights						
30	341 Structures and Improvements						
31	342 Extraction and Refining Equipment						
32	343 Pipe Lines						
33	344 Extracted Products Storage Equipment						
34	345 Compressor Equipment						
35	346 Gas Measuring and Regulating Equipment						
36	347 Other equipment						
37	348 Asset Retirement Costs for Products Extraction Plant						
38	Total Products Extraction Plant (Total of lines 29 thru 37)						
39	Total Natural Gas Production Plant (Total of lines 27 and 38)						
40	Manufactured Gas Production Plant (Submit supplementary information in a footnote)	59,924					59,924
41	Total Production Plant (Total of lines 39 and 40)	59,924					59,924
42	NATURAL GAS STORAGE AND PROCESSING PLANT						
43	Underground storage plant						
44	350.1 Land	1,313,516					1,313,516
45	350.2 Rights-of-Way	66,742					66,742
46	351 Structures and Improvements	2,098,287	469,829				2,568,116
47	352 Wells	18,474,314	469,829			(21,412)	18,922,731
48	352.1 Storage Leaseholds and Rights						
49	352.2 Reservoirs	1,667,492					1,667,492
50	352.3 Non-recoverable Natural Gas	5,810,311					5,810,311
51	353 Lines	2,230,522				(988)	2,229,534
52	354 Compressor Station Equipment	17,716,256	469,830				18,186,086
53	355 Measuring and Regulating Equipment	1,240,824	469,831			(255)	1,710,400
54	356 Purification Equipment	560,248					560,248
55	357 Other Equipment	2,232,027	469,829				2,701,856
56	358 Asset Retirement Costs for Underground Storage Plant						
57	Total Underground Storage Plant (Total of lines 44 thru 56)	53,410,539	2,349,148			(22,655)	55,737,032
58	Other Storage Plant						

Gas Plant in Service (Accounts 101, 102, 103, and 106)							
Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
59	360 Land and Land Rights						
60	361 Structures and Improvements						
61	362 Gas Holders						
62	363 Purification Equipment						
63	363.1 Liquefaction Equipment						
64	363.2 Vaporizing Equipment						
65	363.3 Compressor Equipment						
66	363.4 Measuring and Regulating Equipment						
67	363.5 Other Equipment						
68	363.6 Asset Retirement Costs for Other Storage Plant						
69	Total Other Storage Plant (Total of lines 58 thru 68)						
70	Base Load Liquefied Natural Gas Terminaling and Processing Plant						
71	364.1 Land and Land Rights						
72	364.2 Structures and Improvements						
73	364.3 LNG Processing Terminal Equipment						
74	364.4 LNG Transportation Equipment						
75	364.5 Measuring and Regulating Equipment						
76	364.6 Compressor Station Equipment						
77	364.7 Communications Equipment						
78	364.8 Other Equipment						
79	364.9 Asset Retirement Costs for Base Load Liquefied Natural Gas						
80	Total Base Load Liquified Natural Gas , Terminating and Processing Plant (Total of lines 71 thru 79)						
81	Total Nat'l Gas Storage and Processing Plant (Total of lines 57, 69, and 80)	53,410,539	2,349,148			(22,655)	55,737,032
82	TRANSMISSION PLAN						
83	365.1 Land and Land Rights						
84	365.2 Rights-of-Way						
85	366 Structures and Improvements						
86	367 Mains						
87	368 Compressor Station Equipment						
88	369 Measuring and Regulating Station Equipment						

Gas Plant in Service (Accounts 101, 102, 103, and 106)							
Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
89	370 Communication Equipment						
90	371 Other Equipment						
91	372 Asset Retirement Costs for Transmission Plant						
92	Total Transmission Plant (Total of line 81 thru 91)						
93	DISTRIBUTION PLANT						
94	374 Land and Land Rights	1,532,328	51,934			1	1,584,263
95	375 Structures and Improvements	2,151,098	94,170	16,331		7,546	2,236,483
96	376 Mains	671,777,189	34,646,104	690,918		(42,905)	705,689,470
97	377 Compressor Station Equipment						
98	378 Measuring and Regulating Station Equipment-General	12,448,254	688,466	1,216		11,133	13,146,637
99	379 Measuring and Regulating Station Equipment-City Gate	9,365,034	418,760	52,467		122,076	9,853,403
100	380 Services	421,652,768	30,009,641	236,967		10,169	451,435,611
101	381 Meters	159,124,709	11,578,968	3,684,638		53,445	167,072,484
102	382 Meter Installations						
103	383 House Regulators						
104	384 House Regulator Installations						
105	385 Industrial Measuring and Regulating Station Equipment	6,391,429	99,585			20,400	6,511,414
106	386 Other Property on Customers' Premises						
107	387 Other Equipment	539				62	601
108	388 Asset Retirement Costs for Distribution Plant						
109	Total Distribution Plant (Total of lines 94 thru 108)	1,284,443,348	77,587,628	4,682,537		181,927	1,357,530,366
110	GENERAL PLANT						
111	389 Land and Land Rights	3,918,517				385	3,918,902
112	390 Structures and Improvements	29,898,498	46,640	579,176		89,016	29,454,978
113	391 Office Furniture and Equipment	464,773				9,732	474,505
114	392 Transportation Equipment	19,237,738	1,892,556	630,690		43,164	20,542,768
115	393 Stores Equipment	85,263	157,881				243,144
116	394 Tools, Shop, and Garage Equipment	9,292,808	834,644	91,741		1,554	10,037,265
117	395 Laboratory Equipment	396,983	54,653			640	452,276
118	396 Power Operated Equipment	4,367,784		94,759			4,273,025
119	397 Communication Equipment	2,611,409	(147)	697,951		4,590	1,917,901

Gas Plant in Service (Accounts 101, 102, 103, and 106)							
Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
120	398 Miscellaneous Equipment	2,367	6,725				9,092
121	Subtotal (Total of lines 111 thru 120)	70,276,140	2,992,952	2,094,317		149,081	71,323,856
122	399 Other Tangible Property						
123	399.1 Asset Retirement Costs for General Plant						
124	Total General Plant (Total of lines 121, 122, and 123)	70,276,140	2,992,952	2,094,317		149,081	71,323,856
125	Total (Accounts 101 and 106)	1,410,775,568	82,969,847	6,776,854		347,200	1,487,315,761
126	Gas Plant Purchased (See Instruction 8)						
127	(Less) Gas Plant Sold (See Instruction 8)						
128	Experimental gas plant unclassified						
129	Total Gas Plant In Service (Total of lines 125 thru 128)	1,410,775,568	82,969,847	6,776,854		347,200	1,487,315,761

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Gas Plant Held for Future Use (Account 105)

Line No.	Description and Location of Property (a)	Date Originally Included in this Account (b)	Date Expected to be Used in Utility Service (c)	Balance at End of Year (d)
1	Gas Distribution Mains and Services, Coeur d'Alene, Idaho	03/01/2007	12/31/2026	190,585
45	Total			190,585

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Construction Work in Progress-Gas (Account 107)

Line No.	Description of Project (a)	Construction work in progress - Gas (Account 107) (b)	Estimated Additional Cost of Project (c)
1	Gas Replace-St&Hwy	1,971,126	1,344,188
2	Gas Distribution Non-Revenue Blanket	1,153,499	2,872,098
3	Gas Airway Heights HP Reinforcement	1,131,338	8,500,000
4	Minor Projects under $1,000,000	2,633,516	5,492,303
45	TOTAL	6,889,479	18,208,589

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

General Description of Construction Overhead Procedure

Line No.	Title (a)	Amount (b)	Entity Name (c)	Capitalization Ration (percent) (d)	Cost Rate Percentage (e)	Rate Indicator (f)
1. Components of Formula (Derived from actual book balances and actual cost rates):						
	(1) Average Short-Term Debt	S 168,971,000				
	(2) Short-Term Interest				s 1.38%	
	(3) Long-Term Debt	D 1,973,500,000		46.99%	d 5.06%	
	(4) Preferred Stock	P		0%	p	
	(5) Common Equity	C 2,057,681,877		48.99%	c 9.4%	
	(6) Total Capitaization	4,200,152,877		96%		
	(7) Average Construction Work in Progress Balance	W 183,994,000				

2. Gross Rate for Borrowed Funds s(S/W) + d[(D/(D+P+C)) (1-(S/W))] -	1.47%
3. Rate for Other Funds [1-(S/W)] [p(P/(D+P+C)) + c(C/(D+P+C))] -	0.39%
4. Weighted Average Rate Actually Used for the Year:	
(a) Rate for Borrowed Funds -	
(b) Rate for Other Funds -	

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Accumulated Provision for Depreciation of Gas Utility Plant (Account 108)

Line No.	Item (a)	Total (c+d+e) (b)	Gas Plant in Service (c)	Gas Plant held for Future Use (d)	Gas Plant Leased to Others (e)
	Section A. BALANCES AND CHANGES DURING YEAR				
1	Balance Beginning of Year	421,097,745	421,097,745		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	40,926,795	40,926,795		
4	(403.1) Depreciation Expense for Asset Retirement Costs	0			
5	(413) Expense of Gas Plant Leased to Others				
6	Transportation Expenses - Clearing	1,339,464	1,339,464		
7	Other Clearing Accounts				
8	Other Clearing (Specify) (footnote details):				
9.1					
9.2					
9.3					
9.4					
9.5					
10	TOTAL Deprec. Prov. for Year (Total of lines 3 thru 8)	42,266,259	42,266,259	0	0
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(6,776,854)	(6,776,854)		
13	Cost of Removal	1,111,424	1,111,424		
14	Salvage (Credit)				
15	TOTAL Net Chrgs for Plant Ret. (Total of lines 12 thru 14)	(5,665,430)	(5,665,430)	0	0
16	Other Debit or Credit Items (Describe in footnote details)				
17.1		400,877	400,877		
17.2		2,338	2,338		
17.3		(237,283)	(237,283)		
17.4		(266,281)	(266,281)		
17.5		(3,126,675)	(3,126,675)		
17.6		(7,441,571)	(7,441,571)		
18	Book Cost of Asset Retirement Costs				
19	Balance End of Year (Total of lines 1,10,15,16 and 18)	447,029,979	447,029,979	0	0
	Section B. BALANCES AT END OF YEAR ACCORDING TO FUNCTIONAL CLASSIFICATIONS				

Accumulated Provision for Depreciation of Gas Utility Plant (Account 108)					
Line No.	Item (a)	Total (c+d+e) (b)	Gas Plant in Service (c)	Gas Plant held for Future Use (d)	Gas Plant Leased to Others (e)
21	Productions-Manufactured Gas				
22	Production and Gathering-Natural Gas				
23	Products Extraction-Natural Gas				
24	Underground Gas Storage	19,998,349	19,998,349		
25	Other Storage Plant				
26	Base Load LNG Terminaling and Processing Plant				
27	Transmission				
28	Distribution	401,782,110	401,782,110		
29	General	25,249,520	25,249,520		
30	TOTAL (Total of lines 21 thru 29)	447,029,979	447,029,979	0	0

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Gas Stored (Accounts 117.1, 117.2, 117.3, 117.4, 164.1, 164.2, and 164.3)

Line No.	Description (a)	(Account 117.1) (b)	(Account 117.2) (c)	Noncurrent (Account 117.3) (d)	(Account 117.4) (e)
1	Balance at Beginning of Year	6,992,076			
2	Gas Delivered to Storage				
3	Gas Withdrawn from Storage				
4	Other Debits and Credits				
5	Balance at End of Year	6,992,076	0	0	0
6	Dth	1,253,060			
7	Amount Per Dth	5.58			

Gas Stored (Accounts 117.1, 117.2, 117.3, 117.4, 164.1, 164.2, and 164.3)				
Line No.	Current (Account 164.1) (f)	LNG (Account 164.2) (g)	LNG (Account 164.3) (h)	Total (i)
1	9,535,324		0	16,527,400
2	26,476,514			26,476,514
3	18,407,842			18,407,842
4	0			0
5	[(a)]17,603,996	0	0	24,596,072
6	6,003,195			7,256,255
7	2.9324			3.3896

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: GasStoredCurrent

Fuel is accounted for within injections and withdrawal accounts.

All gas reported is current working gas. Avista uses the inventory method to report all working gas stored.

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Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Investments (Account 123, 124, and 136)

Line No.	Description of Investment (a)	* (b)	Date Acquired (c)	Date Matured (d)	Book Cost at Beginning of Year (If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference) (e)	Purchases or Additions During the Year (f)	Sales or Other Dispositions During Year (g)	Principal Amount (h)	No. of Shares at End of Year (i)	Book Cost at End of Year (If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference) (j)	Revenues for Year (k)	Gain or Loss from Investment Disposed of (l)
1	Investment in Avista Capital II (123010)	false	01/01/1997		11,547,000					11,547,000		
2	Total Investment in Associated Companies				11,547,000	0	0			11,547,000	0	0
1	Other Investment - WZN Loans Sandpoint (124350)				59,355					59,355		
2	Other Investment - Coli Cash Value (124600)				31,569,812		(3,055,492)			34,625,304		
3	Other Investment - Coli Borrowings (124610)				(31,569,812)		3,055,492			(34,625,304)		
4	Other Investment - WZN Loans Oregon (124680)				18,535					18,535		
5	Total Other Investments				77,890	0	0			77,890	0	0
1	Temp Cash Investments (136000)				152,774	467				153,241		
2	Total Temporary Cash Investments				152,774	467	0			153,241	0	0
4	Total Investments											

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Investments in Subsidiary Companies (Account 123.1)

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary earnings for 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		256,138,970			256,138,970	
2	Investment in AERC			89,816,380			89,816,380	
3	AERC - Equity in Earnings			16,790,283	6,909,964	5,000,000	18,700,247	
4	Avista Capital - Equity in Earnings			(155,335,303)	16,645,418		(138,689,885)	
40	TOTAL Cost of Account 123.1 $		Total	207,410,330	23,555,382	5,000,000	225,965,712	0

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Prepayments (Acct 165), Extraordinary Property Losses (Acct 182.1), Unrecovered Plant and Regulatory Study Costs (Acct 182.2)

Line No.	Nature of Payment (a)	Balance at End of Year (in dollars) (b)
	PREPAYMENTS (ACCOUNT 165)	
1	Prepaid Insurance	3,402,415
2	Prepaid Rents	206
3	Prepaid Taxes	4,273,517
4	Prepaid Interest	
5	Miscellaneous Prepayments	15,297,506
6	TOTAL	22,973,644

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Other Regulatory Assets (Account 182.3)

Line No.	Description and Purpose of Other Regulatory Assets (a)	Amortization Period (b)	Regulatory Citation (c)	Balance at Beginning Current Quarter/Year (d)	Debits (e)
1	[(a)](#) WA Excess Nat Gas Line Extension Allowance	3 years		8,597,671	0
2	[(b)](#) Reg Asset Post Ret Liabilility			202,321,377	6,863,397
3	[(c)](#) Regulatory Asset FAS 109 Utility Plant			93,708,282	1,785,604
4	Regulatory Asset FAS 109 DSIT Non Plant			2,344,905	2,594,946
5	Regulatory Asset Lake CDA Settlement-Varies	50 years	WA Docket UE-080416, ID Order AVU-E-08-01	40,042,767	0
6	[(d)](#) Reg Assets-Decoupling Surcharges - 2 years			10,093,117	16,072,572
7	Reg Asset - Colstrip	WA Electric - 33.75 years, ID Electric - 34.75 years	WA Dockets UE-190334, UG-190335, UE-190222 ID Order 34276, AVU-E-19-03	7,891,134	4,844,304
8	Regulatory Asset Commodity MTM ST & LT		WA Docket UE-002066, ID Order# 28648	7,794,852	40,479,053
9	[(e)](#) Regulatory Asset FAS 143 Asset Retirement Obligation			1,916,300	121,561
10	[(f)](#) Regulatory Asset Workers Comp			1,017,959	263,400
11	[(g)](#) Interest Rate Swap Asset			214,851,166	359,365,554
12	[(h)](#) DSM Asset			3,813,813	1,693,097
13	[(i)](#) Deferred ITC			3,910,987	0
14	Regulatory Asset MDM System		WA Dockets UE-180418, UG-180419	26,378,924	12,510,989
15	[(j)](#) Regulatory Asset BPA Residential Exchange			1,484,961	1,441,496
16	Regulatory Asset FISERV	3 years	Idaho Order# 33494, Dockets AVU-E-16-01, AVU-E-19-04	2,720,100	0
17	[(k)](#) Regulatory Asset AFUDC (PIS,WIP) & Equity DFIT			52,370,433	83,632,429
18	Regulatory Asset ID PCA Deferral			2,547,168	14,419,413
19	Existing Meters/ERTS Retirement Def		WA Docket UE-002066, ID Order# 28648	25,913,958	891,495
20	[(l)](#) Regulatory Asset Colstrip Community Fund		WA Order 09, Dockets UE-190334, UE-190222	1,500,000	0
21	Regulatory Asset COVID-19		WA Order# 01, Dockets UE-200407, UG-200408, Idaho Order# 34718, Oregon Order# 20-401, Docket UM 2069	2,859,947	7,132,376
22	Regulatory Asset Energy Imbalance Market		Idaho Order# 34606	194,925	574,493

Other Regulatory Assets (Account 182.3)					
Line No.	Description and Purpose of Other Regulatory Assets (a)	Amortization Period (b)	Regulatory Citation (c)	Balance at Beginning Current Quarter/Year (d)	Debits (e)
23	Regulatory Asset Oregon CAT Tax		Oregon Order# 20-398, Docket UM-2042	829,587	93,982
24	Regulatory Asset- Wildfire Resiliency		WA Dockets UE-200900, UG-200901, UE-200894, Idaho Order 34883	1,006,452	3,376,998
25	Deferral for CS2 & Colstrip (O&M, Excess Depr)		WA Order 09, Dockets UE-190334, UG-190335, UE-190222	1,108,935	4,711,925
26	(m) Regulatory Asset Tax Basis Flow through		WA Order01, Dockets UE-200895, UG-200896, Idaho Case#s AVU-E-20-12, AVU-G-20-07 Order# 34906, Oregon Docket# UM 2124 Order# 21-131	0	131,806,591
27	Tax Reform Deferral	1 year	Oregon Advice# 19-01-G	0	685,595
28	(n) Other Regulatory Assets			61,923	60,168
40	TOTAL			717,281,643	695,421,438

Other Regulatory Assets (Account 182.3)				
Line No.	Written off During Quarter/Year Account Charged (f)	Written off During Period Amount Recovered (g)	Written off During Period Amount Deemed Unrecoverable (h)	Balance at End of Current Quarter/Year (i)
1	407	2,134,643		6,463,028
2	228	37,813,141		171,371,633
3	283	1,588,902		93,904,984
4	283	2,592,721		2,347,130
5	407	1,116,805		38,925,962
6	456, 495	15,285,711		10,879,978
7	407	1,942,176		10,793,262
8	244, 175	32,888,608		15,385,297
9		0		2,037,861
10	242	394,351		887,008
11	Various	374,462,938		199,753,782
12	Various	1,532,733		3,974,177
13	283, 410	70,968		3,840,019
14	407, 419	2,882,249		36,007,664
15	407	1,786,380		1,140,077
16	407, 419	1,627,243		1,092,857
17	Various	80,968,179		55,034,683
18	557, 419	6,191,599		10,774,982
19	108, 407	5,389,928		21,415,525
20		0		1,500,000
21	186, 407	8,011,896		1,980,427
22	407	53,629		715,789
23	407, 419	24,949		898,620
24	407	0		4,383,450
25	407	710,974		5,109,886
26		0		131,806,591
27		0		685,595
28	407, 419	69,450		52,641
40		579,540,173	0	833,162,908

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. Amortization 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
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.
(e) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Regulatory 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.
(f) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Quarterly adjustments to workers comp reserve for current unpaid claims.
(g) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Settled swaps are amortized over the life of the associated debt.
(h) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Amortization period varies depending on timing of transactions.
(i) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Amortization period varies depending on underlying transactions.
(j) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Avista is a participant in the Residential Exchange Program with Bonneville Power Administration. Customers served under Schedules 1, 12, 22, 32, and 48 are given a rate adjustment based on Schedule 59 for Washington and Idaho. Amortization is based on customer usage.
(k) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Deferring the difference between FERC formula and State approved AFUDC rates from 2010 to present.
(l) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Deferral of customer portion for future rate recovery. The funds are set aside to help the Colstrip community transition away from economic activity related to coal-fired generation.
(m) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Accounting method change for federal income tax expense associated with Industry Director Directive No. 5 mixed service costs for meters.
(n) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Deferred Regulatory Fees of $26,308 refers to Oregon Docket# UG 415, Advice# 21-06-G. Amortization for 1 year.

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Miscellaneous Deferred Debits (Account 186)

Line No.	Description of Miscellaneous Deferred Debits (a)	Amortization Period (b)	Balance at Beginning of Year (c)	Debits (d)	Credits Account Charged (e)
1	Reg Asset - Battery Storage		0	3,848,745	
2	Colstrip Common Facility		3,466,641		
3	Plant Alloc of Clearing Journal		3,964,981	4,153,244	
4	Reg Asset - ERM		0	7,929,925	
5	Gas Supply Transactions		517,205	15,686	
6	WA REC Deferral		394,831		557
7	Reg Asset - Decoupling Deferred		15,376,953		VAR
8	Reg Asset - COVID 19 Deferral		5,305,694	6,304,500	
9	Nez Perce Settlement		119,125		VAR
10	(a) Timber Harvest		(226,818)		253
11	Union Contract Nego		11,703	110,016	
12	Misc. Deferred Debits <$100,000		896,248		VAR
13	ERM, DSM & BPA Tariff Riders Expense		0	181,230	
39	Miscellaneous Work in Progress				
40	TOTAL		29,826,563	22,543,346	

Miscellaneous Deferred Debits (Account 186)		
Line No.	Credits Amount (f)	Balance at End of Year (g)
1		3,848,745
2		3,466,641
3		8,118,225
4		7,929,925
5		532,891
6	394,831	0
7	1,201,997	14,174,956
8		11,610,194
9	5,188	113,937
10	(226,818)	0
11		121,719
12	231,787	664,461
13		181,230
39		
40	1,606,985	50,762,924

FOOTNOTE DATA

(a) Concept: DescriptionOfMiscellaneousDeferredDebits

At 12/31/2020, this credit was embedded in a suspense account with multiple other debit amounts which fully offset this credit balance. This credit amount has been embedded in the suspense account since 2015, the Company identified this amount during 2021 and reclassified it to account 253 as of 12/31/2021.

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Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Accumulated Deferred Income Taxes (Account 190)

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Changes During Year Amounts Debited to Account 410.1 (c)	Changes During Year, Amounts Credited to Account 411.1 (d)	Changes During Year Amounts Debited to Account 410.2 (e)	Changes During Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Account No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1	Account 190										
2	Electric	102,475,097	(15,481,995)	1,512,846	781,048	70,688	254	3,579,650			115,179,928
3	Gas	21,374,121	(11,601,746)	(77,389)	2,130	13,328	254	2,614,140			30,295,536
4	Other (Define)	92,879,318	1,246,322	5,342,581	2,106,334	2,859,126			254	13,158,741	[a]110,887,110
5	Total (Total of lines 2 thru 4)	216,728,536	(25,837,419)	6,778,038	2,889,512	2,943,142		6,193,790		13,158,741	256,362,574
6	Other (Specify)										
7	TOTAL Account 190 (Total of lines 5 thru 6)	216,728,536	(25,837,419)	6,778,038	2,889,512	2,943,142		6,193,790		13,158,741	256,362,574
8	Classification of TOTAL										
9	Federal Income Tax	216,728,536	(25,837,419)	6,778,038	2,889,512	2,943,142		6,193,790		13,158,741	256,362,574
10	State Income Tax										
11	Local Income Tax										

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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

	Beg Balance	End Balance
Pension, Medical, and SERP	33,779,058	49,617,069
Federal Income Tax Carryforwards	11,857,126	19,821,038
State Income Tax Carryforwards	18,682,559	18,379,565
Derivative Instruments	10,930,946	8,903,303
Compensation and Payroll	7,695,408	6,589,381
Plant Excess Deferred Gross Up	8,069,077	6,552,622
Other Common Deferred Tax Assets	1,865,144	1,024,132
Total	92,879,318	110,887,110

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Capital Stock (Accounts 201 and 204)

Line No.	Class and Series of Stock and Name of Stock Exchange (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 amt outstanding without reduction for amts held by respondent) Shares (e)	Outstanding per Bal. Sheet 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			71,497,523	1,341,011,707				
3	Restricted Shares								96,127	3,598,034
4										
5	Total	200,000,000			71,497,523	1,341,011,707				
6	Preferred Stock (Account 204)									
7	Cumulative	10,000,000								
8										
9										
10	Total	10,000,000			0	0				
Historical Data										
11	Common & Preferred Stock	210,000,000			71,497,523	1,341,011,707				
12	Total	210,000,000			71,497,523	1,341,011,707				

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Other Paid-In Capital (Accounts 208-211)

Line No.	Item (a)	Amount (b)
1	Donations Received from Stockholders (Account 208)	
2	Beginning Balance Amount	
3	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	
5	Reduction in Par or Stated Value of Capital Stock (Account 209)	
6	Beginning Balance Amount	
7	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)	
10	Beginning Balance Amount	
11	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	
13	Miscellaneous Paid-In Capital (Account 211)	
14	Beginning Balance Amount	(10,696,711)
15	Increases (Decreases) Due to Miscellaneous Paid-In Capital	
16	Ending Balance Amount	(10,696,711)
17	Other Paid in Capital	
18	Beginning Balance Amount	
19	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	(10,696,711)

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Securities Issued or Assumed and Securities Refunded or Retired During the Year

1. Furnish a supplemental statement briefly describing security financing and refinancing transactions during the year and the accounting for the securities, discounts, premiums, expenses, and related gains or losses. Identify as to Commission authorization numbers and dates.
2. Provide details showing the full accounting for the total principal amount, par value, or stated value of each class and series of security issued, assumed, retired, or refunded and the accounting for premiums, discounts, expenses, and gains or losses relating to the securities. Set forth the facts of the accounting clearly with regard to redemption premiums, unamortized discounts, expenses, and gain or losses relating to securities retired or refunded, including the accounting for such amounts carried in the respondent's accounts at the date of the refunding or refinancing transactions with respect to securities previously refunded or retired.
3. Include in the identification of each class and series of security, as appropriate, the interest or dividend rate, nominal date of issuance, maturity date, aggregate principal amount, par value or stated value, and number of shares. Give also the issuance of redemption price and name of the principal underwriting firm through which the security transactions were consummated.
4. Where the accounting for amounts relating to securities refunded or retired is other than that specified in General Instruction 17 of the Uniform System of Accounts, cite the Commission authorization for the different accounting and state the accounting method.
5. For securities assumed, give the name of the company for which the liability on the securities was assumed as well as details of the transactions whereby the respondent undertook to pay obligations of another company. If any unamortized discount, premiums, expenses, and gains or losses were taken over onto the respondent's books, furnish details of these amounts with amounts relating to refunded securities clearly earmarked.

In September 2021, the Company issued and sold $70.0 million of 2.90 percent first mortgage bonds due in 2051 pursuant to a bond purchase agreement with institutional investors in the private placement market. In December 2021, the Company issued and sold the remaining $70.0 million of bonds pursuant to the same agreement. The total net proceeds from the sale of the bonds were used to repay a portion of the outstanding balance under Avista Corp.'s $400.0 million committed line of credit. In connection with the pricing of the first mortgage bonds in September 2021, the Company cash settled four interest rate swap derivatives (notional aggregate amount of $45.0 million) and paid a net amount of $17.2 million. See Note 7 for a discussion of interest rate swap derivatives.

The new issuance is based on the following state commission orders:

1. Order of the Washington Utilities and Transportation Commission in Docket No. 190554 entered September 12, 2019.

1. Order of the Idaho Public Utilities Commission, Order No. 34386 entered July 31, 2019.

1. Order of the Public Utility Commission of Oregon, Order No. 19-249, entered July 30, 2019.

1. Order of the Public Service Commission of the State of Montana, Default Order No. 4535.

The Company issued common stock in 2021 for total net proceeds of $90.0 million. Most of these issuances came through the Company's sales agency agreements under which the sales agents may offer and sell new shares of common stock from time to time. The Company has board and regulatory authority to issue a maximum of 4.3 million shares under these agreements, of which 2.1 million remain unissued as of December 31, 2021. In 2021, 2.2 million shares were issued under these agreements resulting in total net proceeds of $88.5 million.

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Long-Term Debt (Accounts 221, 222, 223, and 224)

Line No.	Class and Series of Obligation and Name of Stock Exchange (a)	Nominal Date of Issue (b)	Date of Maturity (c)	Outstanding (Total amount outstanding without reduction for amts held by respondent) (d)	Interest for Year Rate (in %) (e)
1	Bonds (Account 221)				
2	FMBS - SERIES A - 7.53% DUE 05/05/2023	05/06/1993	05/05/2023	5,500,000	7.53%
3	FMBS - SERIES A - 7.54% DUE 5/05/2023	05/07/1993	05/05/2023	1,000,000	7.54%
4	FMBS - SERIES A - 7.18% DUE 8/11/2023	08/12/1993	08/11/2023	7,000,000	7.18%
5	FMBS - SERIES C - 6.37% DUE 06/18/2028	06/19/1998	06/19/2028	25,000,000	6.37%
6	FMBS - 6.25% DUE 12-01-35	11/17/2005	12/01/2035	150,000,000	6.25%
7	FMBS - 5.70% DUE 07-01-2037	12/15/2006	07/01/2037	150,000,000	5.7%
8	5.125% SERIES DUE 04-01-2022	09/22/2009	04/01/2022	250,000,000	5.125%
9	COLSTRIP 2010A PCRBs DUE 2032	12/15/2010	10/01/2032	66,700,000	0.128%
10	COLSTRIP 2010B PCRBs DUE 2034	12/15/2010	03/01/2034	17,000,000	0.128%
11	5.55% SERIES DUE 12-20-2040	12/20/2010	12/20/2040	35,000,000	5.55%
12	4.45% SERIES DUE 12-14-2041	12/14/2011	12/14/2041	85,000,000	4.45%
13	4.23% SERIES DUE 11-29-2047	11/30/2012	11/29/2047	80,000,000	4.23%
14	4.11% SERIES DUE 12-1-2044	12/18/2014	12/01/2044	60,000,000	4.11%
15	4.37% SERIES DUE 12-1-2045	12/16/2015	12/01/2045	100,000,000	4.37%
16	3.54% SERIES DUE 2051	12/15/2016	12/01/2051	175,000,000	3.54%
17	3.91% SERIES DUE 12-1-2047	12/14/2017	12/01/2047	90,000,000	3.91%
18	4.35% SERIES DUE 6-1-2048	05/22/2018	06/01/2048	375,000,000	4.35%
19	3.43% SERIES DUE 12-1-2049	11/26/2019	12/01/2049	180,000,000	3.43%
20	3.07% SERIES DUE 9-1-2050	09/30/2020	09/30/2050	165,000,000	3.07%
21	2.90% SERIES DUE 10/01/2051	09/28/2021	10/01/2051	140,000,000	2.9%
22	Subtotal			2,157,200,000	
23	Reacquired Bonds (Account 222)				
24	COLSTRIP 2010A PCRBs DUE 2032	12/15/2010	10/01/2032	66,700,000	0.128%
25	COLSTRIP 2010B PCRBs DUE 2034	12/15/2010	03/01/2034	17,000,000	0.128%
26	Subtotal			83,700,000	
27	Advances from Associated Companies (Account 223)				
28	ADVANCE ASSOCIATED-AVISTA CAPITAL II (ToPRS)	06/03/1997	06/01/2037	51,547,000	0.816%
29	Subtotal			51,547,000	
30	Other Long Term Debt (Account 224)				
31					
32					
33					

Long-Term Debt (Accounts 221, 222, 223, and 224)					
Line No.	Class and Series of Obligation and Name of Stock Exchange (a)	Nominal Date of Issue (b)	Date of Maturity (c)	Outstanding (Total amount outstanding without reduction for amts held by respondent) (d)	Interest for Year Rate (in %) (e)
34					
35					
36					
37					
38					
32	Subtotal			0	
40	TOTAL			2,292,447,000	

Long-Term Debt (Accounts 221, 222, 223, and 224)				
Line No.	Interest for Year Amount (f)	Held by Respondent Reacquired Bonds (Acct 222) (g)	Held by Respondent Sinking and Other Funds (h)	Redemption Price per $100 at End of Year (i)
1				
2	414,150			
3	75,400			
4	502,600			
5	1,592,500			
6	9,375,000			
7	8,550,000			
8	12,812,500			
9	85,106			
10	21,691			
11	1,942,500			
12	3,782,500			
13	3,384,000			
14	2,466,000			
15	4,370,000			
16	6,195,000			
17	3,519,000			
18	16,312,500			
19	6,174,000			
20	5,065,500			
21	693,583			
22	87,333,530		0	
23				
24	85,106	66,700,000		
25	21,691	17,000,000		
26	106,797	83,700,000	0	
27				
28	420,879			
29	420,879		0	
30				
31				
32				
33				
34				
35				
36				
37				

Long-Term Debt (Accounts 221, 222, 223, and 224)				
Line No.	Interest for Year Amount (f)	Held by Respondent Reacquired Bonds (Acct 222) (g)	Held by Respondent Sinking and Other Funds (h)	Redemption Price per $100 at End of Year (i)
38				
32				
40	87,861,206	83,700,000	0	

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Unamortized Debt Expense, Premium and Discount on Long-Term Debt (Accounts 181, 225, 226)

Line No.	Designation of Long-Term Debt (a)	Principal Amount of Debt Issued (b)	Total expense - Premium; Discount; or Debt Issuance Costs (c)	Amortization Period Date From (d)	Amortization Period Date To (e)
1	Unamortized Debt Expense (Account 181)				
2	FMBS - SERIES A - 7.53% DUE 05/05/2023	5,500,000	42,712	05/06/1993	05/05/2023
3	FMBS - SERIES A - 7.54% DUE 5/05/2023	1,000,000	7,766	05/07/1993	05/05/2023
4	FMBS - SERIES A - 7.18% DUE 8/11/2023	7,000,000	54,364	08/12/1993	08/11/2023
5	ADVANCE ASSOCIATED-AVISTA CAPITAL II (ToPRS)	51,547,000	1,296,086	06/03/1997	06/01/2037
6	FMBS - SERIES C - 6.37% DUE 06/18/2028	25,000,000	158,304	06/19/1998	06/19/2028
7	FMBS - 6.25% DUE 12-01-35	150,000,000	2,180,435	11/17/2005	12/01/2035
8	FMBS - 5.70% DUE 07-01-2037	150,000,000	4,924,304	12/15/2006	07/01/2037
9	5.125% SERIES DUE 04-01-2022	250,000,000	2,859,788	09/22/2009	04/01/2022
10	5.55% SERIES DUE 12-20-2040	35,000,000	258,834	12/20/2010	12/20/2040
11	4.45% SERIES DUE 12-14-2041	85,000,000	692,833	12/14/2011	12/14/2041
12	SHORT-TERM CREDIT FACILITY		9,677,662	12/14/2011	04/18/2022
13	4.23% SERIES DUE 11-29-2047	80,000,000	730,832	11/30/2012	11/29/2047
14	4.11% SERIES DUE 12-1-2044	60,000,000	428,205	12/18/2014	12/01/2044
15	4.37% SERIES DUE 12-1-2045	100,000,000	590,761	12/16/2015	12/01/2045
16	3.54% SERIES DUE 2051	175,000,000	1,042,569	12/15/2016	12/01/2051
17	3.91% SERIES DUE 12-1-2047	90,000,000	552,539	12/14/2017	12/01/2047
18	4.35% SERIES DUE 6-1-2048	375,000,000	4,625,198	06/01/2018	06/01/2048
19	3.43% SERIES DUE 12-1-2049	180,000,000	1,108,340	12/01/2019	12/01/2049
20	3.07% SERIES DUE 9-1-2050	165,000,000	1,071,782	09/30/2020	09/30/1950
21	2.90% SERIES DUE 10/01/2051	140,000,000	0	09/28/2021	10/01/2051
22	DEBT STRATEGIES	0	56,760	08/01/2005	08/01/2035
23	Rathrum 2005	0	71,647	09/30/2005	12/01/2035
24	Premium on Long-Term Debt (Account 225)				
25	FMBS - 6.25% DUE 12-01-35	150,000,000	2,180,435	11/17/2005	12/01/2035
26	Discount on Long-Term Debt (Account 226)				
27	FMBS - 6.25% DUE 12-01-35	150,000,000	2,180,435	11/17/2005	12/01/2035
28	FMBS - 5.70% DUE 07-01-2037	150,000,000	4,924,304	12/15/2006	07/01/2037
29	5.125% SERIES DUE 04-01-2022	250,000,000	2,859,788	09/22/2009	04/01/2022
30	4.35% SERIES DUE 6-1-2048	375,000,000	4,625,198	06/01/2018	06/01/2048

Unamortized Debt Expense, Premium and Discount on Long-Term Debt (Accounts 181, 225, 226)				
Line No.	Balance at Beginning of Year (f)	Debits During Year (g)	Credits During Year (h)	Balance at End of Year (i)
1				
2	3,441		1,424	2,017
3	626		259	367
4	4,832		1,812	3,020
5	231,245		14,015	217,230
6	39,576		5,277	34,299
7	905,662		60,378	845,284
8	2,550,065		153,773	2,396,292
9	242,487		181,865	60,622
10	172,561		8,628	163,933
11	485,183		23,104	462,079
12	1,834,574	348,956	(403,610)	2,587,140
13	562,184		20,886	541,298
14	342,772		14,282	328,490
15	492,538		19,702	472,836
16	923,609		29,794	893,815
17	497,408		18,423	478,985
18	3,882,267		141,174	3,741,093
19	1,068,434		36,843	1,031,591
20	1,065,928		(16,970)	1,082,898
21	0	1,068,315	24,270	1,044,045
22	419		29	390
23	35,527		2,368	33,159
24				
25	133,250	8,883		124,367
26				
27	316,122		21,075	295,047
28	120,376		7,259	113,117
29	60,927		45,695	15,232
30	346,226		12,590	333,636

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Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Unamortized Loss and Gain on Reacquired Debt (Accounts 189, 257)

Line No.	Designation of Long-Term Debt (a)	Date of Maturity (b)	Date Reacquired (c)	Principal of Debt Reacquired (d)	Net Gain or Loss (e)	Balance at Beginning of Year (f)	Balance at End of Year (g)
1	Unamortized Loss (Account 189)						
2	MISC DEBT REPURCHASES I		05/10/1993	0	4,695,395	138,869	94,633
3	ADVANCE ASSOCIATED-AVISTA CAPITAL II (ToPRS)	06/01/2037	12/18/2000	10,000,000	0	0	0
4	MISC 2002 REPURCHASE		12/31/2002	10,000,000	121,847	19,703	16,854
5	MISC 2003 REPURCHASE		12/31/2003	25,330,000	684,726	72,768	53,975
6	MISC 2005 REPURCHASE		12/31/2005	26,000,000	1,700,371	462,009	427,004
7	MISC 2008 REPURCHASE		12/31/2008	0	(43,132)	(8,226)	(5,530)
8	AVA CAPITAL TRUST III (2002)		04/01/2009	60,000,000	2,875,817	305,699	76,425
9	COLSTRIP 2010A PCRBs DUE 2032	03/01/2032	12/14/2010	66,700,000	3,709,174	1,842,069	1,686,401
10	COLSTRIP 2010B PCRBs DUE 2034	03/01/2034	12/14/2010	17,000,000	1,916,297	1,089,500	1,007,007
11	5.55% SERIES DUE 12-20-2040	12/20/2040	12/20/2010	30,000,000	5,263,822	3,509,214	3,333,754
12	4.23% SERIES DUE 11-29-2047	11/29/2047	06/28/2012	4,100,000	105,020	80,766	77,765
13	Unamortized Gain (Account 257)						
14	MISC DEBT REPURCHASES I		05/10/1993	0	0	0	0
15	ADVANCE ASSOCIATED-AVISTA CAPITAL II (ToPRS)	06/01/2037	12/18/2000	10,000,000	(1,769,125)	801,190	752,386
16	MISC 2002 REPURCHASE		12/31/2002	10,000,000	(2,350,000)	380,004	325,064
17	MISC 2003 REPURCHASE		12/31/2003	25,330,000	(1,000,000)	137,628	111,835
18	MISC 2005 REPURCHASE		12/31/2005	26,000,000	0	0	0
19	MISC 2008 REPURCHASE		12/31/2008	0	0	0	0
20	AVA CAPITAL TRUST III (2002)		04/01/2009	60,000,000	0	0	0
21	COLSTRIP 2010A PCRBs DUE 2032	03/01/2032	12/14/2010	66,700,000	0	0	0
22	COLSTRIP 2010B PCRBs DUE 2034	03/01/2034	12/14/2010	17,000,000	0	0	0
23	5.55% SERIES DUE 12-20-2040	12/20/2040	12/20/2010	30,000,000	0	0	0
24	4.23% SERIES DUE 11-29-2047	11/29/2047	06/28/2012	4,100,000	0	0	0

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes

Line No.	Details (a)	Amount (b)
1	Net Income for the Year (Page 114)	147,333,570
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Contributions in Aid of Construction	12,275,803
8	Total	12,275,803
9	Deductions Recorded on Books Not Deducted for Return	
10	Book Depreciation	246,404,844
11	Federal Income Tax Expense	4,716,706
12	State Income Tax Expense	291,365
13	Subsidiary Overheads	2,252,926
14	Other	65,355,817
13	Total	319,021,658
14	Income Recorded on Books Not Included in Return	
15	Subsidiary Earnings	23,555,382
16	Other	4,289,414
18	Total	27,844,796
19	Deductions on Return Not Charged Against Book Income	
20	Tax Depreciation	218,913,627
21	Plant Basis Adjustments	108,612,988
22	Other	123,939,170
26	Total	451,465,785
27	Federal Tax Net Income	(679,550)
28	Show Computation of Tax:	
29	Federal Tax at 21%	(142,706)
30	Prior Year True Ups	(157,137)
31	Customer refunds related to prior years at 35%	(481,833)
32	Total Federal Current Tax Expense	(781,676)

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Taxes Accrued, Prepaid and Charged During Year, Distribution of Taxes Charged (Show utility dept where applicable and acct charged)

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	Tax Jurisdiction (c)	Tax Year (d)	Balance at Beg. of Year Taxes Accrued (e)
1	Income Tax 2014	Federal Tax		2014	
2	Income Tax 2015	Federal Tax		2015	
3	Income Tax 2017	Federal Tax		2017	
4	Income Tax 2018	Federal Tax		2018	
5	Income Tax 2019	Federal Tax		2019	
6	Income Tax 2020	Federal Tax		2020	
7	Income Tax 2021	Federal Tax		2021	
8	**Subtotal Federal Tax**				0
9	Payroll Taxes 2020	Unemployment Tax	WA	2020	(235,053)
10	Payroll Taxes 2021	Unemployment Tax	WA	2021	
11	**Subtotal Unemployment Tax**				(235,053)
12	Property Tax 2020	Property Tax	WA	2020	18,089,813
13	Property Tax 2021	Property Tax	WA	2021	
14	Property Tax 2020	Property Tax	ID	2020	3,933,011
15	Property Tax 2021	Property Tax	ID	2021	
16	Property Tax 2018	Property Tax	MT	2018	
17	Property Tax 2020	Property Tax	MT	2020	5,898,062
18	Property Tax 2021	Property Tax	MT	2021	
19	Property Tax 2020	Property Tax	OR	2020	
20	Property Tax 2021	Property Tax	OR	2021	
21	**Subtotal Property Tax**				27,920,886
22	Excise Tax 2016	Excise Tax	WA	2016	892,951
23	Excise Tax 2020	Excise Tax	WA	2020	2,930,000
24	Excise Tax 2021	Excise Tax	WA	2021	
25	Corp Activities Tax-CAT 2020	Excise Tax	OR	2020	200,004
26	Corp Activities Tax-CAT 2021	Excise Tax	OR	2021	
27	Timber Excise Tax	Excise Tax	WA	2021	
28	Thermal Fuel Tax	Excise Tax	WA	2021	1,912
29	**Subtotal Excise Tax**				4,024,867
30	Natural Gas Use Tax	Sales And Use Tax	WA	2021	480
31	Sales And Use Tax 2019	Sales And Use Tax	WA	2019	(1)
32	Sales And Use Tax 2020	Sales And Use Tax	WA	2020	115,214
33	Sales And Use Tax 2021	Sales And Use Tax	WA	2021	
34	Sales And Use Tax 2020	Sales And Use Tax	ID	2020	27,502

Taxes Accrued, Prepaid and Charged During Year, Distribution of Taxes Charged (Show utility dept where applicable and acct charged)					
Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	Tax Jurisdiction (c)	Tax Year (d)	Balance at Beg. of Year Taxes Accrued (e)
35	Sales And Use Tax 2021	Sales And Use Tax	ID	2021	
36	**Subtotal Sales And Use Tax**				143,195
37	Municipal Occupation Tax	Local Tax	WA	2021	3,065,253
38	**Subtotal Local Tax**				3,065,253
39	Community Solar	Other Taxes	WA	2021	688
40	Hydro Relicensing	Other Taxes	ID	2021	
41	KWH Tax 2020	Other Taxes	ID	2020	28,115
42	KWH Tax 2021	Other Taxes	ID	2021	
43	Irrigation Credit 2020	Other Taxes	ID	2020	
44	Irrigation Credit 2021	Other Taxes	ID	2021	
45	Colstrip Generation Tax	Other Taxes	MT	2021	
46	KWH Tax 2020	Other Taxes	MT	2020	201,716
47	KWH Tax 2021	Other Taxes	MT	2021	
48	MISCELLANEOUS OTHER	Other Taxes			
49	WA Renewable Energy Credits	Other Taxes	WA	2021	
50	Misc Distribution	Other Taxes		2021	326
51	**Subtotal Other Taxes**				230,845
52	Income Tax 2019	State Tax	ID	2019	
53	Income Tax 2020	State Tax	ID	2020	
54	Income Tax 2021	State Tax	ID	2021	
55	Income Tax 2020	State Tax	MT	2020	
56	Income Tax 2021	State Tax	MT	2021	
57	Income Tax 2021	State Tax	OR	2021	
58	Income Tax 2021	State Tax	CA	2021	
59	**Subtotal State Tax**				0
60	Payroll Taxes 2020	Payroll Tax	ID	2020	(16,105)
61	Payroll Taxes 2021	Payroll Tax	ID	2021	
62	Payroll Taxes 2020	Payroll Tax	MT	2020	(4,910)
63	Payroll Taxes 2020	Payroll Tax	OR	2020	(9,574)
64	Payroll Taxes 2021	Payroll Tax	OR	2021	
65	Payroll Taxes 2020	Payroll Tax		2020	(402)
66	Payroll Taxes 2021	Payroll Tax		2021	
67	Payroll Taxes 2021	Payroll Tax		2021	8,019,298
68	**Subtotal Payroll Tax**				7,988,307
69	Franchise Tax 2019	Franchise Tax	ID	2019	14
70	Franchise Tax 2020	Franchise Tax	ID	2020	1,090,306

Taxes Accrued, Prepaid and Charged During Year, Distribution of Taxes Charged (Show utility dept where applicable and acct charged)					
Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	Tax Jurisdiction (c)	Tax Year (d)	Balance at Beg. of Year Taxes Accrued (e)
71	Franchise Tax 2021	Franchise Tax	ID	2021	
72	Franchise Tax 2020	Franchise Tax	OR	2020	1,038,154
73	Franchise Tax 2021	Franchise Tax	OR	2021	
74	**Subtotal Franchise Tax**				2,128,474
75	Consumer Council Fee	Other License And Fees Tax	MT	2021	58
76	Public Commission Fee	Other License And Fees Tax	MT	2021	42
77	**Subtotal Other License And Fees Tax**				100
78	Income Tax 2021	Income Tax		2021	
79	**Subtotal Income Tax**				0
40	Total				45,266,874

Taxes Accrued, Prepaid and Charged During Year, Distribution of Taxes Charged (Show utility dept where applicable and acct charged)					
Line No.	Balance at Beg. of Year Prepaid Taxes (f)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	Balance at End of Year Taxes Accrued (Account 236) (j)
1	0				0
2	0				0
3	0				0
4	0				0
5	0		(22,000,000)	(22,000,000)	0
6	0	(1,067,141)		1,067,141	0
7		33,162	545,000	511,838	0
8	0	(1,033,979)	(21,455,000)	(20,421,021)	0
9		0	62,298	0	(297,351)
10		877,216	583,051	1	294,166
11	0	877,216	645,349	1	(3,185)
12		(1)	8,794,393		9,295,419
13		18,194,877	8,800,184		9,394,693
14		(1,014)	3,932,039		(42)
15		7,788,449	3,905,993		3,882,456
16		240	240		0
17		10,258	5,908,319		1
18		9,550,410	4,794,326		4,756,084
19	(4,047,487)	4,072,730	25,246	(8,094,975)	0
20		4,273,508	8,547,022	1	0
21	(4,047,487)	43,889,457	44,707,762	(8,094,974)	27,328,611
22		(252,399)	640,552		0
23		10,827	2,922,485		18,342
24		28,713,253	25,720,692		2,992,561
25		(24,949)	300,000	124,945	0
26		800,000	750,000	(50,000)	0
27					0
28		87,594	81,329		8,177
29	0	29,334,326	30,415,058	74,945	3,019,080
30		4,881	4,382		979
31		(1)	(2)		0
32		69,975	184,299		890
33		1,369,417	1,232,495		136,922
34		(754)	26,781		(33)
35		144,335	137,350		6,985
36	0	1,587,853	1,585,305	0	145,743
37		25,138,504	25,102,476		3,101,281

Taxes Accrued, Prepaid and Charged During Year, Distribution of Taxes Charged (Show utility dept where applicable and acct charged)					
Line No.	Balance at Beg. of Year Prepaid Taxes (f)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	Balance at End of Year Taxes Accrued (Account 236) (j)
38	0	25,138,504	25,102,476	0	3,101,281
39			688		0
40		30,997	30,997		0
41		(545)	27,570		0
42		356,535	315,351		41,184
43		0	0		0
44		0	0		0
45					0
46		0	203,745		(2,029)
47		1,060,591	801,945		258,646
48					0
49		(754,446)	(752,135)		(2,311)
50		1,985			2,311
51	0	695,117	628,161	0	297,801
52			(329,840)	(329,840)	0
53		100	160	60	0
54		100	160	60	0
55		52	0	(52)	0
56		50	50		0
57		100,000	100,000		0
58		800	800		0
59	0	101,102	(228,670)	(329,772)	0
60		(1)	7,019		(23,125)
61		38,069	30,832		7,237
62		11,064	10,848		(4,694)
63		0	757		(10,331)
64		42,539	37,858		4,681
65			67		(469)
66			2,346		(2,346)
67		15,642,569	18,133,447		5,528,420
68	0	15,734,240	18,223,174	0	5,499,373
69					14
70		0	1,090,286		20
71		4,819,276	3,734,871		1,084,405
72		677	1,038,832		(1)
73		4,207,361	3,011,158		1,196,203
74	0	9,027,314	8,875,147	0	2,280,641

Taxes Accrued, Prepaid and Charged During Year, Distribution of Taxes Charged (Show utility dept where applicable and acct charged)					
Line No.	Balance at Beg. of Year Prepaid Taxes (f)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	Balance at End of Year Taxes Accrued (Account 236) (j)
75		(25)	25		8
76		164	181		25
77	0	139	206	0	33
78		950	850	(100)	0
79	0	950	850	(100)	0
40	(4,047,487)	125,352,239	108,499,818	(28,770,921)	41,669,378

Line No.	Balance at End of Year Prepaid Taxes (Included in Acct 165) (k)	Electric (Account 408.1, 409.1) (l)	Gas (Account 408.1, 409.1) (m)	Other Utility Dept. (Account 408.1, 409.1) (n)	Other Income and Deductions (Account 408.2, 409.2) (o)
Taxes Accrued, Prepaid and Charged During Year, Distribution of Taxes Charged (Show utility dept where applicable and acct charged)					
1					
2					
3					
4					
5					
6		(1,108,994)	1,956,185		(1,025,144)
7		(432)	(188)		(1,076,218)
8	0	(1,109,426)	1,955,997	0	(2,101,362)
9					
10		3,034,798	760,244	(2,919,714)	1,888
11	0	3,034,798	760,244	(2,919,714)	1,888
12					
13		14,462,413	3,600,388		132,076
14		(1,014)			
15		6,129,636	1,633,344		25,469
16		240			
17		10,258			
18		9,550,410			
19	4	1,765,170	2,307,560		
20	4,273,513	1,813,436	2,460,232		
21	4,273,517	33,730,549	10,001,524	0	157,545
22					
23		10,093	(7,589)		8,339
24		22,359,019	6,179,284		171,141
25					(24,949)
26					800,000
27					
28					
29	0	22,369,112	6,171,695	0	954,531
30		4,881			
31					
32					(880)
33					
34					
35					
36	0	4,881	0	0	(880)
37		19,544,378	5,612,963		

Taxes Accrued, Prepaid and Charged During Year, Distribution of Taxes Charged (Show utility dept where applicable and acct charged)					
Line No.	Balance at End of Year Prepaid Taxes (Included in Acct 165) (k)	Electric (Account 408.1, 409.1) (l)	Gas (Account 408.1, 409.1) (m)	Other Utility Dept. (Account 408.1, 409.1) (n)	Other Income and Deductions (Account 408.2, 409.2) (o)
38	0	19,544,378	5,612,963	0	0
39					
40		30,997			
41		(545)			
42		356,535			
43		(2,028)			
44		2,999			
45					
46					
47		1,060,591			
48					
49					
50		1,014			
51	0	1,449,563	0	0	0
52					
53		85	15		
54		85	15		
55		52			
56		50			
57		30,332	70,186		
58					800
59	0	30,604	70,216	0	800
60					
61		542,188	117,867	(624,538)	2,551
62		157,034		11,064	
63					
64		7,525	279,878	(247,761)	2,896
65					
66					
67				7,872,399	221,299
68	0	706,747	397,745	7,011,164	226,746
69					
70		(953)	(343)		
71		3,674,464	1,149,983		
72			(353)		
73			4,210,581		
74	0	3,673,511	5,359,868	0	0

Taxes Accrued, Prepaid and Charged During Year, Distribution of Taxes Charged (Show utility dept where applicable and acct charged)					
Line No.	Balance at End of Year Prepaid Taxes (Included in Acct 165) (k)	Electric (Account 408.1, 409.1) (l)	Gas (Account 408.1, 409.1) (m)	Other Utility Dept. (Account 408.1, 409.1) (n)	Other Income and Deductions (Account 408.2, 409.2) (o)
75		(25)			
76		164			
77	0	139	0	0	0
78		335	97		
79	0	335	97	0	0
40	4,273,517	83,435,191	30,330,349	4,091,450	(760,732)

Taxes Accrued, Prepaid and Charged During Year, Distribution of Taxes Charged (Show utility dept where applicable and acct charged)					
Line No.	Extraordinary Items (Account 409.3) (p)	Other Utility Opn. Income (Account 408.1, 409.1) (q)	Adjustment to Ret. Earnings (Account 439) (r)	Other (s)	State/Local Income Tax Rate (t)
1					
2					
3					
4					
5					
6				(889,188)	
7				1,110,000	
8	0	0	0	220,812	
9					
10					
11	0	0	0	0	
12					
13					
14					
15					
16					
17					
18					
19					
20				(160)	
21	0	0	0	(160)	
22				(252,399)	
23				(16)	
24				3,809	
25					
26					
27					
28				87,594	
29	0	0	0	(161,012)	
30					
31				(3)	
32				70,855	
33				1,369,417	
34				(754)	
35				144,335	
36	0	0	0	1,583,850	
37				(18,837)	

Line No.	Extraordinary Items (Account 409.3) (p)	Other Utility Opn. Income (Account 408.1, 409.1) (q)	Adjustment to Ret. Earnings (Account 439) (r)	Other (s)	State/Local Income Tax Rate (t)
38	0	0	0	(18,837)	
39					
40					
41					
42					
43				2,028	
44				(2,999)	
45					
46					
47					
48					
49				(754,446)	
50				971	
51	0	0	0	(754,446)	
52					
53					
54					
55					
56					
57				(518)	
58					
59	0	0	0	(518)	
60					
61					
62				(157,034)	
63					
64					
65					
66					
67				7,548,872	
68	0	0	0	7,391,838	
69					
70				1,296	
71				(5,171)	
72				1,030	
73				(3,220)	
74	0	0	0	(6,065)	

Taxes Accrued, Prepaid and Charged During Year, Distribution of Taxes Charged (Show utility dept where applicable and acct charged)					
Line No.	Extraordinary Items (Account 409.3) (p)	Other Utility Opn. Income (Account 408.1, 409.1) (q)	Adjustment to Ret. Earnings (Account 439) (r)	Other (s)	State/Local Income Tax Rate (t)
75					
76					
77	0	0	0	0	
78				518	
79	0	0	0	518	
40	0	0	0	8,255,980	

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Miscellaneous Current and Accrued Liabilities (Account 242)

Line No.	Item (a)	Balance at End of Year (b)
1	MISC LIAB-MARGIN CALL DEPOSIT	1,085,000
2	MISC LIAB-FOREST USE PERMITS	2,366,656
3	MISC LIAB - SUA JPMORGAN CHASE	1,151,810
4	ACCTS PAY - SOFTWARE LICENSES - ST	434,664
5	ST LEASE ACCRUAL	5,354
6	MISC LIAB-FERC ADMIN FEE ACC	625,000
7	MISC LIAB-FERC ELEC ADMIN CHG	120,153
8	MISC LIAB-MT LEASE PAYMENTS	5,169,000
9	MISC LIAB-MT INVASIVE SPECIES FEE	194,165
10	MISC LIAB-PAID TIME OFF	27,281,191
11	MIISC LIAB- OL DONATION POOL	21,143
12	EMPLOYEE RELIEF FUND	707
13	WORKERS COMP LIABILITY	887,008
14	ACCTS PAYABLE INVENTORY ACCRUALS-SC	267,174
15	ACCTS PAYABLE EXPENSE ACCRUAL-SC	4,846,020
16	CURRENT PORTION-BENEFIT LIAB	13,581,697
17	CLEARING ACCOUNTS	23,449
18	PREPAYMENTS	1,000,311
19	CUSTOMER ACCOUNTS	10,049,373
45	Total	69,109,875

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Other Deferred Credits (Account 253)

Line No.	Description of Other Deferred Credits (a)	Balance at Beginning of Year (b)	Debit Contra Account (c)	Debit Amount (d)	Credits (e)	Balance at End of Year (f)
1	[(a)] Deferred Gas Exchange	1,125,000	495	5,343,750	5,625,000	1,406,250
2	Bills Pole Rentals	646,335	172	1,118,568	804,432	332,199
3	Defer Comp Active Execs	9,173,880	128	962,528	1,301,966	9,513,318
4	Executive Incent Plan	140,000	214	140,000		
5	Unbilled Revenue	105,445	908	16,104,598	18,158,584	2,159,431
6	[(b)] WA Energy Recovery Mechanism	11,383,248	186	11,383,248		
7	[(c)] Decoupling Deferred Credits	1,855,168	182, 456, 495	1,131,297	6,189,577	6,913,448
8	[(d)] Reg Liability-COVID-19 Deferral	6,660,724			1,088,376	7,749,100
9	[(e)] WA REC Deferrals		186, 431	51,900	1,440,095	1,388,195
10	[(f)] Misc Deferred Credits	360,229	186, 550, 514, 545	579,095	713,759	494,893
11	[(g)] Timber Harvest		186		226,818	226,818
45	TOTAL	31,450,029		36,814,984	35,548,607	30,183,652

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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 15, 2025.

(b) Concept: DescriptionOfOtherDeferredCredits

The Washington Energy Recovery Mechanism (ERM) allows Avista to periodically increase or decrease electric rates. This accounting method tracks differences between actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base rates.

(c) Concept: DescriptionOfOtherDeferredCredits

Washington and Idaho Decoupling mechanisms for electric and natural gas were extended through March 31, 2025. Oregon's decoupling mechanism for natural gas was approved beginning March 1, 2016.

Decoupling revenue deferrals are recognized during the period they occur, subject to certain limitations. Revenue is expected to be collected within 24 months of the deferral.

(d) Concept: DescriptionOfOtherDeferredCredits

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

(e) Concept: DescriptionOfOtherDeferredCredits

Washington Docket UE-200505 Order 01. Rebate to Washington retail customers under Schedule 98 based on the projected net REC revenues.

(f) Concept: DescriptionOfOtherDeferredCredits

Kettle Falls Generation Station underground fuel leak of $64,140 - Continuing remediation liability is recorded.

(g) Concept: DescriptionOfOtherDeferredCredits

At 12/31/2020, this credit was embedded in a suspense account with multiple other debit amounts which fully offset this credit balance. This credit amount has been embedded in the suspense account since 2015, the Company identified this amount during 2021 and reclassified it to account 253 as of 12/31/2021.

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Accumulated Deferred Income Taxes-Other Property (Account 282)

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Changes During Year Amounts Debited to Account 410.1 (c)	Changes During Year Amounts Credited to Account 411.1 (d)	Changes During Year Amounts Debited to Account 410.2 (e)	Changes During Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Account No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1	Account 282										
2	Electric	398,244,120	9,376,181	70,652,238			182 / 254	71,392,284			408,360,347
3	Gas	143,910,347	4,199,524	49,365,500			182 / 254	50,206,033			148,950,404
4	Other (Define)	61,260,966	(740,059)				182 / 254	1,069,275			61,590,182
5	Total (Total of lines 2 thru 4)	603,415,433	12,835,646	120,017,738				122,667,592		0	618,900,933
6	Other (Specify)										0
7	TOTAL Account 282 (Total of lines 5 thru 6)	603,415,433	12,835,646	120,017,738				122,667,592		0	618,900,933
8	Classification of TOTAL										
9	Federal Income Tax	603,415,433	12,835,646	120,017,738				122,667,592			618,900,933
10	State Income Tax										0
11	Local Income Tax										0

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Accumulated Deferred Income Taxes-Other (Account 283)

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Changes During Year Amounts Debited to Account 410.1 (c)	Changes During Year Amounts Credited to Account 411.1 (d)	Changes During Year Amounts Debited to Account 410.2 (e)	Changes During Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Account No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1	Account 283										
2	Electric	12,928,052	7,073,200	263,167	19,136	1,179	182 / 254	17,909,782			37,665,824
3	Gas	3,042,547	7,431,692	611,207	113,646		182	12,426,198			22,402,876
4	Other (Define)	184,147,569	5,647,754	176,665	20,483		182 / 254	17,074,283			206,713,424
5	Total (Total of lines 2 thru 4)	200,118,168	20,152,646	1,051,039	153,265	1,179		47,410,263			266,782,124
6	Other (Specify)										
7	TOTAL Account 283 (Total of lines 5 thru 6)	200,118,168	20,152,646	1,051,039	153,265	1,179		47,410,263			266,782,124
8	Classification of TOTAL										
9	Federal Income Tax	200,118,168	20,152,646	1,051,039	153,265	1,179		47,410,263			266,782,124
10	State Income Tax										
11	Local Income Tax										

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Other Regulatory Liabilities (Account 254)

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	Written off during Quarter/Period Account Credited (c)	Written off During Period Amount Refunded (d)	Written off During Period Amount Deemed Non-Refundable (e)	Credits (f)	Balance at End of Current Quarter/Year (g)
1	(a) Idaho Investment Tax Credit	8,874,779	190	1,108,577		0	7,766,202
2	(b) Interest Rate Swaps	15,045,752	427, 175	17,886,002		17,902,790	15,062,540
3	Nez Perce	506,300	557	22,008		0	484,292
4	Idaho Earnings Test	686,970		0		0	686,970
5	(c) Decoupling Rebate	2,335,746	495, 182	3,571,861		4,154,224	2,918,109
6	(d) WA ERM	26,486,130	186, 557	19,067,343		12,401,822	19,820,609
7	(e) Deferred Federal ITC - Varies	7,821,976	190	141,936		0	7,680,040
8	(f) Plant Excess Deferred	382,938,797	190, 282	47,165,951		4,146,763	339,919,609
9	Reg Liability MDM System	897,416	431	11,291		78,050	964,175
10	(g) AFUDC Equity Tax Deferral	2,606,448	407	666,038		70,577	2,010,987
11	(h) Exist Meters/ERTS Excess Depr Deferred	1,879,242	182	2,571,853		692,611	0
12	(i) DSM Tariff Rider	540,275		0		5,827,354	6,367,629
13	(j) Low Income Energy Assistance	3,783,957	242, 908	160,974		3,120,839	6,743,822
14	(k) Reg Liability - OR Tax Strategy Deferral	0		0		1,322,007	1,322,007
15	(l) Reg Liability - Tax Reform Amortization - 1 year	994,068	407, 431	2,319,765		1,506,823	181,126
16	(m) Reg Liability - Energy Efficiency Assistance	1,532,183	242, 908	103,349		0	1,428,834
17	(n) Reg Liability - Colstrip Community Fund	3,357,111	232, 407	3,357,111		0	0
18	(o) Reg Liability - COVID-19 Deferral	4,288,655	407	187,911		650,402	4,751,146
19	(p) Reg Liability - Tax Customer Credit	0	190, 410	11,449,638		155,311,627	143,861,989
20	(q) Other Regulatory Liabilities - Varies	8,545,572	143, 190, 407	376,835		1,523,402	9,692,139
45	Total	473,121,377		110,168,443	0	208,709,291	571,662,225

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FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Not amortized.

(b) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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

(c) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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

(d) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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

(e) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Noxon ITC - 65 year amortization, ends 2077

Community Solar ITC - 20 year amortization, ends 2035

Nine Mile ITC - 65 year amortization, ends 2080

(f) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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

(g) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Washington Dockets UE-200900, UG-200901, UE-200894 effective 10/01/2021, amortization over one year.

Idaho Electric Settlement AVU-E-19-04 ordered a transfer to account 254320 for Idaho portion.

(h) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Washington Dockets UE-180418 and UG-180419

(i) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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

(j) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Washington Docket# UE-190912, UG-190920

Idaho Docket# AVU-E-18-12, AVU-G-18-08

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

(k) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Oregon Docket No. UM 2124 - Deferral of associated state tax savings of approximately $1.3M thru 12/31/2022.

(l) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Washington Dockets UE-170485, UG-170486 (Schedule 174, amortization ended 5/31/2019)

Oregon Advice# ADV 923/19-01-G (Schedule 474, amortization ended 2/28/2021)

Idaho Case# GNR-U-18-01 (Schedule 74, amortization ended 3/31/2020)

(m) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Avista's contribution in the Energy Assistance Fund as per Idaho Settlement Stipulation Case# AVU-E-19-04 (Page 10, #16 a.ii).

(n) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Washington Order 09 in Dockets UE-190334, UE-190222. Deferred funds from shareholders and customers to help the Colstrip community transition away from economic activity related to coal-fired generation.

(o) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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

(p) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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# UM 2124 Order# 21-131

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

(q) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Oregon BETC credit of $11,558 is not amortized.

Non Plant Excess Deferred balance of $74,329 amortized over 1 year.

Deferral of depreciation expense of $0.6M per Idaho Order No. 34276, Case Nos. AVU-E-18-03 and AVU-G-18-02.

State income tax net operating loss carryforward of $7.5M will reverse over the period in which we are able to utilize the loss to offset taxable income on the Idaho, Montana, and Oregon tax returns.

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Gas Operating Revenues

Line No.	Title of Account (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transaction Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Previous Year (e)
1	(480) Residential Sales				
2	(481) Commercial and Industrial Sales				
3	(482) Other Sales to Public Authorities				
4	(483) Sales for Resale				
5	(484) Interdepartmental Sales				
6	(485) Intracompany Transfers				
7	(487) Forfeited Discounts				
8	(488) Miscellaneous Service Revenues				
9	(489.1) Revenues from Transportation of Gas of Others Through Gathering Facilities				
10	(489.2) Revenues from Transportation of Gas of Others Through Transmission Facilities				
11	(489.3) Revenues from Transportation of Gas of Others Through Distribution Facilities				
12	(489.4) Revenues from Storing Gas of Others				
13	(490) Sales of Prod. Ext. from Natural Gas				
14	(491) Revenues from Natural Gas Proc. by Others				
15	(492) Incidental Gasoline and Oil Sales				
16	(493) Rent from Gas Property				
17	(494) Interdepartmental Rents				
18	(495) Other Gas Revenues				
19	Subtotal:	0	0	0	0
20	(496) (Less) Provision for Rate Refunds				
21	TOTAL	0	0	0	0

Gas Operating Revenues					
Line No.	**Other Revenues Amount for Current Year (f)**	**Other Revenues Amount for Previous Year (g)**	**Total Operating Revenues Amount for Current Year (h)**	**Total Operating Revenues Amount for Previous Year (i)**	**Dekatherm of Natural Gas Amount for Current Year (j)**
1	221,404,777	213,611,519	221,404,777	213,611,519	21,983,489
2	108,615,420	102,065,963	108,615,420	102,065,963	15,181,386
3	0	0	0	0	0
4	114,711,489	105,073,763	114,711,489	105,073,763	36,282,192
5	328,145	252,564	328,145	252,564	47,887
6	0	0	0	0	
7	0	0	0	0	
8	27,568	43,452	27,568	43,452	
9	0	0	0	0	0
10	0	0	0	0	0
11	8,547,319	7,916,862	8,547,319	7,916,862	17,901,306
12	0	0	0	0	0
13	0	0	0	0	
14	0	0	0	0	
15	0	0	0	0	
16	14,000	465	14,000	465	
17	0	0	0	0	
18	18,827,764	4,986,835	18,827,764	4,986,835	
19	472,476,482	433,951,423	472,476,482	433,951,423	
20	(1,093,458)	(3,192,858)	(1,093,458)	(3,192,858)	
21	473,569,940	437,144,281	473,569,940	437,144,281	

Gas Operating Revenues	
Line No.	Dekatherm of Natural Gas Amount for Previous Year (k)
1	21,998,766
2	14,793,672
3	0
4	54,966,875
5	36,886
6	
7	
8	
9	
10	0
11	18,573,063
12	0
13	
14	
15	
16	
17	
18	
19	
20	
21	

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Other Gas Revenues (Account 495)

Line No.	Description of Transaction (a)	Amount (in dollars) (b)
1	Commissions on Sale or Distribution of Gas of Others	
2	Compensation for Minor or Incidental Services Provided for Others	
3	Profit or Loss on Sale of Material and Supplies not Ordinarily Purchased for Resale	
4	Sales of Stream, Water, or Electricity, including Sales or Transfers to Other Departments	
5	Miscellaneous Royalties	
6	Revenues from Dehydration and Other Processing of Gas of Others except as provided for in the Instructions to Account 495	
7	Revenues for Right and/or Benefits Received from Others which are Realized Through Research, Development, and Demonstration Ventures	
8	Gains on Settlements of Imbalance Receivables and Payables	
9	Revenues from Penalties earned Pursuant to Tariff Provisions, including Penalties Associated with Cash-out Settlements	
10	Revenues from Shipper Supplied Gas	
11	Other revenues (Specify):	
12	Misc Bills	594,299
13	Deferred Exchange Revenue	5,343,750
14	Decoupling Deferred Revenue	12,889,716
40	TOTAL	18,827,765

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Gas Operation and Maintenance Expenses

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. PRODUCTION EXPENSES		
2	A. Manufactured Gas Production		
3	Manufactured Gas Production (Submit Supplemental Statement)		
4	B. Natural Gas Production		
5	B1. Natural Gas Production and Gathering		
6	Operation		
7	750 Operation Supervision and Engineering	0	
8	751 Production Maps and Records	0	
9	752 Gas Well Expenses	0	
10	753 Field Lines Expenses	0	
11	754 Field Compressor Station Expenses	0	
12	755 Field Compressor Station Fuel and Power	0	
13	756 Field Measuring and Regulating Station Expenses	0	
14	757 Purification Expenses	0	
15	758 Gas Well Royalties	0	
16	759 Other Expenses	0	
17	760 Rents	0	
18	TOTAL Operation (Total of lines 7 thru 17)	0	
19	Maintenance		
20	761 Maintenance Supervision and Engineering	0	
21	762 Maintenance of Structures and Improvements	0	
22	763 Maintenance of Producing Gas Wells	0	
23	764 Maintenance of Field Lines	0	
24	765 Maintenance of Field Compressor Station Equipment	0	
25	766 Maintenance of Field Measuring and Regulating Station Equipment	0	
26	767 Maintenance of Purification Equipment	0	
27	768 Maintenance of Drilling and Cleaning Equipment	0	
28	769 Maintenance of Other Equipment	0	
29	TOTAL Maintenance (Total of lines 20 thru 28)	0	
30	TOTAL Natural Gas Production and Gathering (Total of lines 18 and 29)	0	
31	B2. Products Extraction		
32	Operation		
33	770 Operation Supervision and Engineering	0	
34	771 Operation Labor	0	

Gas Operation and Maintenance Expenses			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
35	772 Gas Shrinkage	0	
36	773 Fuel	0	
37	774 Power	0	
38	775 Materials	0	
39	776 Operation Supplies and Expenses	0	
40	777 Gas Processed by Others	0	
41	778 Royalties on Products Extracted	0	
42	779 Marketing Expenses	0	
43	780 Products Purchased for Resale	0	
44	781 Variation in Products Inventory	0	
45	(Less) 782 Extracted Products Used by the Utility-Credit	0	
46	783 Rents	0	
47	TOTAL Operation (Total of lines 33 thru 46)	0	
48	Maintenance		
49	784 Maintenance Supervision and Engineering	0	
50	785 Maintenance of Structures and Improvements	0	
51	786 Maintenance of Extraction and Refining Equipment	0	
52	787 Maintenance of Pipe Lines	0	
53	788 Maintenance of Extracted Products Storage Equipment	0	
54	789 Maintenance of Compressor Equipment	0	
55	790 Maintenance of Gas Measuring and Regulating Equipment	0	
56	791 Maintenance of Other Equipment	0	
57	TOTAL Maintenance (Total of lines 49 thru 56)	0	
58	TOTAL Products Extraction (Total of lines 47 and 57)	0	
59	C. Exploration and Development		
60	Operation		
61	795 Delay Rentals	0	
62	796 Nonproductive Well Drilling	0	
63	797 Abandoned Leases	0	
64	798 Other Exploration	0	
65	TOTAL Exploration and Development (Total of lines 61 thru 64)	0	
66	D. Other Gas Supply Expenses		
67	Operation		
68	800 Natural Gas Well Head Purchases	0	
69	800.1 Natural Gas Well Head Purchases, Intracompany Transfers	0	
70	801 Natural Gas Field Line Purchases	0	
71	802 Natural Gas Gasoline Plant Outlet Purchases	0	
72	803 Natural Gas Transmission Line Purchases	0	

Gas Operation and Maintenance Expenses			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
73	804 Natural Gas City Gate Purchases	255,180,181	202,359,237
74	804.1 Liquefied Natural Gas Purchases	0	
75	805 Other Gas Purchases	0	
76	(Less) 805.1 Purchases Gas Cost Adjustments	19,288,831	4,674,021
77	TOTAL Purchased Gas (Total of lines 68 thru 76)	235,891,350	197,685,216
78	806 Exchange Gas	0	
79	Purchased Gas Expenses		
80	807.1 Well Expense-Purchased Gas	0	
81	807.2 Operation of Purchased Gas Measuring Stations	0	
82	807.3 Maintenance of Purchased Gas Measuring Stations	0	
83	807.4 Purchased Gas Calculations Expenses	0	
84	807.5 Other Purchased Gas Expenses	0	
85	TOTAL Purchased Gas Expenses (Total of lines 80 thru 84)	0	
86	808.1 Gas Withdrawn from Storage-Debit	18,407,841	17,913,784
87	(Less) 808.2 Gas Delivered to Storage-Credit	26,476,514	13,143,711
88	809.1 Withdrawals of Liquefied Natural Gas for Processing-Debit	0	
89	(Less) 809.2 Deliveries of Natural Gas for Processing-Credit	0	
90	Gas used in Utility Operation-Credit		
91	810 Gas Used for Compressor Station Fuel-Credit	0	
92	811 Gas Used for Products Extraction-Credit	1,018,164	297,348
93	812 Gas Used for Other Utility Operations-Credit	0	
94	TOTAL Gas Used in Utility Operations-Credit (Total of lines 91 thru 93)	1,018,164	297,348
95	813 Other Gas Supply Expenses	1,764,142	1,604,679
96	TOTAL Other Gas Supply Exp. (Total of lines 77,78,85,86 thru 89,94,95)	228,568,655	203,762,620
97	TOTAL Production Expenses (Total of lines 3, 30, 58, 65, and 96)	228,568,655	203,762,620
98	2. NATURAL GAS STORAGE, TERMINALING AND PROCESSING EXPENSES		
99	A. Underground Storage Expenses		
100	Operation		
101	814 Operation Supervision and Engineering	4,207	7,196
102	815 Maps and Records	0	
103	816 Wells Expenses	0	
104	817 Lines Expense	0	
105	818 Compressor Station Expenses	0	
106	819 Compressor Station Fuel and Power	0	
107	820 Measuring and Regulating Station Expenses	0	
108	821 Purification Expenses	0	

Gas Operation and Maintenance Expenses			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
109	822 Exploration and Development	0	
110	823 Gas Losses	0	
111	824 Other Expenses	889,434	805,804
112	825 Storage Well Royalties	0	
113	826 Rents	0	
114	TOTAL Operation (Total of lines of 101 thru 113)	893,641	813,000
115	Maintenance		
116	830 Maintenance Supervision and Engineering	0	
117	831 Maintenance of Structures and Improvements	0	
118	832 Maintenance of Reservoirs and Wells	0	
119	833 Maintenance of Lines	0	
120	834 Maintenance of Compressor Station Equipment	0	
121	835 Maintenance of Measuring and Regulating Station Equipment	0	
122	836 Maintenance of Purification Equipment	0	
123	837 Maintenance of Other Equipment	2,099,183	2,186,040
124	TOTAL Maintenance (Total of lines 116 thru 123)	2,099,183	2,186,040
125	TOTAL Underground Storage Expenses (Total of lines 114 and 124)	2,992,824	2,999,040
126	B. Other Storage Expenses		
127	Operation		
128	840 Operation Supervision and Engineering	0	
129	841 Operation Labor and Expenses	0	
130	842 Rents	0	
131	842.1 Fuel	0	
132	842.2 Power	0	
133	842.3 Gas Losses	0	
134	TOTAL Operation (Total of lines 128 thru 133)	0	
135	Maintenance		
136	843.1 Maintenance Supervision and Engineering	0	
137	843.2 Maintenance of Structures	0	
138	843.3 Maintenance of Gas Holders	0	
139	843.4 Maintenance of Purification Equipment	0	
140	843.5 Maintenance of Liquefaction Equipment	0	
141	843.6 Maintenance of Vaporizing Equipment	0	
142	843.7 Maintenance of Compressor Equipment	0	
143	843.8 Maintenance of Measuring and Regulating Equipment	0	
144	843.9 Maintenance of Other Equipment	0	
145	TOTAL Maintenance (Total of lines 136 thru 144)	0	
146	TOTAL Other Storage Expenses (Total of lines 134 and 145)	0	

Gas Operation and Maintenance Expenses			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
147	C. Liquefied Natural Gas Terminaling and Processing Expenses		
148	Operation		
149	844.1 Operation Supervision and Engineering	0	
150	844.2 LNG Processing Terminal Labor and Expenses	0	
151	844.3 Liquefaction Processing Labor and Expenses	0	
152	844.4 Liquefaction Transportation Labor and Expenses	0	
153	844.5 Measuring and Regulating Labor and Expenses	0	
154	844.6 Compressor Station Labor and Expenses	0	
155	844.7 Communication System Expenses	0	
156	844.8 System Control and Load Dispatching	0	
157	845.1 Fuel	0	
158	845.2 Power	0	
159	845.3 Rents	0	
160	845.4 Demurrage Charges	0	
161	(less) 845.5 Wharfage Receipts-Credit	0	
162	845.6 Processing Liquefied or Vaporized Gas by Others	0	
163	846.1 Gas Losses	0	
164	846.2 Other Expenses	0	
165	TOTAL Operation (Total of lines 149 thru 164)	0	
166	Maintenance		
167	847.1 Maintenance Supervision and Engineering	0	
168	847.2 Maintenance of Structures and Improvements	0	
169	847.3 Maintenance of LNG Processing Terminal Equipment	0	
170	847.4 Maintenance of LNG Transportation Equipment	0	
171	847.5 Maintenance of Measuring and Regulating Equipment	0	
172	847.6 Maintenance of Compressor Station Equipment	0	
173	847.7 Maintenance of Communication Equipment	0	
174	847.8 Maintenance of Other Equipment	0	
175	TOTAL Maintenance (Total of lines 167 thru 174)	0	
176	TOTAL Liquefied Nat Gas Terminaling and Proc Exp (Total of lines 165 and 175)	0	
177	TOTAL Natural Gas Storage (Total of lines 125, 146, and 176)	2,992,824	2,999,040
178	3. TRANSMISSION EXPENSES		
179	Operation		
180	850 Operation Supervision and Engineering	0	
181	851 System Control and Load Dispatching	0	
182	852 Communication System Expenses	0	
183	853 Compressor Station Labor and Expenses	0	

Gas Operation and Maintenance Expenses			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
184	854 Gas for Compressor Station Fuel	0	
185	855 Other Fuel and Power for Compressor Stations	0	
186	856 Mains Expenses	0	
187	857 Measuring and Regulating Station Expenses	0	
188	858 Transmission and Compression of Gas by Others	0	
189	859 Other Expenses	0	
190	860 Rents	0	
191	TOTAL Operation (Total of lines 180 thru 190)	0	
192	Maintenance		
193	861 Maintenance Supervision and Engineering	0	
194	862 Maintenance of Structures and Improvements	0	
195	863 Maintenance of Mains	0	
196	864 Maintenance of Compressor Station Equipment	0	
197	865 Maintenance of Measuring and Regulating Station Equipment	0	
198	866 Maintenance of Communication Equipment	0	
199	867 Maintenance of Other Equipment	0	
200	TOTAL Maintenance (Total of lines 193 thru 199)	0	
201	TOTAL Transmission Expenses (Total of lines 191 and 200)	0	
202	4. DISTRIBUTION EXPENSES		
203	Operation		
204	870 Operation Supervision and Engineering	2,415,891	2,566,384
205	871 Distribution Load Dispatching	0	
206	872 Compressor Station Labor and Expenses	0	
207	873 Compressor Station Fuel and Power	0	
208	874 Mains and Services Expenses	6,634,792	6,767,956
209	875 Measuring and Regulating Station Expenses-General	194,891	213,070
210	876 Measuring and Regulating Station Expenses-Industrial	3,534	6,318
211	877 Measuring and Regulating Station Expenses-City Gas Check Station	101,935	69,259
212	878 Meter and House Regulator Expenses	950,976	905,675
213	879 Customer Installations Expenses	2,537,313	2,471,877
214	880 Other Expenses	2,446,991	2,478,227
215	881 Rents	7,489	48,470
216	TOTAL Operation (Total of lines 204 thru 215)	15,293,812	15,527,236
217	Maintenance		
218	885 Maintenance Supervision and Engineering	87,244	102,114
219	886 Maintenance of Structures and Improvements	0	
220	887 Maintenance of Mains	2,234,313	2,472,876

Gas Operation and Maintenance Expenses			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
221	888 Maintenance of Compressor Station Equipment	0	
222	889 Maintenance of Measuring and Regulating Station Equipment-General	518,443	739,213
223	890 Maintenance of Meas. and Reg. Station Equipment-Industrial	32,523	55,558
224	891 Maintenance of Meas. and Reg. Station Equip-City Gate Check Station	110,593	233,429
225	892 Maintenance of Services	2,339,341	1,874,030
226	893 Maintenance of Meters and House Regulators	2,967,161	2,966,028
227	894 Maintenance of Other Equipment	332,076	448,151
228	TOTAL Maintenance (Total of lines 218 thru 227)	8,621,694	8,891,399
229	TOTAL Distribution Expenses (Total of lines 216 and 228)	23,915,506	24,418,635
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	158,411	136,117
233	902 Meter Reading Expenses	633,259	935,192
234	903 Customer Records and Collection Expenses	6,776,121	6,893,676
235	904 Uncollectible Accounts	2,506,899	3,283,520
236	905 Miscellaneous Customer Accounts Expenses	85,653	134,095
237	TOTAL Customer Accounts Expenses (Total of lines 232 thru 236)	10,160,343	11,382,600
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
239	Operation		
240	907 Supervision	0	
241	908 Customer Assistance Expenses	13,842,224	13,354,719
242	909 Informational and Instructional Expenses	668,155	975,808
243	910 Miscellaneous Customer Service and Informational Expenses	294,807	295,212
244	TOTAL Customer Service and Information Expenses (Total of lines 240 thru 243)	14,805,186	14,625,739
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	0	
248	912 Demonstrating and Selling Expenses	0	260
249	913 Advertising Expenses	0	550
250	916 Miscellaneous Sales Expenses	0	
251	TOTAL Sales Expenses (Total of lines 247 thru 250)	0	810
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries	13,635,816	11,834,574
255	921 Office Supplies and Expenses	1,778,420	1,807,439
256	(Less) 922 Administrative Expenses Transferred-Credit	18,574	20,135

Gas Operation and Maintenance Expenses			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
257	923 Outside Services Employed	4,875,649	4,513,247
258	924 Property Insurance	704,375	572,070
259	925 Injuries and Damages	1,848,775	1,575,608
260	926 Employee Pensions and Benefits	10,841,938	12,341,599
261	927 Franchise Requirements	0	
262	928 Regulatory Commission Expenses	2,087,312	1,933,458
263	(Less) 929 Duplicate Charges-Credit	0	
264	930.1General Advertising Expenses	5,308	
265	930.2Miscellaneous General Expenses	1,878,650	2,455,255
266	931 Rents	185,705	159,577
267	TOTAL Operation (Total of lines 254 thru 266)	37,823,374	37,172,692
268	Maintenance		
269	932 Maintenance of General Plant	5,247,381	5,057,592
270	TOTAL Administrative and General Expenses (Total of lines 267 and 269)	43,070,755	42,230,284
271	TOTAL Gas O&M Expenses (Total of lines 97,177,201,229,237,244,251, and 270)	323,513,269	299,419,728

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Gas Used in Utility Operations

Line No.	Purpose for Which Gas Was Used (a)	Account Charged (b)	Natural Gas Gas Used Dth (c)	Natural Gas Amount of Credit (in dollars) (d)
1	810 Gas Used for Compressor Station Fuel - Credit		2,283,281	0
2	811 Gas Used for Products Extraction - Credit		[a]41,587,713	1,018,164
3	Gas Shrinkage and Other Usage in Respondent's Own Processing - Credit			
4	Gas Shrinkage, etc. for Respondent's Gas Processed by Others - Credit			
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25	Total		43,870,994	1,018,164

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: QuantityOfNaturalGasDeliveredByRespondentGasUsedForProductsExtraction
Represents the amount of processed gas run through the plant

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Other Gas Supply Expenses (Account 813)

Line No.	Description (a)	Amount (in dollars) (b)
1	Gas Resource Management:	
2	Labor	1,117,522
3	Labor Loading	243,142
4	Other Expenses (Professional Services, Travel, Transportation, Office Supplies, Training)	212,816
5	Regulatory Affairs:	
6	Labor	15,924
7	Labor Loading	3,552
8	Other Expenses (Travel, Transportation, Gas Technology Institute Payments)	171,186
25	Total	1,764,142

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Miscellaneous General Expenses (Account 930.2)

Line No.	Description (a)	Amount (b)
1	Industry association dues.	166,992
2	Experimental and general research expenses	
2a	a. Gas Research Institute (GRI)	
2b	b. Other	
3	Publishing and distributing information and reports to stockholders, trustee, registrar, and transfer agent fees and expenses, and other expenses of servicing outstanding securities of the respondent	293,359
4	Board of Director Activities	641,747
5	Education, Information & Training	121,534
6	Emergency Operating Procedure Events	315,618
7	Community Relations	170,865
8	Misc. Employee Expenses	5,860
9	Misc. Legal, Professional & General Services	62,468
10	Misc. Transportation	92,560
11	Other Misc. Expenses <$5k	7,647
25	TOTAL	1,878,650

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Depreciation, Depletion and Amortization of Gas Plant (Accts 403, 404.1, 404.2, 404.3, 405) (Except Amortization of Acquisition Adjustments)

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization and Depletion of Producing Natural Gas Land and Land Rights (Account 404.1) (d)	Amortization of Underground Storage Land and Land Rights (Account 404.2) (e)
	Section A. Summary of Depreciation, Depletion, and Amortization Charges				
1	Intangible plant				
2	Production plant, manufactured gas				
3	Production and Gathering Plant				
4	Products extraction plant				
5	Underground Gas Storage Plant (footnote details)	[(a)]811,502			
6	Other storage plant				
7	Base load LNG terminaling and processing plant				
8	Transmission Plant				
9	Distribution plant	30,923,984			
10	General Plant (footnote details)	[(b)]1,749,738			
11	Common plant-gas	7,441,571			
12	Total	40,926,795			

Depreciation, Depletion and Amortization of Gas Plant (Accts 403, 404.1, 404.2, 404.3, 405) (Except Amortization of Acquisition Adjustments)			
Line No.	Amortization of Other Limited-term Gas Plant (Account 404.3) (f)	Amortization of Other Gas Plant (Account 405) (g)	Total (b to g) (h)
Section A. Summary of Depreciation, Depletion, and Amortization Charges			
1	133,444		133,444
2			
3			
4			
5			811,502
6			
7			
8			
9			30,923,984
10			1,749,738
11	13,648,363		21,089,934
12	13,781,807		54,708,602

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FOOTNOTE DATA

(a) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments
Totals Plant Accounts 350200 - 357000 for Underground Gas Storage and Plant
(b) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments
Includes Plant Accounts 389200 - 398000 for General Plant plus allocation of DJ 488 AFUDC Reg Asset Amortization.

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Depreciation, Depletion and Amortization of Gas Plant (Accts 403, 404.1, 404.2, 404.3, 405) (Except Amortization of Acquisition Adjustments)

Line No.	Functional Classification (a)	Plant Bases (in thousands) (b)	Applied Depreciation or Amortization Rates (percent) (c)
	Section B. Factors Used in Estimating Depreciation Charges		
1	Production and Gathering Plant		
2	Offshore (footnote details)		
3	Onshore (footnote details)		
4	Underground Gas Storage Plant (footnote details)		
5	Transmission Plant		
6	Offshore (footnote details)		
7	Onshore (footnote details)		
8	General Plant (footnote details)		
9			
10			
11			
12			
13			
14			
15			

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Particulars Concerning Certain Income Deductions and Interest Charges Accounts

Line No.	Item (a)	Amount (b)
1	Account 425 - Miscellaneous Amortization	
2	Items Under $250,000	5,616
3	TOTAL Account 425 - Miscellaneous Amortization	5,616
4	Account 426.1 - Donations	
5	Items Under $250,000	2,499,499
6	TOTAL Account 426.1 - Donations	2,499,499
7	Account 426.2 - Life Insurance	
8	Officers Life	156,937
9	SERP	2,962,146
10	Officers Life Cash Value and Interest, Net	288,428
11	Items Under $250,000	183,987
12	TOTAL Account 426.2 - Life Insurance	3,591,498
13	Account 426.3 - Penalties	
14	Items Under $250,000	22,039
15	TOTAL Account 426.3 - Penalties	22,039
16	Account 426.4 Expenditures for Certain Civic, Political, and Related Activities	
17	Partners for Energy Progress	270,000
18	Items Under $250,000	1,665,266
19	Total Account 426.4 - Expenditues for Certain Civic, Political, and Related Activities	1,935,266
20	Account 426.5 - Other Deductions	
21	Executive Deferred Compensation	1,160,797
22	Hanna & Associates (Advertising)	423,528
23	Items Under $250,000	2,864,633
24	TOTAL Account 426.5 - Other Deductions	4,448,958
25	Account 430 - Interest on Debt to Associated Companies	
26	Items Under $250,000	94,569
27	Avista Capital II (long-term debt) (variable rate ranged from 0.99 to 1.10 percent)	420,878
28	TOTAL Account 430 - Interest on Debt to Associated Companies	515,447
29	Account 431 - Other Interest Expense	
30	Interest on electric deferrals	1,296,417
31	Interest on natural gas deferrals	174,394
32	Interest on committed line of credit	3,308,861
33	Items Under $250,000	80,383
34	TOTAL Account 431 - Other Interest Expense	4,860,055

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Regulatory Commission Expenses (Account 928)

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 to Date (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Federal Energy Regulatory Commission - Charges include annual fee and license fees for the Spokane River Project, the Cabinet Gorge Project and the Noxon Rapids Project	3,012,871	187,113	3,199,984	
2	Washington Utilities and Transportation Commission			0	
3	Electric - Includes annual fee and various other electric dockets	1,083,148	952,811	2,035,959	
4	Gas - Includes annual fee and various other natural gas dockets	319,906	200,524	520,430	
5	Idaho Public Utilities Commission			0	
6	Electric - Includes annual fee and various other electric dockets	521,315	248,972	770,287	
7	Gas - Includes annual fee and various other natural gas dockets	128,397	77,144	205,541	
8	Public Utility Commission of Oregon			0	
9	Includes annual fees and various other natural gas dockets	644,573	430,479	1,075,052	59,519
10	Not directly assigned Electric		675,110	675,110	
11	Not directly assigned Natural Gas		286,289	286,289	
25	TOTAL	5,710,210	3,058,442	8,768,652	59,519

Regulatory Commission Expenses (Account 928)					
Line No.	Expenses Incurred During Year Charged Currently To Department (f)	Expenses Incurred During Year Charged Currently To Account No. (g)	Expenses Incurred During Year Charged Currently To Amount (h)	Expenses Incurred During Year Deferred to Account 182.3 (i)	Amortized During Year Contra Account (j)
1	Electric	928	3,199,983		
2					
3	Electric	928	2,035,959		
4	Gas	928	520,430		
5					
6	Electric	928	770,288		
7	Gas	928	205,541		
8					
9	Gas	928	1,075,052	34,567	407
10	Electric	928	675,110		
11	Gas	928	286,289		
25			8,768,652	34,567	

Regulatory Commission Expenses (Account 928)		
Line No.	Amortized During Year Amount (k)	Deferred in Account 182.3 End of Year (l)
1		0
2		0
3		0
4		0
5		0
6		0
7		0
8		0
9	67,777	26,309
10		0
11		0
25	67,777	26,309

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Employee Pensions and Benefits (Account 926)

Line No.	Expense (a)	Amount (in dollars) (b)
1	Pensions - defined benefit plans	16,795,430
2	Pensions - other	
3	Post-retirement benefits other than pensions (PBOP)	9,357,563
4	Post-employment benefit plans	
5	Other (Specify)	246,164
6	Health Insurance and Benefits	29,505,049
7	401(K) Savings Plan	11,670,678
8	Employee Education	875,828
9	Allocated to Electric	(57,608,774)
40	Total	10,841,938

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Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Distribution of Salaries and Wages

Line No.	Classification (a)	Direct Payroll Distribution (b)	Payroll Billed by Affiliated Companies (c)	Allocation of Payroll Charged for Clearing Accounts (d)	Total (e)
1	Electric				
2	Operation				
3	Production	13,568,766			13,568,766
4	Transmission	4,739,365			4,739,365
5	Distribution	10,274,320			10,274,320
6	Customer Accounts	5,840,091			5,840,091
7	Customer Service and Informational	371,441			371,441
8	Sales				
9	Administrative and General	25,718,437			25,718,437
10	TOTAL Operation (Total of lines 3 thru 9)	60,512,420			60,512,420
11	Maintenance				
12	Production	5,177,241			5,177,241
13	Transmission	1,173,286			1,173,286
14	Distribution	5,708,075			5,708,075
15	Administrative and General			6,461,523	6,461,523
16	TOTAL Maintenance (Total of lines 12 thru 15)	12,058,602		6,461,523	18,520,125
17	Total Operation and Maintenance				
18	Production (Total of lines 3 and 12)	18,746,007			18,746,007
19	Transmission (Total of lines 4 and 13)	5,912,651			5,912,651
20	Distribution (Total of lines 5 and 14)	15,982,395		0	15,982,395
21	Customer Accounts (line 6)	5,840,091			5,840,091
22	Customer Service and Informational (line 7)	371,441			371,441
23	Sales (line 8)				
24	Administrative and General (Total of lines 9 and 15)	25,718,437		6,461,523	32,179,960
25	TOTAL Operation and Maintenance (Total of lines 18 thru 24)	72,571,022		6,461,523	79,032,545
26	Gas				
27	Operation				
28	Production - Manufactured Gas				
29	Production - Natural Gas(Including Exploration and Development)				
30	Other Gas Supply	1,133,446			1,133,446
31	Storage, LNG Terminaling and Processing	3,436			3,436
32	Transmission				0

Distribution of Salaries and Wages					
Line No.	Classification (a)	Direct Payroll Distribution (b)	Payroll Billed by Affiliated Companies (c)	Allocation of Payroll Charged for Clearing Accounts (d)	Total (e)
33	Distribution	5,919,606			5,919,606
34	Customer Accounts	2,646,571			2,646,571
35	Customer Service and Informational	240,643			240,643
36	Sales				
37	Administrative and General	10,562,731		1,365,111	11,927,842
38	TOTAL Operation (Total of lines 28 thru 37)	20,506,433		1,365,111	21,871,544
39	Maintenance				
40	Production - Manufactured Gas				
41	Production - Natural Gas(Including Exploration and Development)				
42	Other Gas Supply				0
43	Storage, LNG Terminaling and Processing				0
44	Transmission	1,808,742			1,808,742
45	Distribution	3,268,997			3,268,997
46	Administrative and General				0
47	TOTAL Maintenance (Total of lines 40 thru 46)	5,077,739			5,077,739
49	Total Operation and Maintenance				
50	Production - Manufactured Gas (Total of lines 28 and 40)				
51	Production - Natural Gas (Including Expl. and Dev.)(ll. 29 and 41)				
52	Other Gas Supply (Total of lines 30 and 42)	1,133,446			1,133,446
53	Storage, LNG Terminaling and Processing (Total of ll. 31 and 43)	3,436			3,436
54	Transmission (Total of lines 32 and 44)	1,808,742			1,808,742
55	Distribution (Total of lines 33 and 45)	9,188,603			9,188,603
56	Customer Accounts (Total of line 34)	2,646,571			2,646,571
57	Customer Service and Informational (Total of line 35)	240,643			240,643
58	Sales (Total of line 36)				
59	Administrative and General (Total of lines 37 and 46)	10,562,731		1,365,111	11,927,842
60	Total Operation and Maintenance (Total of lines 50 thru 59)	25,584,172		1,365,111	26,949,283
61	Other Utility Departments				
62	Operation and Maintenance				0
63	TOTAL ALL Utility Dept. (Total of lines 25, 60, and 62)	98,155,194		7,826,634	105,981,828
64	Utility Plant				
65	Construction (By Utility Departments)				

Distribution of Salaries and Wages					
Line No.	Classification (a)	Direct Payroll Distribution (b)	Payroll Billed by Affiliated Companies (c)	Allocation of Payroll Charged for Clearing Accounts (d)	Total (e)
66	Electric Plant	45,200,050		5,321,807	50,521,857
67	Gas Plant	14,348,191		1,689,342	16,037,533
68	Other				0
69	TOTAL Construction (Total of lines 66 thru 68)	59,548,241	0	7,011,149	66,559,390
70	Plant Removal (By Utility Departments)				
71	Electric Plant	2,037,150		98,219	2,135,369
72	Gas Plant	552,595		26,644	579,239
73	Other				0
74	TOTAL Plant Removal (Total of lines 71 thru 73)	2,589,745		124,863	2,714,608
75.1	Stores Expense (163)	2,589,304		(2,589,304)	0
75.2	Preliminary Survey and Investigation (183)	0			0
75.3	Small Tool Expense (184)	4,644,702		(4,644,702)	0
75.4	Miscellaneous Deferred Debits (186)	1,216,883			1,216,883
75.5	Non-operating Expenses (417)	267,369			267,369
75.6	Retirement Bonus/SERP/HRA (228)	117,285			117,285
75.7	Other Income Deductions (426)	1,031,477			1,031,477
75.8	Employee Incentive Plan (232380)	5,777,825		(5,777,825)	0
75.9	DSM Tariff Rider (242600)	1,950,815		(1,950,815)	0
75.10	Incentive/Stock Compensation (238000)	395,932			395,932
75.11	Payroll Equalization Liability (242700)	25,041,157			25,041,157
76	TOTAL Other Accounts	43,032,749	0	(14,962,646)	28,070,103
77	TOTAL SALARIES AND WAGES	203,325,929	0	0	203,325,929

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Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Charges for Outside Professional and Other Consultative Services

Line No.	Description (a)	Amount (in dollars) (b)
1	NPL CONSTRUCTION CO	21,596,086
2	VOLT MANAGEMENT CORP	17,789,586
3	WILSON CONSTRUCTION COMPANY	14,230,349
4	SLAYDEN CONSTRUCTORS INC	11,462,292
5	ASPLUNDH TREE EXPERT LLC	10,594,433
6	STURGEON ELECTRIC INC	9,868,463
7	INTERNATIONAL LINE BUILDERS INC	9,737,350
8	POTELCO INC	8,061,452
9	MICHELS UTILITY SERVICES INC	7,937,073
10	GREENBERRY INDUCTRIAL LLC	6,157,010
11	SIEMENS ENERGY INC	5,509,356
12	ONE CALL LOCATORS LTD	4,737,545
13	MICHELS CORPORATION	4,267,318
14	CASCADE CABLE CONSTRUCTORS INC	3,665,514
15	INFRASOURCE SERVICES LLC	3,070,374
16	WSP USA INC	3,016,098
17	PERFECTION TRAFFIC CONTROL LLC	2,752,433
18	IBM CORPORATION	2,602,693
19	PALOUSE POWER LLC	2,599,347
20	NAGARRO INC	2,551,957
21	TITAN ELECTRIC INC	2,434,579
22	PRYSMIAN CABLES AND SYSTEMS USA LLC	2,377,899
23	WRIGHT TREE SERVICE LLC	2,201,017
24	TRAFFICORP	2,158,207
25	LAND EXPRESSIONS	2,158,182
26	MICHELS PACIFIC ENERGY INC	2,158,157
27	HEATH CONSULTANTS INCORPORATED	2,054,866
28	MCMILLEN JACOBS ASSOCIATES	2,027,892
29	POWER CITY ELECTRIC INC	1,924,090
30	INTELLITECT	1,826,343
31	DELLOITTE	1,773,900
32	UTILICAST LLC	1,754,159
33	POWER ENGINEERS INC	1,585,562
34	TRAFFIC CONTROL SERVICES LLC	1,513,979
35	TECHNIBUS INC	1,435,014

Charges for Outside Professional and Other Consultative Services		
Line No.	Description (a)	Amount (in dollars) (b)
36	UTILITY SOLUTIONS PARTNERS LLC	1,416,330
37	KNIGHT CONSTRUCTION & SUPPLY INC	1,406,449
38	SUNRISE ENGINEERING INC	1,368,381
39	PER SE GROUP INC	1,284,057
40	UTILITY CONTRUSTION INSPECTION LLC	1,221,449
41	CURRY INC	1,211,574
42	POE ASPHALT PAVING INC	1,195,875
43	GE RENEWABLES US LLC	1,194,972
44	COMMERCIAL GRADING INC	1,177,514
45	RESSA & SON CONSTRUCTION LLC	1,142,534
46	STANTEC CONSULTING SERVICES INC	1,108,607
47	SPOKANE TRAFFIC CONTROL INC	1,065,712
48	FUJITSU AMERICA IN	1,049,231
49	CN UTILITY CONSULTING INC	996,145
50	SINISI SOLUTIONS LLC	986,888
51	POWER SYSTEMS CONSULTANTS INC	977,711
52	BRENT WOODWARD INC	952,873
53	WELLINGTON ENERGY INC	939,862
54	WALKER INDUSTRIES LLC	937,347
55	NUVODIA STAFFING LLC	925,622
56	AAA SWEEPING LLC	915,209
57	IDAHO FENCE	906,521
58	INTEC SERVICES INC	847,561
59	COMMONWEALTH ASSOCIATES INC	819,295
60	MESA PRODUCTS INC	756,186
61	HYDROMAX USA LLC	742,764
62	D W POLEHOLE	692,336
63	COEUR D ALENE TRIBE	677,426
64	GEODIGITAL INTERNATIONAL CORP	649,565
65	GARCO CONSTRUCTION INC	620,116
66	NOVTECH	616,487
67	POWER COSTS INC	615,766
68	DXC TECHNOLOGY SERVICES LLC	615,381
69	UTILITY GUYS INC	611,538
70	IDAGON HOMES LLC	595,727
71	TIER1 INC	577,084
72	LYDIG CONSTRUCTION INC	569,661
73	HATTENBURG EXCAVATING	539,727

Charges for Outside Professional and Other Consultative Services		
Line No.	Description (a)	Amount (in dollars) (b)
74	MCKINSTRY ESSNTION LLC	537,288
75	CRUX SUBSURFACE INC	532,537
76	NUVODIA LLC	529,526
77	BOYER LAND DEVELOPMENT INC	527,511
78	ALDEN RESEARCH LABORATORY INC	509,978
79	CERIUM NETWORKS	508,179
80	JENSENS TREE SERVICE INC	507,233
81	STATEFIRE DC SPECIALITIES	493,501
82	NEAL STRUCTURAL REPAIR LLC	450,111
83	PROFESSIONAL PIPE SERVICES	426,433
84	SCHNABEL ENGINEERING LLC	406,297
85	BLACK & VEATCH CORPORATION	403,648
86	IDAHO DEPT OF FISH & GAME	391,031
87	MCKINSTRY COMPANY LLC	389,250
88	HICKEY BROTHERS RESEARCH LLC	388,232
89	NORTHWEST POWER POOL	386,537
90	AVCO CONSULTING INC	361,352
91	IDAHO POWER CO	354,581
92	GEOENGINEERS INC	350,725
93	PACIFICORP	348,519
94	BOUTEN CONSTRUCTION COMPANY	347,482
95	HELVETICKA INC	337,202
96	STRATA	334,010
97	SUMMIT UTILITY CONTRACTORS LLC	331,176
98	NORTH AMERICAN SUBSTATION SERVICES LLC	325,435
99	CIRRUS DESIGN INDUSTRIES INC	324,095
100	HDR ENGINEERING INC	323,240
101	FOUST FABRICATION CO	318,440
102	NOBLE EXCAVATING INC	302,000
103	ELECTRICAL CONSULTANTS INC	298,920
104	POWER PLAN INC	288,427
105	COLVICO INC	288,126
106	CREEDENCE CLEARWATER INDUSTRIAL INC	287,112
107	HANNA & ASSOCIATES INC	284,838
108	HEAD CONCRETE INC	280,690
109	TAILORED SOLUTIONS LLC	280,549
110	HANSBERRY & JOURDONNAIS PPLC	277,183

Charges for Outside Professional and Other Consultative Services		
Line No.	Description (a)	Amount (in dollars) (b)
111	ALDRIDGE ELECTRIC INC	274,982
112	NOKIA OF AMERICA CORPORATION	273,148
113	RANDALL DANSKIN ATTORNEYS	270,020
114	CASNE ENGINEERING INC	265,843
115	AIRDASH INC	260,000
116	CACHE VALLEY ELECTRIC	256,448
117	JK CONCRETE & EXCAVATION LLC	252,904
118	OTHER >$250,000	25,532,128
119	TOTAL	257,934,925

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Transactions with Associated (Affiliated) Companies

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	Goods or Services Provided by Affiliated Company			
2	Non-Power Goods or Services	Steam Plant Square	931000	64,790
19	TOTAL			64,790
20	Goods or Services Provided for Affiliated Company			
21	Corporate Support	Salix, Inc.	146000	108,342
22	Corporate Support	Avista Development	146000	166,272
23	Corporate Support	Avista Capital	146000	85,236
24	Corporate Support	AELP	146000	20,045
25	Corporate Support	AJT Mining	146000	2,586
26	Corporate Support	Avista Edge	146000	364,365
40	TOTAL			746,846

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Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Gas Storage Projects

Line No.	Item (a)	Gas Belonging to Respondent (Dth) (b)	Gas Belonging to Others (Dth) (c)	Total Amount (Dth) (d)
	STORAGE OPERATIONS (in Dth)			
1	Gas Delivered to Storage			
2	January	162,761		162,761
3	February	0		0
4	March	20,372		20,372
5	April	931,861		931,861
6	May	3,046,310		3,046,310
7	June	2,553,163		2,553,163
8	July	928,670		928,670
9	August	253,649		253,649
10	September	50,153		50,153
11	October	273,825		273,825
12	November	302,791		302,791
13	December	132,914		132,914
14	TOTAL (Total of lines 2 thru 13)	8,656,469	0	8,656,469
15	Gas Withdrawn from Storage			
16	January	1,169,883		1,169,883
17	February	2,116,968		2,116,968
18	March	1,614,371		1,614,371
19	April	202,329		202,329
20	May	2,916		2,916
21	June	1,176		1,176
22	July	4,373		4,373
23	August	49,838		49,838
24	September	63,834		63,834
25	October	346,344		346,344
26	November	627,713		627,713
27	December	2,366,392		2,366,392
28	TOTAL (Total of lines 16 thru 27)	8,566,137	0	8,566,137

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Gas Storage Projects

Line No.	Item (a)	Total Amount (b)
	STORAGE OPERATIONS	
1	Top or Working Gas End of Year	8,528,000
2	Cushion Gas (Including Native Gas)	7,730,668
3	Total Gas in Reservoir (Total of line 1 and 2)	16,258,668
4	Certificated Storage Capacity	
5	Number of Injection - Withdrawal Wells	50
6	Number of Observation Wells	32
7	Maximum Days' Withdrawal from Storage	[(a)]137,366
8	Date of Maximum Days' Withdrawal	02/11/2021
9	LNG Terminal Companies (in Dth)	
10	Number of Tanks	
11	Capacity of Tanks	
12	LNG Volume	
13	Received at "Ship Rail"	
14	Transferred to Tanks	
15	Withdrawn from Tanks	
16	"Boil Off" Vaporization Loss	

FOOTNOTE DATA

(a) Concept: MaximumDaysWithdrawalFromStorage
Mcf converted to Dth using a factor of 1.0400

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Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Auxiliary Peaking Facilities

Line No.	Location of Facility (a)	Type of Facility (b)	Maximum Daily Delivery Capacity of Facility Dth (c)	Cost of Facility (in dollars) (d)	Was Facility Operated on Day of Highest Transmission Peak Delivery? (e)
1	Chehalis, Washington	Underground Natural Gas Storage Field Washington & Idaho Supply	346,667	48,468,752	true
2	Chehalis, Washington	Underground Natural Gas Storage Field Oregon Supply	52,000	7,268,282	true
3	(a) Chehalis, Washington	Underground Natural Gas Storage Field Oregon Supply	2,623		true
4	(b) Rock Springs, Wyoming	Underground Natural Gas Storage Field Washington & Idaho Supply			true
5	(c) Rock Springs, Wyoming	Underground Natural Gas Storage Field Oregon Supply			true

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: LocationOrNameOfFacility
Avista is a participant in the facilities, not an owner and is charged a fee for demand deliverability and capacity.
(b) Concept: LocationOrNameOfFacility
Avista does not have firm rights but have interruptible access to it.
(c) Concept: LocationOrNameOfFacility
Avista does not have firm rights but have interruptible access to it.

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Gas Account - Natural Gas

Line No.	Item (a)	Ref. Page No. of (FERC Form Nos. 2/2-A) (b)	Total Amount of Dth Year to Date (c)	Current Three Months Ended Amount of Dth Quarterly Only (d)
1	Name of System	Avista Storage		
2	GAS RECEIVED			
3	Gas Purchases (Accounts 800-805)		75,118,570	20,630,032
4	Gas of Others Received for Gathering (Account 489.1)	303		
5	Gas of Others Received for Transmission (Account 489.2)	305		
6	Gas of Others Received for Distribution (Account 489.3)	301	17,901,306	5,230,833
7	Gas of Others Received for Contract Storage (Account 489.4)	307		
8	Gas of Others Received for Production/Extraction/Processing (Account 490 and 491)			
9	Exchanged Gas Received from Others (Account 806)	328	119,546	75,886
10	Gas Received as Imbalances (Account 806)	328		
11	Receipts of Respondent's Gas Transported by Others (Account 858)	332		
12	Other Gas Withdrawn from Storage (Explain)		(135,220)	2,595,060
13	Gas Received from Shippers as Compressor Station Fuel			
14	Gas Received from Shippers as Lost and Unaccounted for			
15	Other Receipts (Specify) (footnote details)			
16	Total Receipts (Total of lines 3 thru 15)		93,004,202	28,531,811
17	GAS DELIVERED			
18	Gas Sales (Accounts 480-484)		73,494,954	22,557,605
19	Deliveries of Gas Gathered for Others (Account 489.1)	303		
20	Deliveries of Gas Transported for Others (Account 489.2)	305		
21	Deliveries of Gas Distributed for Others (Account 489.3)	301	17,225,967	5,038,155
22	Deliveries of Contract Storage Gas (Account 489.4)	307		
23	Gas of Others Delivered for Production/Extraction/Processing (Account 490 and 491)			
24	Exchange Gas Delivered to Others (Account 806)	328		
25	Gas Delivered as Imbalances (Account 806)	328		
26	Deliveries of Gas to Others for Transportation (Account 858)	332		

Gas Account - Natural Gas				
Line No.	Item (a)	Ref. Page No. of (FERC Form Nos. 2/2-A) (b)	Total Amount of Dth Year to Date (c)	Current Three Months Ended Amount of Dth Quarterly Only (d)
27	Other Gas Delivered to Storage (Explain)			
28	Gas Used for Compressor Station Fuel	509	2,283,281	936,051
29	Other Deliveries and Gas Used for Other Operations			
30	Total Deliveries (Total of lines 18 thru 29)		93,004,202	28,531,811
31	GAS LOSSES AND GAS UNACCOUNTED FOR			
32	Gas Losses and Gas Unaccounted For			
33	TOTALS			
34	Total Deliveries, Gas Losses & Unaccounted For (Total of lines 30 and 32)		93,004,202	28,531,811

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(*M, D, Y*) May 1, 2022	Dec. 31, 2021

STATE OF OREGON - STATEMENT OF OPERATING INCOME FOR THE YEAR

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	2	$161,312,114	$138,266,166
3	Operating Expenses			
4	Operation Expenses (401)	4 - 9	108,637,328	93,739,801
5	Maintenance Expenses (402)	4 - 9	4,697,683	4,918,110
6	Depreciation Expense (403)	10	12,274,205	11,849,100
7	Amort. & Depl. of Utility Plant (404-405)	10	3,960,991	3,336,889
8	Amort. of Utility Plant Acq. Adj. (406)(See Note 1)	10		
9	Amort. of Property Losses, Unrecovered Plant and Regulatory Study Costs (407)			
10	Senate Bill 408 (407330/407408/407431)		0	0
11	Reg Debit/Credit ()		(252,599)	(4,643,706)
12	Taxes Other Than Income Taxes (408.1)	11	9,750,074	9,043,923
13	Income Taxes - Federal (409.1)	12	(1,737,848)	(2,311,970)
14	- Other (409.1)	13	845,139	870,030
15	Provision for Deferred Income Taxes (410.1) (410.2)	14 - 21	5,145,263	3,728,925
16	(Less) Prov. for Def. Inc. Taxes-Cr. (411.1)	14 - 21	1,528,632	150,805
17	Investment Tax Credit Adj. - Net (411.4)	22		
18	(Less) Gains from Disp. of Utility Plant (411.7)			
19	Losses from Disp. of Utility Plant (411.7)			
20	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 18)		141,791,604	120,380,297
21	Net Utility Operating Income Enter Total of Line 2 less Line 19		$19,520,510	$17,885,869

Name of Respondent	This Report Is:	Date of Report (M, Y, D)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - GAS OPERATING REVENUES (Account 400)

Line No.	Title of Account (a)	OPERATING REVENUES Current Year (b)	OPERATING REVENUES Previous Year (c)	THERMS OF GAS SOLD Current Year (d)	THERMS OF GAS SOLD Previous Year (e)	AVG. NO. OF GAS CUST. PER MO. Current Year (f)	AVG. NO. OF GAS CUST. PER MO. Previous Year (g)	Line No.
1	GAS SERVICE REVENUES							1
2	(480) Residential Sales	66,850,834	62,561,977	50,565,481 **	50,584,132	92,971	92,304	2
3	(481) Commercial and Industrial Sales							3
4	Small (or Comm.) (See Instr. 6)	33,445,298	29,927,973	35,443,613 **	34,377,175	11,955	11,951	4
5	Large (or Ind.) (See Instr. 6)	3,508,813	2,956,915	11,813,343 **	10,239,201	47	43	5
6	(482) Other Sales to Public Authorities							6
7	(484) Interdepartmental Sales	17,928	14,455	16,023	13,683	11	11	7
8	TOTAL Sales to Ultimate Consumers	103,822,873 *	95,461,320	97,838,460 **	95,214,191	104,983	104,308	8
9	(483) Sales for Resale	50,061,389	40,864,451	142,233,710	221,089,330			9
10	TOTAL Nat. Gas Service Revenues	153,884,262	136,325,771	240,072,170	316,303,521	104,983	104,308	10
11	Revenues from Manufactured Gas			0	-	-	-	11
12	TOTAL Gas Service Revenues	153,884,262	136,325,771					12
13	OTHER OPERATING REVENUES							13
14	(485) Intracompany Transfers							14
15	(487) Forfeited Discounts							15
16	(488) Misc. Service Revenues	21,110	36,130					16
17	(489) Rev. from Trans. of Gas of Others	2,984,984 *	2,671,853					17
18	(490) Sales of Prod. Ext. from Nat. Gas							18
19	(491) Rev. from Nat. Gas Proc. by Others							19
20	(492) Incidental Gasoline and Oil Sales							20
21	(493) Rent from Gas Property	13,000	0					21
22	(494) Interdepartmental Rents							22
23	(495) Other Gas Revenues	4,408,757	(373,404)					23
24	TOTAL Other Operating Revenues	7,427,851	2,334,579					24
25	TOTAL Gas Operating Revenues	161,312,113	138,660,350					25
26	(Less) (496) Provision for Rate Refunds	0	(394,184)					26
27	TOTAL Gas Operating Revenues Net of Provision for Refunds	161,312,113						27
28	Dis. Type Sales by States (Incl. Main Line Sales to Resid. and Comm. Custrs.)	100,296,132		86,009,094				28
29	Main Line Industrial Sales (Incl. Main Line Sales to Pub. Authorities)	3,508,813		11,813,343				29
30	Sales for Resale	50,061,389		142,233,710				30
31	Other Sales to Pub. Auth. (Local Dist. Only)							31
32	Interdepartmental Sales	17,928		16,023				32
33	TOTAL (Same as Line 10, Columns (b) and (d))	153,884,262		240,072,170				33

Notes:

* Includes unbilled revenues

** Includes unbilled therms

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - INTERDEPARTMENTAL SALES - NATURAL GAS (Account 484)

Report particulars concerning sales of natural gas included in Account 484

Line No.	Department and Basis of Charges (a)	Point of Delivery (b)	Mcf (14.73 psia at 60• F) (c)	Revenue (d)
1				
2				
3	Natural gas supply for operation	Avista facility	1,545	17,928
4	of Avista's facilities			
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	TOTAL		1,545	17,928

RENT FROM GAS PROPERTY AND INTERDEPARTMENTAL RENTS (Accounts 493 and 494)

1. Report particulars concerning rents received included in Accounts 493 and 494.
2. Minor rents may be entered at the total amount for each class of such rents.
3. If rents are included which were arrived at under an arrangement for apportioning expenses of a joint facility, whereby the amount included in this account represents profit or return on property, depreciation, and taxes, give particulars and the basis of apportionment of such charges to Account 493 or 494.
4. Provide a subheading and total for each account.

Line No.	Name of Lessee or Department (Designate associated companies) (a)	Description of property (b)	Amount of Revenue for Year	
			Natural Gas Property (c)	Manufactured Gas Property (d)
1				
2				
3	Other		13,000	
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19	TOTAL		13,000	

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) May 1, 2022	Dec. 31, 2021

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Amount *(a)*	Amount for Current Year *(b)*	Amount for Previous Year *(c)*
1	1. PRODUCTION EXPENSES		
2	A. Manufactured Gas Production	-	-
3	Manufactured Gas Production (Submit Supplemental Statement)		
4	B. Natural Gas Production		
5	B1. Natural Gas Production and Gathering		
6	Operation	-	-
7	750 Operation Supervision and Engineering	-	-
8	751 Production Maps and Records	-	-
9	752 Gas Wells Expenses	-	-
10	753 Field Lines Expenses	-	-
11	754 Field Compressor Station Expenses	-	-
12	755 Field Compressor Station Fuel and Power	-	-
13	756 Field Measuring and Regulating Station Expenses	-	-
14	757 Purification Expenses	-	-
15	758 Gas Well Royalties	-	-
16	759 Other Expenses	-	-
17	760 Rents	-	-
18	TOTAL Operation (Enter Total of lines 7 thru 17)	-	-
19	Maintenance		
20	761 Maintenance Supervision and Engineering	-	-
21	762 Maintenance of Structures and Improvements	-	-
22	763 Maintenance of Producing Gas Wells	-	-
23	764 Maintenance of Field Lines	-	-
24	765 Maintenance of Field Compressor Station Equipment	-	-
25	766 Maintenance of Field Meas. and Reg. Sta. Equipment	-	-
26	767 Maintenance of Purification Equipment	-	-
27	768 Maintenance of Drilling and Cleaning Equipment	-	-
28	769 Maintenance of Other Equipment	-	-
29	TOTAL Maintenance (Enter Total of lines 20 thru 28)	-	-
30	TOTAL Natural Gas Production and Gathering (Total of lines 18 and 29)	-	-
31	B2. Products Extraction		
32	Operation		
33	770 Operation Supervision and Engineering	-	-
34	771 Operation Labor	-	-
35	772 Gas Shrinkage	-	-
36	773 Fuel	-	-
37	774 Power	-	-
38	775 Materials	-	-
39	776 Operation Supplies and Expenses	-	-
40	777 Gas Processed by Others	-	-
41	778 Royalties on Products Extracted	-	-
42	779 Marketing Expenses	-	-
43	780 Products Purchased for Resale	-	-
44	781 Variation in Products Inventory	-	-
45	(Less) 782 Extracted Products Used by the Utility-Credit	-	-
46	783 Rents	-	-
47	TOTAL Operation (Enter Total of Lines 33 thru 46)	-	-

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STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

Line No.	Amount *(a)*	Amount for Current Year *(b)*	Amount for Previous Year *(c)*
	B2. Products Extraction (Continued)		
48	Maintenance		
49	784 Maintenance Supervision and Engineering	-	-
50	785 Maintenance of Structures and Improvements	-	-
51	786 Maintenance of Extraction and Refining Equipment	-	-
52	787 Maintenance of Pipe Lines	-	-
53	788 Maintenance of Extracted Products Storage Equipment	-	-
54	789 Maintenance of Compressor Equipment	-	-
55	790 Maintenance of Gas Measuring and Reg. Equipment	-	-
56	791 Maintenance of Other Equipment	-	-
57	TOTAL Maintenance (Enter Total of lines 49 thru 56)	-	-
58	TOTAL Products Extraction (Enter Total of lines 47 and 57)	-	-
59	C. Exploration and Development		
60	Operation		
61	795 Delay Rentals	-	-
62	796 Nonproductive Well Drilling	-	-
63	797 Abandoned Leases	-	-
64	798 Other Exploration	-	-
65	TOTAL Exploration and Development (Enter Total of lines 61 thru 64)	-	-
	D. Other Gas Supply Expenses		
66	Operation		
67	800 Natural Gas Well Head Purchases	-	-
68	800.1 Natural Gas Well Head Purchases, Intracompany Transfers	-	-
69	801 Natural Gas Field Line Purchases	-	-
70	802 Natural Gas Gasoline Plant Outlet Pruchases	-	-
71	803 Natural Gas Transmission Line Purchases	-	-
72	804 Natural Gas City Gate Purchases	86,604,199	68,759,761
73	804.1 Liquefied Natural Gas Purchases	-	-
74	805 Other Gas Purchases	-	-
75	(Less) 805.1 Purchased Gas Cost Adjustments	(2,060,286)	(306,092)
76			
77	TOTAL Purchased Gas (Enter Total of lines 67 to 76)	84,543,913	68,453,669
78	806 Exchange Gas		-
79	Purchased Gas Expenses		
80	807.1 Well Expenses-Purchased Gas		-
81	807.2 Operation of Purchased Gas Measuring Stations		-
82	807.3 Maintenance of Purchased Gas Measuring Stations		-
83	807.4 Purchased Gas Calculations Expenses		-
84	807.5 Other Purchased Gas Expenses		-
85	TOTAL Purchased Gas Expenses (Enter Total of lines 80 thru 84)		-
86	808.1 Gas Withdrawn from Storage-Debit	-	1,875,642
87	(Less) 808.2 Gas Delivered to Storage-Credit	(870,936)	(1,382,919)
88	809.1 Withdrawals of Liquefied Natural Gas for Processing-Debit	-	-
89	(Less) 809.2 Deliveries of Natural Gas for Processing-Credit	-	-
90	Gas Used in Utility Operations-Credit		
91	810 Gas Used for Compressor Station Fuel-Credit	-	-
92	811 Gas Used for Products Extraction-Credit	(356,232)	(94,949)
93	812 Gas used for Other Utility Operations-Credit	-	-
94	TOTAL Gas Used in Utility Operations-Credit (Total of lines 91 thru 93)	(356,232)	(94,949)
95	813 Other Gas Supply Expenses	628,804	512,680
96	TOTAL Other Gas Supply Exp (Total of lines 77,78,85,86 thru 89,94,95)	83,945,549	69,364,123
97	TOTAL Production Expenses (Enter Total of lines 3,30,58,65, and 96)	83,945,549	69,364,123

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) May 1, 2022	Dec. 31, 2021

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

Line No.	Amount *(a)*	Amount for Current Year *(b)*	Amount for Previous Year *(c)*
98	2. NATURAL GAS STORAGE, TERMINALING AND PROCESSING EXPENSES		
99	A. Underground Storage Expenses		
100	Operation		
101	814 Operation Supervision and Engineering	-	-
102	815 Maps and Records	-	-
103	816 Wells Expenses	-	-
104	817 Lines Expense	-	-
105	818 Compressor Station Expenses	-	-
106	819 Compressor Station Fuel and Power	-	-
107	820 Measuring and Regulating Station Expenses	-	-
108	821 Purification Expenses	-	-
109	822 Exploration and Development	-	-
110	823 Gas Losses	-	-
111	824 Other Expenses	85,830	77,760
112	825 Storage Well Royalties	-	-
113	826 Rents	-	-
114	TOTAL Operation (Enter Total of lines 101 thru 113)	85,830	77,760
115	Maintenance		
116	830 Maintenance Supervision and Engineering	-	-
117	831 Maintenance of Structures and Improvements	-	-
118	832 Maintenance of Reservoirs and Wells	-	-
119	833 Maintenance of Lines	-	-
120	834 Maintenance of Compressor Station Equipment	-	-
121	835 Maintenance of Measuring and Regulating Station Equipment	-	-
122	836 Maintenance of Purification Equipment	-	-
123	837 Maintenance of Other Equipment	202,571	210,953
124	TOTAL Maintenance (Enter Total of lines 116 thru 123)	202,571	210,953
125	TOTAL Underground Storage Expenses (Total of lines 114 and 124)	288,401	288,713
126	B. Other Storage Expenses		
127	Operation		
128	840 Operation Supervision and Engineering	-	-
129	841 Operation Labor and Expenses	-	-
130	842 Rents	-	-
131	842.1 Fuel	-	-
132	842.2 Power	-	-
133	842.3 Gas Losses	-	-
134	TOTAL Operation (Enter Total of lines 128 thru 133)	-	-
135	Maintenance		
136	843.1 Maintenance Supervision and Engineering	-	-
137	843.2 Maintenance of Structures and Improvements	-	-
138	843.3 Maintenance of Gas Holders	-	-
139	843.4 Maintenance of Purification Equipment	-	-
140	843.5 Maintenance of Liquefaction Equipment	-	-
141	843.6 Maintenance of Vaporizing Equipment	-	-
142	843.7 Maintenance of Compressor Equipment	-	-
143	843.8 Maintenance of Measuring and Regulating Equipment	-	-
144	843.9 Maintenance of Other Equipment	-	-
145	TOTAL Maintenance (Enter Total of lines 136 thru 144)	-	-
146	TOTAL Other Storage Expenses (Enter Total of lines 134 and 145)	-	-

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STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

Line No.	Amount *(a)*	Amount for Current Year *(b)*	Amount for Previous Year *(c)*
147	C. Liquefied Natural Gas Terminaling and Processing Expenses		
148	Operation		
149	844.1 Operation Supervision and Engineering	-	-
150	844.2 LNG Processing Terminal Labor and Expenses	-	-
151	844.3 Liquefaction Processing Labor and Expenses	-	-
152	844.4 Liquefaction Transportation Labor and Expenses	-	-
153	844.5 Measuring and Regulating Labor and Expenses	-	-
154	844.6 Compressor Station Labor and Expenses	-	-
155	844.7 Communication System Expenses	-	-
156	844.8 System Control and Load Dispatching	-	-
157	845.1 Fuel	-	-
158	845.2 Power	-	-
159	845.3 Rents	-	-
160	845.4 Demurrage Charges	-	-
161	(Less) 845.5 Wharfage Receipts-Credit	-	-
162	845.6 Processing Liquefied or Vaporized Gas by Others	-	-
163	846.1 Gas Losses	-	-
164	846.2 Other Expenses	-	-
165	TOTAL Operation (Enter Total of lines 149 thru 164)	-	-
166	Maintenance		
167	847.1 Maintenance Supervision and Engineering	-	-
168	847.2 Maintenance of Structures and Improvements	-	-
169	847.3 Maintenance of LNG Processing Terminal Equipment	-	-
170	847.4 Maintenance of LNG Transportation Equipment	-	-
171	847.5 Maintenance of Measuring and Regulating Equipment	-	-
172	847.6 Miantenance of Compressor Station Equipment	-	-
173	847.7 Maintenance of Communication Equipment	-	-
174	847.8 Maintenance of Other Equipment	-	-
175	TOTAL Maintenance (Enter Total of lines 167 thru 174)	-	-
176	TOTAL Liquefied Nat Gas Terminaling and Processing Exp (Lines 165 & 175)	-	-
177	TOTAL Natural Gas storage (Enter Total of lines 125, 146, and 176)	288,401	288,713
178	3. TRANSMISSION EXPENSES		
179	Operation		
180	850 Operation Supervision and Engineering	-	-
181	851 System Control and Load Dispatching	-	-
182	852 Communication System Expenses	-	-
183	853 Compressor Station Labor and Expenses	-	-
184	854 Gas for Compressor Station Fuel	-	-
185	855 Other Fuel and Power for Compressor Stations	-	-
186	856 Mains Expenses	-	-
187	857 Measuring and Regulating Station Expenses	-	-
188	858 Transmission and Compression of Gas by Others	-	-
189	859 Other Expenses	-	-
190	860 Rents	-	-
191	TOTAL Operation (Enter Total of lines 180 thru 190)	-	-

Name of Respondent	This Report Is:	Date of Report	Year of Report
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STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

Line No.	Amount *(a)*	Amount for Current Year *(b)*	Amount for Previous Year *(c)*
	3. TRANSMISSION EXPENSES (Continued)		
192	Maintenance		
193	861 Maintenance Supervision and Engineering	-	-
194	862 Maintenance of Structures and Improvements	-	-
195	863 Maintenance of Mains	-	-
196	864 Maintenance of Compressor Station Equipment	-	-
197	865 Maintenance of Measuring and Reg. Station Equipment	-	-
198	866 Maintenance of Communication Equipment	-	-
199	867 Maintenance of Other Equipment	-	-
200	TOTAL Maintenance (Enter Total of lines 193 thru 199)	-	-
201	TOTAL Transmission Expenses (Enter Total of lines 191 and 200)	-	-
202	4. DISTRIBUTION EXPENSES		
203	Operation		
204	870 Operation Supervision and Engineering	764,808	796,537
205	871 Distribution Load Dispatching	-	-
206	872 Compressor Station Labor and Expenses	-	-
207	873 Compressor Station Fuel and Power	-	-
208	874 Mains and Services Expenses	2,294,277	2,022,856
209	875 Measuring and Regulating Station Expenses-General	86,666	86,878
210	876 Measuring and Regulating Station Expenses-Industrial	759	173
211	877 Measuring and Regulating Station Expenses-City Gate Check Station	3,006	3,602
212	878 Meter and House Regulator Expenses	272,999	299,164
213	879 Customer Installations Expenses	1,043,301	958,334
214	880 Other Expenses	690,133	875,804
215	881 Rents	2,469	15,135
216	TOTAL Operation (Enter Total of lines 204 thru 215)	5,158,418	5,058,483
217	Maintenance		
218	885 Maintenance Supervision and Engineering	37,698	42,755
219	886 Maintenance of Structures and Improvements		
220	887 Maintenance of Mains	1,148,752	1,255,654
221	888 Maintenance of Compressor Station Equipment		
222	889 Maintenance of Meas. and Reg. Sta. Equip.-General	254,051	325,930
223	890 Maintenance of Meas. and Reg. Sta. Equip.-Industrial	16,516	23,830
224	891 Maintenance of Meas. and Reg. Sta. Equip.-City Gate Check Station	25,691	38,456
225	892 Maintenance of Services	374,017	443,936
226	893 Maintenance of Meters and House Regulators	947,488	941,376
227	894 Maintenance of Other Equipment	169,319	204,613
228	TOTAL Maintenance (Enter Total of lines 218 thru 227)	2,973,532	3,276,550
229	TOTAL Distribution Expenses (Enter Total of lines 216 and 228)	8,131,950	8,335,033
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	44,989	38,204
233	902 Meter Reading Expenses	118,932	141,600
234	903 Customer Records and Collection Expenses	2,077,632	2,028,727
235	904 Uncollectible Accounts	1,070,768	1,102,858
236	905 Miscellaneous Customer Accounts Expenses	24,480	38,675
237	TOTAL Customer Accounts Expenses (Enter Total of lines 232 thru 236)	3,336,801	3,350,064

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STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Amount *(a)*	Amount for Current Year *(b)*	Amount for Previous Year *(c)*
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
239	Operation		
240	907 Supervision	-	-
241	908 Customer Assistance Expenses	3,510,927	3,434,627
242	909 Informational and Instructional Expenses	240,786	275,104
243	910 Miscellaneous Customer Service and Informational Expenses	84,257	85,144
244	TOTAL Customer Service and Information Expenses (Lines 240 thru 243)	3,835,970	3,794,875
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision		-
248	912 Demonstrating and Selling Expenses	-	260
249	913 Advertising Expenses	-	550
250	916 Miscellaneous Sales Expenses	-	-
251	TOTAL Sales Expenses (Enter Total of lines 247 thru 250)	-	810
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries	4,228,543	3,618,065
255	921 Office Supplies and Expenses	562,431	565,772
256	(Less) (922) Administrative Expenses Transferred-Cr.	-	-
257	923 Outside Services Employed	1,409,392	1,439,821
258	924 Property Insurance	218,506	176,220
259	925 Injuries and Damages	541,570	505,793
260	926 Employee Pensions and Benefits	3,507,349	3,920,908
261	927 Franchise Requirements	-	-
262	928 Regulartory Commission Expenses	1,158,227	1,057,683
263	(Less) (929) Duplicate Charges-Cr.	-	-
264	930.1 General Advertising Expenses	1,654	-
265	930.2 Miscellaneous General Expenses	595,856	761,419
266	931 Rents	51,232	48,005
267	TOTAL Operation (Enter Total of lines 254 thru 266)	12,274,760	12,093,686
268	Maintenance		
269	935 Maintenance of General Plant	1,521,580	1,430,607
270	TOTAL Administrative and General Exp (Total of lines 267 and 269)	13,796,340	13,524,293
271	TOTAL Gas O. and M. Exp (Lines 97,177,201,229,237,244,251,and 270)	113,335,011	98,657,911
		0.00	0.00

NUMBER OF GAS DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.
2. If the respondent's payroll for the reporting period includes any special constrction personnel, include such employees on line 3, and show the number of such special construction employees in a foonote.
3. The number of employees assignable to the gas department from joint function of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the gas department from joint functions.

1. Payroll Period Ended (Date) December 31, 2021		
2. Total Regular Full-Time Employees	62	63
3. Total Part-Time and Temporary Employees allocation of General Employees	1	2
4. Total Employees	63	65

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	[X] An Original [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - ALLOCATED DEPRECIATION, DEPLETION AND AMORTIZATION OF GAS PLANT (ACCT 403, 404.1,404.2, 404.3, 405)

(Except Amortization of Acquisition Adjustments)

Report the amounts of depreciation expense, depletion and amortization for the accounts indicated and classify according to the plant functional groups shown.

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization and Depletion of Producing Natural Gas Land & Land Rights (Account 404.1) (c)	Amortization of Underground Storage Land and Land Rights (Account 404.2) (d)	Amortization of Other Limited-Term Gas Plant (Account 404.3) (e)	Amortization of Leasehold Improvements (Account 404.6) (f)	Amortization of Other Gas Plant (Account 405) (g)	Total (h)
1	Intangible plant				8,067			8,067
2	Production plant, manufactured gas							0
3	Production and gathering plant, natural gas							
4	Products extraction plant							
5	Undergound gas storage plant	122,217						122,217
6	Other storage plant							
7	Base load LNG terminaling and processing plant							
8	Transmission plant							0
9	Distribution plant	9,747,926						9,747,926
10	General plant	205,067						205,067
11	Common plant-gas	2,166,822			3,985,096			6,151,918
12								
13								
14								
15								
16								
17								
18								
19	TOTAL	12,242,032	0	0	3,993,163	0	0	16,235,195

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - ALLOCATED TAXES, OTHER THAN INCOME TAXES (Account 408.1)

Line No.	Kind of Tax *(a)*	Amount *(b)*
1		
2		
3	Real and Personal Property Tax	4,795,231
4		
5	Municipal Occupation & License Tax	4,210,228
6		
7	Payroll Taxes	744,615
8		
9		
10		
11		
12		
13		
14		
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18		
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44		
45		
46		
47		
48	TOTAL (Must agree with page 1, line 11)	9,750,074

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(M, D, Y) May 1, 2022	Dec. 31, 2021

STATE OF OREGON - ALLOCATED CALCULATION OF CURRENT FEDERAL INCOME TAX EXPENSE (Account 409.1)

1. Report amounts used to derive current Federal income tax expense, Account 409.1, for the reporting period. If amounts ar shown in thousands, show (000) in the heading for column (b).
2. Show amounts increasing taxable income as positive values and amounts decreasing taxable income as negative
3. Current tax expense on this schedule must match the amount reported on page 1, line 12 of this report. Separately identif adjustments arising from revisions of prior year accruals.
4. Minor amounts of other additions (subtractions) may be grouped

Line No.	Particulars (Details) *(a)*	Amount *(b)*
1		
2	Operating Revenue	161,312,114
3	Operating & Maintenance Expense	(113,335,011)
4	Book Depreciation & Amortization	(15,982,597)
5	Taxes Other than FIT	(10,595,213)
6	Interest Expense	(8,008,155)
7		
8	Net Operating Income Before FIT	13,391,138
9		
10	Schedule M Adjustments	(21,666,605)
11		
12	Taxable Net Operating Income (loss)	(8,275,467)
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26	Federal Tax Net Income (loss)	(8,275,467)
27	Show computation of Tax:	
	Tax Rate	21%
	Total Federal Income Tax	(1,737,848)
	Deferred FIT	3,616,631
	Total FIT/Deferred FIT	1,878,783

The Federal Income Tax computation is from the Avista Corporation's Results of Operations System. As the "Results" system includes allocations of various indirect revenue and cost elements, the values in th allocation of Federal income taxes will not agree with certain supporting schedules

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(M, D, Y) May 1, 2022	Dec. 31, 2021

STATE OF OREGON -
ALLOCATED CALCULATION OF CURRENT STATE INCOME (EXCISE) TAX EXP. (Account 409.1)

1. Report amounts used to derive current state income (excise) tax expense, Account 409.1, for the reporting period. If amount are shown in thousands, show (000) in the heading for column (b).
2. Show amounts increasing taxable income as positive values and amounts decreasing taxable income as negative
3. Current tax expense on this schedule must match the amount reported on page 1, line 13 of this report. Separately identif adjustments arising from revisions of prior year accruals.
4. Minor amounts of other additions (subtractions) may be grouped

Line No.	Particulars (Details) *(a)*	Amount *(b)*
1	Federal Tax Net Income (loss) from page 12	(8,275,467)
2	Add back: State Income Taxes Accrued	70,000
3		
4	Oregon Taxable Income (Loss)	(8,205,467)
5		
6	Oregon SIT Rate	7.60%
7		
8	Oregon SIT	0
9	Minimum Tax	100,000
10	Greater of Calculated SIT or Minimum Oregon Tax	100,000
11		
12	Oregon Natural Gas Allocation Factor	70.088%
13		
14	Oregon Natural Gas SIT	70,088
15		
16	Oregon Commercial Activity Tax (CAT)	775,051
17		
18	State Income Tax	845,139
19		
20		
21		
22		
23		
24		
25		
26		
27		
28	State Tax Net Income	845,139
29	The Federal Tax Net Income computation is from the Avista Corporation's Results of Operations system The commercial activity tax amount is an estimate based on federal taxable revenues and cost of goods sold	

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	*(M, D, Y)* May 1, 2022	Dec. 31, 2021

STATE OF OREGON - ALLOC. ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. In the space provided:
   (a) Identify, by amount and classification, significant items for which deferred taxes are being provided.

Line No.	Account Subdivisions *(a)*	Balance at Beginning of Year *(b)*	CHANGES DURING YEAR Amounts Debited to Account 410.1 *(c)*	CHANGES DURING YEAR Amounts Credited to Account 411.1 *(d)*
1	Electric			
2				
3				
4				
5				
6				
7	Other			
8	TOTAL ELECTRIC			
9	Gas Purchased Gas Adjustment			
10				
11	All Other			
12				
13				
14				
15	Other			
16	TOTAL GAS	N/A	5,145,263	1,528,632
17	Other (Specify)			
18	TOTAL (ACCOUNT 190)			
19	Classification of Totals			
20	Federal Income Tax	N/A	5,145,263	1,528,632
21	State Income Tax			
22	Local Income Tax			

Allocation to balance sheet accounts by state is not available. Total expense/credit to 410.1 and 411.1 is reflected in Account 190 for reporting purposes.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - ALLOC. ACCUM. DEF. INCOME TAXES (Acct. 190) (Con't.)

(b) Indicate insignificant amounts under OTHER.

3. Beginning balance may be omitted if not readily available. Report gas utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 *(e)*	Amounts Credited to Account 411.2 *(f)*	Debits Acct. No. *(g)*	Debits Amount *(h)*	Credits Acct. No. *(i)*	Credits Amount *(j)*	Balance at End of Year *(k)*	Line No.
							1
							2
							3
							4
							5
							6
							7
							8
						0	9
							10
						0	11
							12
							13
							14
							15
						N/A	16
							17
							18
							19
						N/A	20
							21
							22

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(M, D, Y) May 1, 2022	Dec. 31, 2021

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INCOME TAXES

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amortizable property.
2. In the space provided furnish explanations, including the following in columnar order:
   - (a) State each certification number with a brief description of property.
   - (b) Total and amortizable cost of such property.
   - (c) Date amortization for tax purposes commenced.
   - (d) "Normal" depreciation rate used in computing the deferred tax.

Line No.	Account Subdivisions *(a)*	Balance at Beginning of Year *(b)*	CHANGES DURING YEAR Amounts Debited to Account 410.1 *(c)*	CHANGES DURING YEAR Amounts Credited to Account 411.1 *(d)*
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other			
6				
7				
8	TOTAL Electric (Total of lines 3 thru 7)	0		
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other			
13				
14				
15	Total Gas (Total of lines 10 thru 14)	0		
16	Other (Specify)			
17	Total (Acct 281) (Total of 8, 15 & 16)	0		
18	Classification of TOTAL			
19	Federal Income tax			
20	State Income Tax			
21	Local Income Tax			

Allocation to balance sheet accounts by state is not available. Total expense/credit to 410.1 and 411.1 is reflected in Account 190 for reporting purposes.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(M, D, Y) May 1, 2022	Dec. 31, 2021

STATE OF OREGON - ALLOC. ACCELERATED AMORTIZATION PROPERTY (Acct. 281) Con't.

(e) Tax rate used to originally defer amounts and the tax rate used during the current year to amortize previous deferrals.

3. Beginning balance may be omitted if not readily available. Report gas utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 *(e)*	Amounts Credited to Account 411.2 *(f)*	Acct. No. *(g)*	Amount *(h)*	Acct. No. *(i)*	Amount *(j)*	*(k)*	
							1
							2
							3
							4
							5
							6
							7
						0	8
							9
							10
							11
							12
							13
							14
						0	15
							16
						0	17
							18
							19
							20
							21

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(M, D, Y) May 1, 2022	Dec. 31, 2021

STATE OF OREGON - ALLOC. ACCUM. DEFERRED INCOME TAXES (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred taxes related to property not subject to accelerated amortization.
2. In the space provided furnish explanations, including the following in columnar order:
   (a) State the general method or methods of liberalized depreciation being used (sum-of-year digits, declining balance, etc.)
   (b) Estimated lives (i.e. useful life, guideline life, guideline class life, etc.)
   (c) Classes of plant to which each method is being applied and date method was adopted

Line No.	Account Subdivisions *(a)*	Balance at Beginning of Year *(b)*	CHANGES DURING YEAR Amounts Debited to Account 410.1 *(c)*	CHANGES DURING YEAR Amounts Credited to Account 411.1 *(d)*
1	Account 282			
2	Electric			
3	Gas			
4	Other (Define)			
5	TOTAL (Lines 2 thru 4)			
6	Other (Specify)			
7	Acquisition Adjustment			
8				
9	TOTAL Account 282 (Lines 5 thru 8)	0	0	
10	Classification of TOTAL			
11	Federal Income Tax			
12	State Income Tax			
13	Local Income Tax			

Allocation to balance sheet accounts by state is not available. Total expense/credit to 410.1 and 411.1 is reflected in Account 190 for reporting purposes.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) May 1, 2022	Dec. 31, 2021

STATE OF OREGON - ALLOCATED OTHER PROPERTY (Acct. 282) (Con't.)

3. Beginning balance may be omitted if not readily available. Report gas utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 *(e)*	Amounts Credited to Account 411.2 *(f)*	Acct. No. *(g)*	Amount *(h)*	Acct. No. *(i)*	Amount *(j)*	Balance at End of Year *(k)*	Line No.
							1
							2
						0	3
							4
						0	5
							6
						0	7
							8
0						0	9
							10
						0	11
						0	12
							13

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - ALLOC. ACCUM. DEF. 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. In the space provided below include amounts relating to insignificant items under Other.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Electric			
4				
5				
6				
7				
8	Other			
9	TOTAL Electric (Total Lines 3 thru 8)			
10	Gas			
11	Gas			
12				
13	Deferred Gas Estimate			
14				
15				
16	Other			
17	TOTAL Gas (Total Lines 11 thru 16)	0	0	
18	Other (Specify)			
19	TOTAL Account 283 (Enter Total lines 9, 17 and 18)	0	0	
20	Classification of TOTAL			
21	Federal Income Tax	0	0	
22	State Income Tax			
23	Local Income Tax			

Allocation to balance sheet accounts by state is not available. Total expense/credit to 410.1 and 411.1 is reflected in Account 190 for reporting purposes.

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - ALLOC. ACCUM. DEF. INCOME TAXES - OTHER (Acct. 283) (Con't)

3. Beginning balance may be omitted if not readily available. Report gas utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Acct. No. (g)	Amount (h)	Acct. No. (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
						0	11
							12
						0	13
							14
							15
							16
						0	17
							18
						0	19
							20
						0	21
							22
							23

Name of Respondent Avista Corp.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report ((M, D, Y) May 1, 2022	Year of Report Dec. 31, 2021

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions *(a)*	Balance at Beginning of Year *(b)*	Deferred for Year Account No. *(c)*	Deferred for Year Amount *(d)*	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)
1	NONE								
2									
3									
4									
5									
6									
8									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									
30									
31									

Name of Respondent	This Report Is:	Date of Report ((M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. 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)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)			
1	Gas Utility								
2	3%								
3	4%								
4	7%								
5	10%								
6	TOTAL	0.00						0.00	
7	Other (List separately and show 3%, 4%, 7%, 10%, and TOTAL)								
8									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									
30									
31									

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	[X] An Original [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - SITUS UTILITY PLANT
SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant In Service (Classified)	731,318,986	249,451,304	480,485,192			1,382,490
4	Property Under Capital Leases	0					
5	Plant Purchased or Sold						
6	Completed Construction not Classified						
7	Experimental Plant Unclassified						
8	TOTAL (Enter Total of lines 3 thru 7)	731,318,986	249,451,304	480,485,192			1,382,490
9	Leased to Others						
10	Held for Future Use						
11	Construction Work in Progress	2,021,841		2,021,841			
12	Acquisition Adjustments	0					
13	TOTAL Utility Plant (Lines 8 thru 12)	733,340,827	249,451,304	482,507,033			1,382,490
14	Accum. Prov. for Depr., Amort., Depl.	225,266,975	87,991,588	136,980,680			294,707
15	Net Utility Plant (Line 13 less 14)	508,325,254	161,590,183	345,647,288			1,087,783
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION & DEPLETION						
17	In Service:						
18	Depreciation	225,015,573	87,861,121	136,859,745			294,707
19	Amort. & Depl. of Producing Natural Gas Land & Land Rights						
20	Amort. of Underground Storage Land & Land Rights						
21	Amort. of Other Utility Plant	251,402	130,467	120,935			0
22	TOTAL in Service (lines 18 thru 21)	225,266,975	87,991,588	136,980,680			294,707
23	Leased to Others						
24	Depreciation						
25	Amortization and Depletion						
26	TOTAL Leased to Others (Lines 24 & 25)	0	0	0			
27	Held for Future Use						
28	Depreciation						
29	Amortization						
30	TOTAL Held for Future Use (Lines 28 & 29)	0	0	0			
31	Abandonment of Leases (Natural Gas)						
32	Amort. of Plant Acquisition Adj.	0	0				
33	TOTAL Accumulated Provisions (Should agree with line 14) (Lines 22, 26, 30, 31 & 32)	225,266,975	87,991,588	136,980,680			294,707

NOTE: Electric plant represents the Coyote Springs 2 plant, which was placed in service on July 1, 2003. Electric depreciation expense is charged to the states of Washington and Idaho.

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - SITUS GAS PLANT IN SERVICE

1. Report below the original cost of gas plant in service according to the prescribed accounts.
2. In addition to Account 101, Gas Plant in Service (Classified), this page and the next include Account 102, Gas Plant Purchased or Sold; Account 103, Experimental Gas Plant Unclassified; and Account 106, Completed Construction Not Classified-Gas.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year unclassified retirements. Attach supplemental statement showing the account 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 the end of the year. (Continued on page 25)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
1	1. Intangible Plant								1
2	301 Organization						0	301	2
3	302 Franchises and Consents							302	3
4	303 Miscellaneous Intangible Plant	406,156	0	0	0	19,795	425,951	303	4
5	TOTAL Intangible Plant	406,156	0	0	0	19,795	425,951		5
6	2. Production Plant								6
7	Natural Gas Production and Gathering Plant								7
8	325.1 Producing Lands	0					0	325.1	8
9	325.2 Producing Leaseholds							325.2	9
10	325.3 Gas Rights							325.3	10
11	325.4 Rights-of-Way							325.4	11
12	325.5 Other Land and Land Rights							325.5	12
13	326 Gas Well Structures							326	13
14	327 Field Compressor Station Structures							327	14
15	328 Field Meas. and Reg. Sta. Structures							328	15
16	329 Other Structures							329	16
17	330 Producing Gas Wells-Well Construction							330	17
18	331 Producing Gas Wells-Well Equipment							331	18
19	332 Field Lines							332	19
20	333 Field Compressor Station Equipment							333	20
21	334 Field Meas. and Reg. Sta. Equipment							334	21
22	335 Drilling and Clearing Equipment							335	22
23	336 Purification Equipment							336	23
24	337 Other Equipment							337	24
25	338 Unsuccessful Exploration & Devel. Costs							338	25
26	TOTAL Production and Gathering Plant	0	0	0	0	0	0		26
27	Products Extraction Plant								27
28	340 Land and Land Rights							340	28
29	341 Structures and Improvements							341	29
30	342 Extraction and Refining Equipment							342	30
31	343 Pipe Lines							343	31
32	344 Extracted Products Storage Equipment							344	32

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - SITUS GAS PLANT IN SERVICE

6. Show in column (f) reclassifications or transfers within utility plant acounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102. In showing the clearance of 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.
7. 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 requirements of these pages.
8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entires have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
33	345 Compressor Equipment							345	33
34	346 Gas Meas. and Reg. Equipment							346	34
35	347 Other Equipment							347	35
36	TOTAL Products Extraction Plant	0	0	0	0	0	0		36
37	TOTAL Nat. Gas Production Plant	0	0	0	0	0	0		37
38	Mfd. Gas Prod. Plant (Submit Suppl. Statement)		0	0	0		0		38
39	TOTAL Production Plant	0	0	0	0	0	0		39
40	3. Natural Gas Storage and Processing Plant								40
41	Underground Storage Plant								41
42	350.1 Land						0	350.1	42
43	350.2 Rights-of-Way						0	350.2	43
44	351 Structures and Improvements						0	351	44
45	352 Wells						0	352	45
46	352.1 Storage Leaseholds and Rights						0	352.1	46
47	352.2 Reservoirs						0	352.2	47
48	352.3 Non-recoverable Natural Gas						0	352.3	48
49	353 Lines						0	353	49
50	354 Compressor Station Equipment						0	354	50
51	355 Measuring and Reg. Equipment						0	355	51
52	356 Purification Equipment						0	356	52
53	357 Other Equipment						0	357	53
54	TOTAL Underground Storage Plant	0	0	0	0	0	0		54
55	Other Storage Plant								55
56	360 Land and Land Rights							360	56
57	361 Structures and Improvements							361	57
58	362 Gas Holders							362	58
59	363 Purification Equipment							363	59
60	363.1 Liquefaction Equipment							363.1	60
61	363.2 Vaporizing Equipment							363.2	61
62	363.3 Compressor Equipment							363.3	62
63	363.4 Meas. and Reg. Equipment							363.4	63
64	363.5 Other Equipment							363.5	64
65	TOTAL Other Storage Plant	0	0	0	0	0	0		65

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - SITUS GAS PLANT IN SERVICE

Line No.	Account *(a)*	Balance at Beginning of Year *(b)*	Additions *(c)*	Retirements *(d)*	Adjustments *(e)*	Transfers *(f)*	Balance at End of Year *(g)*		Line No.
66	Base Load Liquefied Natural Gas Terminaling and Processing Plant								66
67	364.1 Land and Land Rights							364.1	67
68	364.2 Structures and Improvements							364.2	68
69	364.3 LNG Processing Terminal Equipment							364.3	69
70	364.4 LNG Transportation Equipment							364.4	70
71	364.5 Measuring and Regulating Equipment							364.5	71
72	364.6 Compressor Station Equipment							364.6	72
73	364.7 Communications Equipment							364.7	73
74	364.8 Other Equipment							364.8	74
75	TOTAL Base Load Liquefied Natural	0	0	0	0	0	0		75
76	Gas, Terminaling and Processing Plant								76
77	TOTAL Nat. Gas Storage and Proc. Plant	0	0	0	0	0	0		77
78	4. Transmission Plant								78
79	365.1 Land and Land Rights							365.1	79
80	365.2 Rights-of-Way							365.2	80
81	366 Structures and Improvements							366	81
82	367 Mains							367	82
83	368 Compressor Station Equipment							368	83
84	369 Measuring and Reg. Sta. Equipment							369	84
85	370 Communication Equipment							370	85
86	371 Other Equipment							371	86
87	TOTAL Transmission Plant	0	0	0	0	0	0		87
88	5. Distribution Plant								88
89	374 Land and Land Rights	823,678	3,971	0		(1)	827,648	374	89
90	375 Structures and Improvements	666,898	13,089	12,824		355	667,518		90
91	376 Mains	259,317,700	9,972,222	83,315		62,146	269,268,753		91
92	377 Compressor Station Equipment	0	0	0		0	0		92
93	378 Meas. and Reg. Sta. Equip. - General	5,770,282	294,148	112		4,205	6,068,523		93
94	379 Meas. and Reg. Sta. Equip. - City Gate	3,033,699	298,504	45,846		4,942	3,291,299		94
95	380 Services	123,899,434	6,398,480	128,560		1,696	130,171,050		95
96	381 Meters	52,307,592	4,485,740	959,341		19	55,834,010		96
97	382 Meter Installations	0	0	0		0	0		97
98	383 House Regulators	0	0	0		0	0		98
99	384 House Reg. Installations	0	0	0		0	0		99
100	385 Industrial Meas. and Reg. Sta. Equipment	2,503,852	(40,195)	0		265	2,463,922		100
101	386 Other Prop. on Customers' Premises	0					0	386	101
102	387 Other Equipment	539	0	0		0	539	387	102
103	TOTAL Distribution Plant	448,323,674	21,425,959	1,229,998	0	73,627	468,593,262		103

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - SITUS GAS PLANT IN SERVICE

Line No.		Account *(a)*	Balance at Beginning of Year *(b)*	Additions *(c)*	Retirements *(d)*	Adjustments *(e)*	Transfers *(f)*	Balance at End of Year *(g)*		Line No.
104		6. General Plant								104
105	389	Land and Land Rights	845,134				383	845,517	389	105
106	390	Structures and Improvements	3,897,544	204,521	1,732		(69)	4,100,264	390	106
107	391	Office Furniture and Equipment	12,109	0	0		0	12,109	391	107
108	392	Transportation Equipment	4,423,237	489,351	214,350		(478)	4,697,760		108
109	393	Stores Equipment	20,792	0	0		0	20,792		109
110	394	Tools, Shop, and Garage Equipment	977,981	69,553	86,643		213	961,104		110
111	395	Laboratory Equipment	18,586	0	0		0	18,586		111
112	396	Power Operated Equipment	43,834	0	0		0	43,834		112
113	397	Communication Equipment	1,043,949	(147)	287,244		363	756,921		113
114	398	Miscellaneous Equipment	2,367	6,725				9,092	398	114
115		Subtotal	11,285,533	770,003	589,969	0	412	11,465,979		115
116	399	Other Tangible Property							399	116
117		TOTAL General Plant	11,285,533	770,003	589,969	0	412	11,465,979		117
118		TOTAL (Accounts 101 and 106)	460,015,363	22,195,962	1,819,967	0	93,834	480,485,192		118
119		Gas Plant Purchased (See Instr. 8)								119
120		(Less) Gas Plant Sold (See Instr. 8)								120
121		Experimental Gas Plant Unclassified								121
122		TOTAL Gas Plant in Service	460,015,363	22,195,962	1,819,967	0	93,834	480,485,192		122

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - SITUS GAS PLANT IN SERVICE

SUPPLEMENT TO PAGE 25

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
	304 Land and Land Rights	59,923				0	59,923	304	
	305 Structures and Improvements						0	305	
	311 Liquified Petroleum Gas Equipment	0					0	311	
38	Total Mfd. Gas Prod. Plant	59,923	0	0	0	0	59,923		38

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - SITUS GAS PLANT HELD FOR FUTURE USE

1. Report separately each property held for future use at end of the year having an original cost of $100,000 or more. Other items of property held for future use may be grouped provided that the number of properties so grouped is indicated.
2. For property having an original cost of $100,000 or more previously used in utility operations, now held for future use, give, 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)	Dated Expected To Be Used In Utility Service (c)	Balance at End of Year (d)
1				
2	NONE			
3				
4				
5				
6				
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11				
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44	TOTALS			

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - SITUS CONSTRUCTION WORK IN PROGRESS - (Account 107)

1. Report below descriptions and balances at end of year of project in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Gas (Account 107) (b)	Estimated Additional Cost of Project (c)
1	Minor Projects Under $1,000,000:	2,021,841	3,047,005
2			
3			
4			
5			
9			
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16			
17			
18	(1) Minor Projects Under $1,000,000 represents mains and		
19	service replacements, regulator reliability programs, gas		
20	telemetry, etc.		
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38	TOTALS	2,021,841	3,047,005

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - SITUS ACC. PROV. FOR DEPR. OF GAS UTILITY PLANT (Acct. 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, line 11, column (c), and that reported for gas plant in service, pages 24-27, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 of the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Gas Plant in Service (c)	Gas Plant Held for Future Use (d)	Gas Plant Leased to Others (e)
1	Balance Beginning of Year	130,342,224	130,342,224	0	0
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	9,953,376	9,953,376		
4	(413) Exp. of Gas Plt. Leas. to Others				
5	Transportation Expenses-Clearing	304,698	304,698		
6	Other Clearing Accounts				
7	Other Accounts (Specify):	0			
8					
9	TOTAL Deprec. Prov. for Year (Enter Total of lines 3 thru 8)	10,258,074	10,258,074	0	0
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	1,819,967	1,819,967		
12	Cost of Removal	(64,991)	(64,991)		
13	Salvage (Credit)	0			
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)	1,754,976	1,754,976	0	0
15	Other Debit or Credit Items (Describe)	(1,864,643)	(1,864,643)		
16	Transfer of Intang Plt & Exclude Comm. Plt.				
17	Balance End of Year (Enter Total of lines 1, 9, 14, 15, and 16)	136,980,680	136,980,680	0	0
	Section B. Balances at End of Year According to Functional Classifications				
18	Production-Manufactured Gas				
19	Prod. and Gathering-Natural Gas				
20	Products Extraction-Natural Gas				
21	Underground Gas Storage	0			
22	Other Storage Plant				
23	Base Load LNG Term and Proc. Plt.				
24	Transmission				
25	Distribution	131,632,275	131,632,275		
26	General	5,348,405	5,348,405		
27	TOTAL (Enter Total of lines 18 thru 26)	136,980,680	136,980,680	0	0

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - ALLOCATED
SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant In Service (Classified)	66,608,064		9,519,951			57,088,113
4	Property Under Capital Leases	945,434					945,434
5	Plant Purchased or Sold						
6	Completed Construction not Classified						
7	Experimental Plant Unclassified						
8	TOTAL (Enter Total of lines 3 thru 7)	67,553,498		9,519,951			58,033,547
9	Leased to Others						
10	Held for Future Use						
11	Construction Work in Progress	1,377,704		1,770			1,375,934
12	Acquisition Adjustments						
13	TOTAL Utility Plant (Lines 8 thru 12)	68,931,202		9,521,721			59,409,481
14	Accum. Prov. for Depr., Amort., Depl.	24,314,257		2,284,645			22,029,612
15	Net Utility Plant (Line 13 less 14)	44,616,945		7,237,076			37,379,869
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION & DEPLETION						
17	In Service:						
18	Depreciation	10,980,669		2,230,044			8,750,625
19	Amort. & Depl. of Producing Natural Gas Land & Land Rights						
20	Amort. of Underground Storage Land & Land Rights						
21	Amort. of Other Utility Plant	13,333,588		54,601			13,278,987
22	TOTAL in Service (lines 18 thru 21)	24,314,257		2,284,645			22,029,612
23	Leased to Others						
24	Depreciation						
25	Amortization and Depletion						
26	TOTAL Leased to Others (Lines 24 & 25)	0		0			
27	Held for Future Use						
28	Depreciation						
29	Amortization						
30	TOTAL Held for Future Use (Lines 28 & 29)	0		0			
31	Abandonment of Leases (Natural Gas)						
32	Amort. of Plant Acquisition Adj.						
33	TOTAL Accumulated Provisions (Should agree with line 14) (Lines 22, 26, 30, 31 & 32)	24,314,257		2,284,645			22,029,612

NOTE: Property Under Capital Leases is comprised of ROU Assests

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE

1. Report below the original cost of gas plant in service according to the prescribed accounts.
2. In addition to Account 101, Gas Plant in Service (Classified), this page and the next include Account 102, Gas Plant Purchased or Sold; Account 103, Experimental Gas Plant Unclassified; and Account 106, Completed Construction Not Classified-Gas.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year
4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c) Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year unclassified retirements. Attach supplemental statement showing the account 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 the end of the year. (Continued on page 33)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
1	1. Intangible Plant								1
2	301 Organization						0	301	2
3	302 Franchises and Consents						0	302	3
4	303 Miscellaneous Intangible Plant	119,194	3,734	0		15,617	138,545	303	4
5	TOTAL Intangible Plant	119,194	3,734	0	0	15,617	138,545		5
6	2. Production Plant								6
7	Natural Gas Production and Gathering Plant								7
8	325.1 Producing Lands						0	325.1	8
9	325.2 Producing Leaseholds						0	325.2	9
10	325.3 Gas Rights						0	325.3	10
11	325.4 Rights-of-Way						0	325.4	11
12	325.5 Other Land and Land Rights						0	325.5	12
13	326 Gas Well Structures						0	326	13
14	327 Field Compressor Station Structures						0	327	14
15	328 Field Meas. and Reg. Sta. Structures						0	328	15
16	329 Other Structures						0	329	16
17	330 Producing Gas Wells-Well Construction						0	330	17
18	331 Producing Gas Wells-Well Equipment						0	331	18
19	332 Field Lines						0	332	19
20	333 Field Compressor Station Equipment						0	333	20
21	334 Field Meas. and Reg. Sta. Equipment						0	334	21
22	335 Drilling and Clearing Equipment						0	335	22
23	336 Purification Equipment						0	336	23
24	337 Other Equipment						0	337	24
25	338 Unsuccessful Exploration & Devel. Costs						0	338	25
26	TOTAL Production and Gathering Plant	0	0	0	0	0	0		26
27	Products Extraction Plant								27
28	340 Land and Land Rights						0	340	28
29	341 Structures and Improvements						0	341	29
30	342 Extraction and Refining Equipment						0	342	30
31	343 Pipe Lines						0	343	31
32	344 Extracted Products Storage Equipment						0	344	32

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(M, D, Y) May 1, 2022	Dec. 31, 2021

STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE

6. Show in column (f) reclassifications or transfers within utility plant acounts. Include also in column (f) the additions or reductions of primary account classifications arising fror distribution of amounts initially recorded in Account 102. In showing the clearance o Account 102, include in column (e) the amounts with respect to accumulated provision fo 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

7. 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 requirements of these page:
8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold name of vendor or purchaser, and date of transaction. If proposed journal entires have been filed with the Commissioı as required by the Uniform System of Accounts, give also date of such filing

Line No.	Account (a)	Balance at Beginning of Yeaı (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
33	345 Compressor Equipment						0	345	33
34	346 Gas Meas. and Reg. Equipment						0	346	34
35	347 Other Equipment						0	347	35
36	TOTAL Products Extraction Plant	0	0	0	0	0	0		36
37	TOTAL Nat. Gas Production Plant	0	0	0	0				37
38	Mfd. Gas Prod. Plant (Submit Suppl. Statement)	59,923				0	59,923		38
39	TOTAL Production Plant	59,923	0	0	0	-	59,923		39
40	3. Natural Gas Storage and Processing Plant								40
41	Underground Storage Plant								41
42	350.1 Land	87,585					87,585	350.1	42
43	350.2 Rights-of-Way	669					669	350.2	43
44	351 Structures and Improvements	88,099				45,348	133,447	351	44
45	352 Wells	3,299,404				45,335	3,344,739	352	45
46	352.1 Storage Leaseholds and Rights	0				0	0	352.1	46
47	352.2 Reservoirs	0				0	0	352.2	47
48	352.3 Non-recoverable Natural Gas	0				0	0	352.3	48
49	353 Lines	170,745				0	170,745	353	49
50	354 Compressor Station Equipment	3,190,323				45,336	3,235,659	354	50
51	355 Measuring and Reg. Equipment	106,036				45,337	151,373	355	51
52	356 Purification Equipment	15,106				0	15,106	356	52
53	357 Other Equipment	83,624				45,336	128,960	357	53
54	TOTAL Underground Storage Plant	7,041,591	0	0	0	226,692	7,268,283		54
55	Other Storage Plant								55
56	360 Land and Land Rights						0	360	56
57	361 Structures and Improvements						0	361	57
58	362 Gas Holders						0	362	58
59	363 Purification Equipment						0	363	59
60	363.1 Liquefaction Equipment						0	363.1	60
61	363.2 Vaporizing Equipment						0	363.2	61
62	363.3 Compressor Equipment						0	363.3	62
63	363.4 Meas. and Reg. Equipment						0	363.4	63
64	363.5 Other Equipment						0	363.5	64
65	TOTAL Other Storage Plant	0	0	0	0	0	0		65

Name of Respondent	This Report Is:	Date of Report (*M, D, Y*)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE

Line No.	Account *(a)*	Balance at Beginning of Year *(b)*	Additions *(c)*	Retirements *(d)*	Adjustments *(e)*	Transfers *(f)*	Balance at End of Year *(g)*		Line No.
66	Base Load Liquefied Natural Gas Terminaling and Processing Plant								66
67	364.1 Land and Land Rights						0	364.1	67
68	364.2 Structures and Improvements						0	364.2	68
69	364.3 LNG Processing Terminal Equipment						0	364.3	69
70	364.4 LNG Transportation Equipment						0	364.4	70
71	364.5 Measuring and Regulating Equipment						0	364.5	71
72	364.6 Compressor Station Equipment						0	364.6	72
73	364.7 Communications Equipment						0	364.7	73
74	364.8 Other Equipment						0	364.8	74
75	TOTAL Base Load Liquefied Natural	0	0	0	0	0	0		75
76	Gas, Terminaling and Processing Plant						0		76
77	TOTAL Nat. Gas Storage and Proc. Plant	7,041,591	0	0	0	226,692	7,268,283		77
78	4. Transmission Plant								78
79	365.1 Land and Land Rights						0	365.1	79
80	365.2 Rights-of-Way						0	365.2	80
81	366 Structures and Improvements						0	366	81
82	367 Mains						0	367	82
83	368 Compressor Station Equipment						0	368	83
84	369 Measuring and Reg. Sta. Equipment						0	369	84
85	370 Communication Equipment						0	370	85
86	371 Other Equipment						0	371	86
87	TOTAL Transmission Plant	0	0	0	0	0	0		87
88	5. Distribution Plant								88
89	374 Land and Land Rights						0	374	89
90	375 Structures and Improvements						0	375	90
91	376 Mains						0	376	91
92	377 Compressor Station Equipment						0	377	92
93	378 Meas. and Reg. Sta. Equip. - General						0	378	93
94	379 Meas. and Reg. Sta. Equip. - City Gate						0	379	94
95	380 Services						0	380	95
96	381 Meters						0	381	96
97	382 Meter Installations						0	382	97
98	383 House Regulators						0	383	98
99	384 House Reg. Installations						0	384	99
100	385 Industrial Meas. and Reg. Sta. Equipment		0			0	0	385	100
101	386 Other Prop. on Customers' Premises	0					0	386	101
102	387 Other Equipment	0					0	387	102
103	TOTAL Distribution Plant	0	0	0	0	0	0		103

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE

Line No.		Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
104		6. General Plant								104
105	389	Land and Land Rights	0					0	389	105
106	390	Structures and Improvements						0	390	106
107	391	Office Furniture and Equipment	98,634	0			1,581	100,215	391	107
108	392	Transportation Equipment	30,097	48,573	32,735		(15,645)	30,290	392	108
109	393	Stores Equipment	0	0	0		0	0	393	109
110	394	Tools, Shop, and Garage Equipment	1,639,204	34,965	107		92,672	1,766,734	394	110
111	395	Laboratory Equipment	63,537	2,546	0		6,387	72,470	395	111
112	396	Power Operated Equipment	0	0	0		0	0	396	112
113	397	Communication Equipment	158,872	0	22,938		(52,443)	83,491	397	113
114	398	Miscellaneous Equipment	0					0	398	114
115		Subtotal	1,990,344	86,084	55,780	0	32,552	2,053,200		115
116	399	Other Tangible Property	0					0	399	116
117		TOTAL General Plant	1,990,344	86,084	55,780	0	32,552	2,053,200		117
118		TOTAL (Accounts 101 and 106)	9,211,052	89,818	55,780	0	274,861	9,519,951		118
119		Gas Plant Purchased (See Instr. 8)								119
120		(Less) Gas Plant Sold (See Instr. 8)								120
121		Experimental Gas Plant Unclassified								121
122		TOTAL Gas Plant in Service	9,211,052	89,818	55,780	0	274,861	9,519,951		122

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - ALLOCATED GAS 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 $100,000 or more. Other items of property held for future use may be grouped provided that the number of properties so grouped is indicatec
2. For property having an original cost of $100,000 or more previously used in utility operations, now held for future use, give, ir addition to other required information, the date that utility use of such property was discontinued, and the date the origina 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				
2	NONE			
3				
4				
5				
6				
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44	TOTALS			

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - ALLOCATED CONSTRUCTION WORK IN PROGRESS - (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 Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Gas (Account 107) (b)	Estimated Additional Cost of Project (c)
1	Minor Projects Under $1,000,000:	1,617,184	3,338,155
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15	(1) Minor Projects Under $1,000,000 represents mains and		
16	service replacements, regulator reliability programs, gas		
17	telemetry, facilities and ET projects, etc.		
18			
19			
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38	Totals	1,617,184	3,338,155

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - ALLOC. ACC. PROV. FOR DEPR. OF GAS UTILITY PLANT (Acct. 119)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, line 11, column (c), and that reported for gas plant in service, pages 32-35, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 119 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)	Gas Plant in Service (c)	Gas Plant Held for Future Use (d)	Gas Plant Leased to Others (e)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	2,063,779	2,063,779	0	0
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	238,111	238,111		
4	(413) Exp. of Gas Plt. Leas. to Others				
5	Transportation Expenses-Clearing	0			
6	Other Clearing Accounts				
7	Other Accounts (Specify):	0	0		
8					
9	TOTAL Deprec. Prov. for Year (Enter Total of lines 3 thru 8)	238,111	238,111	0	0
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	0	0		
12	Cost of Removal	0	0		
13	Salvage (Credit)	0	0		
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)	0	0	0	0
15	Other Debit or Credit Items (Describe):	(71,846)	(71,846)		
16					
17	Balance End of Year (Enter Total of lines 1, 9, 14, 15, and 16)	2,230,044	2,230,044	0	0
	Section B. Balances at End of Year According to Functional Classifications				
18	Production-Manufactured Gas				
19	Prod. and Gathering-Natural Gas				
20	Products Extraction-Natural Gas				
21	Underground Gas Storage	1,517,319	1,517,319		
22	Other Storage Plant				
23	Base Load LNG Term and Proc. Plt.				
24	Transmission				
25	Distribution	0			
26	General	712,725	712,725		
27	TOTAL (Enter Total of lines 18 thru 26)	2,230,044	2,230,044	0	0

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(M,D,Y) May 1, 2022	Dec. 31, 2021

STATE OF OREGON - GAS STORED (117, 164.1, 164.2, AND 164.3)

1. Report below the information called for concerning inventories of gas stored
2. The Uniform System of Accounts provides that inventory cost records be maintained on a consolidated basis for all storage projects with separate records showing the Mcf of inputs and withdrawals and balance for each project, except under specified circumstances. If the respondent's inventory cost records are not maintained on a consolidated basis for all storage projects, furnish an explanation of the accounting followed and reason for any deviation from the general basis provided by the Uniform System of Accounts. Separate schedule on this schedule form should be furnished for each group of storage projects for which separate inventory cost records are maintained.
3. If during the year adjustment was made of the stored gas inventory, such as to correct for cumulative inaccuracies of gas measurements, furnish an explanation of the reason for the adjustment, the Mcf and dollar amount of adjustment and account charged or credited.
4. Give a concise statement of the facts and the accounting performed with respect to any encroachment of withdrawals during the year, or restoration of previous encroachment, upon native gas constituting the "gas cushion" of any storage reservoir.
5. If the respondent uses a "base stock" in connection with its inventory accounting, give a concise statement of the basis of establishing such "base stock" and the inventory basis and the accounting performed with respect to any encroachment of withdrawals on "base stock", or restoration of previous encroachment, including brief particulars of any such accounting during the year
6. If respondent has provided accumulated provision for stored gas which may not eventually be fully recovered from any storage project furnish a statement showing: (a) date of Commission authorization of such accumulated provision (b) explanation of circumstances requiring such provision (c) basis of provision and factors of calculation (d) estimated ultimate accumulated provision accumulation (e) a summary showing balance of accumulated provision and entries during year
7. Pressure base of gas volume reported in this schedule is 14.73 psia at 60° F

Line No.	Description	Noncurrent (Account 117) (a)	Current (Account 164.1) (b)	LNG (Account 164.2) (e)	LNG (Account 164.3) (d)	Total (e)
1	Balance, beginning of year	1,261,012	1,044,472	0	0	2,305,484
2	Gas delivered to storage		2,597,585			2,597,585
3	(contra account)					
4	Gas withdrawn from storage		1,726,649			1,726,649
5	(contra account)					
6	Other debits and credits net		0			0
7						
8						
9						
10						
11						
12	Balance, end of year	1,261,012	1,915,408	0	0	3,176,420
13	Therm	2,259,880	6,672,830			8,932,710
14	Amount per Mcf	$5.58	$2.87			$3.56
15	State basis of segregation of inventory between current and noncurrent portions.					
16	Current portion is gas expected to be sold within a 24-month period. All other gas is considered non-current.					
17	Gas delivered to storage:			Current	LNG	
18	Therm			8,457,100		
19	Amount per therm			$0.31		
20	Cost basis of gas delivered to storage:					
21	Specify: Own production (give production area, see				Average Cost	
22	uniform system of accounts); average system purchases;					
23	specific purchases (state which purchases).					
24	Does cost of gas delivered to storage include any expenses					
25	for use of respondent's transmission, storage or other					
26	facilities? If so, give particulars and date of Commision			No		
27	approval of accounting.					
28						
29	Gas withdrawn from storage:					
30	Therm			8,360,580		
31	Amount per therm			$0.21		
32	Cost basis of withdrawal					
33	Specify: average cost, lifo, fifo, (Explain any change in				Average Cost	
34	inventory basis during year and give date of Commission					
35	approval of the change or approval of an inventory basis					
36	different from that referred to in uniform system of accounts)					
37						
38						
39						
40						

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(M, D, Y) May 1, 2022	Dec. 31, 2021
Conversion Factor to MCF .9756	0.976		

STATE OF OREGON - GAS PURCHASES (Accounts 800, 801,803, 804, 804.1 and 805)

Line No.	Name of Seller (Designate Associated Companies) (a)	Name of Producing Field or Gasoline Plant (b)	Net Rate Effective December 31 (c)
1	Refer to Note (1)		
2	Note (1) The following are the major gas suppliers for the State of Oregon		
3	Bank of Nova Scotia		
4	BP Canada Energy Marketing, Corp.		
5	BP Energy Company		
6	Castleton Commodities Merchant Trading L.P.		
7	CIMA Energy, Ltd		
8	Citadel Energy Marketing LLC		
9	Concord Energy, LLC		
10	ConocoPhillips Canada Marketing & Trading ULC		
11	ConocoPhillips Company		
12	EDF Trading North America, LLC		
13	FortisBC Energy Inc.		
14	Freepoint Commodities LLC		
15	ICE NGX Canada Inc.		
16	IGI Resources Inc.		
17	J. Aron & Company LLC		
18	Koch Energy Services, LLC		
19	Macquarie Energy Canada Ltd		
20	Macquarie Energy LLC		
21	Mercuria Commodities Canada Corporation		
22	Mercuria Energy America, LLC		
23	MIECO LLC		
24	Mieco, Inc.		
25	National Bank of Canada		
26	Occidental Energy Marketing, Inc.		
27	Ovintiv Marketing Inc.		
28	Portland General Electric Company		
29	Powerex		
30	Puget Sound Energy, Inc.		
31	Sacramento Municipal Utility District		
32	Shell Energy North America (Canada) Inc.		
33	Shell Energy North America (US) L.P.		
34	Sierra Pacific Power Company		
35	Summit Energy LLC		
36	Tenaska Marketing Ventures		
37	United Energy Trading LLC		
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Name of Respondent Avista Corp.	This Report is (1) [X] An Original (2) [ ] A Resubmission	Date of Report (M, D, Y) May 1, 2022	Year of Report Dec. 31, 2021

STATE OF OREGON - GAS PURCHASES (Accounts 800, 801, 802, 803, 804, 804.1 and 805) (Con't)

Seller Code (d)	State Code (e)	Count Code (f)	Schedule No. (g)	Schedule Suffix (h)	Date of Contract (i)	Approx BTU Per CU FT (j)	Gas Purchased - Mcf (14.73 PSIA 60°) (k)	Cost of Gas (l)	Cost Per Mcf (Dollars) (m)	Line No.
Refer to Note (1)					Various		31,467,585	$ 68,759,760.71	$2.19	1
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Name of Respondent Avista Corp.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (M, D, Y) May 1, 2022	Year of Report Dec. 31, 2021

STATE OF OREGON - GAS USED IN UTILITY OPERATIONS - CREDIT (Accounts 810, 811, 812)

1. Report below particulars of credits during the year to Accounts 810, 811 and 812, which offset charges to operating expenses or other accounts or the cost of gas from the respondent's own supply.
2. Natural gas means either natural gas unmixed, or any mixture of natural and manufactured gas.
3. If the reported MCF for any use is an estimated quantity, state such fact.
4. If any natural gas was used by the respondent for which charge was not made to the appropriate operating expense or other account, list separately in column (c) the MCF of gas so used, omitting entries in columns (d) and (e).
5. Pressure base of measurement, to be reported in columns (c) and (f) is 14.73 psia at 60° F.

			Natural Gas			Manufactured Gas	
Line No.	Purpose for Which Gas was Used (a)	Account Charged (b)	MCF of Gas Used (14.73 PSIA at 60°F) (c)	Amount of Credit (d)	Amount Per MCF (Cents) (e)	MCF of Gas Used (14.73 PSIA at 60°) (f)	Amount of Credit (g)
1	810 Gas used for Compressor Station Fuel- Credit						
2	811 Gas used for Products Extraction - Credit		12,075,769	$94,949	$0.01		
3	(a) Gas shrinkage & other usage in respondent's own processing						
4	(b) Gas shrinkage, etc. for respondent's gas processed by others						
5	812 Gas used for Other Utility Operations - Credit						
6	(Report separately for each principal use. Group minor uses.)						
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Name of Respondent	This Report Is:	Date of Report	Year of Report
	(1) [X] An Original	(M, D, Y)	
Avista Corp.	(2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021
Year: 201212			

STATE OF OREGON - GAS ACCOUNT - NATURAL GAS

1. The purpose of this schedule is to account for the quantity of natural gas received and delivered by the respondent taking into consideration differences in pressure bases used in measuring MCF of natural gas received and delivered.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3. Enter in column (c) the MCF as reported in the schedules indicated for the respective items of receipts and deliveries.

Line No.	Item *(a)*	Ref. Page No. *(b)*	Therms *(c)*
1	GAS RECEIVED		
2	Natural Gas Produced		
3	LPG Gas Produced and Mixed with Natural Gas		
4	Manufactured Gas Produced and Mixed with Natural Gas		
5	Purchased Gas		
6	Wellhead		
7	Field Lines		
8	Gasoline Plants		
9	Transmission Line		
10	City Gate Under FERC Rate Schedules		322,545,970
11	LNG		
12	Other (imbalances)		425,370
13	TOTAL GAS PURCHASED		322,971,340
14	Gas of Others Received for Transportation		35,698,157
15	Receipts of Respondents' Gas Transported or Compressed by Others		
16	Exchange Gas Received		
17	Gas Withdrawn from Underground Storage		10,109,340
18	Gas Received from LNG Storage		
19	Gas Received from LNG Processing		
20	Other Receipts (Specify): Storage Injections		
	TOTAL RECEIPTS		368,778,837

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(M, D, Y) May 1, 2022	Dec. 31, 2021

STATE OF OREGON - GAS ACCOUNT - NATURAL GAS (Con't)

4. In a footnote report the volumes of gas from respondent's own production delivered to respondent's transmission system and included in natural gas sale.
5. If the respondent operates two or more systems which are not interconnected, separate schedules should be submitted. Insert pages should be used for this purpose.

Line No.	Item (a)	Ref. Page No. (b)	Amount of Therms (c)
	GAS DELIVERED		
22	Natural Gas Sales		
23	a. Field Sales		
24	(i) To Interstate Pipeline Companies for Resale		
25	Pursuant to FERC Rate Schedules		
26	(ii) Retail Industrial Sales		
27	(iii) Other Field Sales		
28	TOTAL FIELD SALES		0
29	b. Transmission Systems Sales		
30	(i) To Interstate Pipeline Co. for Resale Under FERC Rate Schedules		
31	(ii) To Intrastate Pipeline Co. and Gas Utilities for resale under		
32	FERC rate schedules		
33	(iii) Mainline Industrial Sales Under FERC Certification		
34	(iv) Other Mainline Industrial Sales		
35	(v) Other Transmission System Sales		
36	TOTAL TRANSMISSION SYSTEM SALES		0
37	c. Local Distribution by Respondent		
38	(i) Retail Industrial Sales		10,239,201
39	(ii) Other Distribution System Sales		84,961,307
40	TOTAL DISTRIBUTION SYSTEM SALES		95,200,508
41	d. Interdepartmental sales		13,683
42	TOTAL SALES		95,214,191
43			
44	Deliveries of Gas Transported or Compressed for:		
45	a. Other Interstate Pipeline Companies		
46	b. Others		35,698,157
47	TOTAL GAS TRANSPORTED OR COMPRESSED FOR OTHERS		35,698,157
48	Deliveries of Respondent's Gas for Trans. or Compression by Others		
49	Exchange Gas Delivered		
50	Natural Gas Used by Respondent		
51	Natural Gas Delivered to Underground Storage		8,950,400
52	Natural Gas Delivered to LNG Storage		
53	Natural Gas Delivered to LNG Processing		
54	Natural Gas for Franchise Requirements		
55	Other Deliveries (Specify): Sales for Resale		221,089,330
56	TOTAL SALES & OTHER DELIVERIES UNACCOUNTED FOR		360,952,078
57	Production System Losses		
58	Storage Losses		
59	Transmission System Losses		7,826,759
60	Distribution System Losses		
61	Other Losses (Specify in so far as possible):		
62	TOTAL UNACCOUNTED FOR		
63	TOTAL SALES, OTHER DELIVERIES, AND UNACCOUNTED FOR		368,778,837

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(M, D, Y) May 1, 2022	Dec. 31, 2021

STATE OF OREGON - MISCELLANEOUS GENERAL EXPENSES (Account 930.2)

Report below the information called for concerning items included in miscellaneous general expenses.

Line No.	Items *(a)*	Total *(b)*	Amount Applicable to Oregon *(c)*	Amount Applicable to Other States *(d)*
1	Industry Association Dues	166,993	51,321	115,672
2	Experimental and General Research Expenses			
3	Publishing and Distributing Information and Reports to Stockholders; Trustee, Registrar and Transfer Agent Fees and Expenses, and Other Expenses of Servicing Outstanding Securities of the Respondent	293,359	91,004	202,355
4	Other Expenses (List items of $5,000 or more in this column showing the (1) purpose, (2) recipient and (3) amount of such items, Group amounts of less than $5,000 by classes if			
5	Community Relations	170,865	47,068	123,797
6	Board of Director Activites	641,747	199,078	442,669
7	Educational - Informational	121,534	37,701	83,833
8	Emergency Operating Procedure Events	315,619	97,909	217,710
9	Misc. Employee Expenses	5,860	1,833	4,027
10	Misc. Legal, Professional, and General Services	62,467	19,378	43,089
11	Misc. Transportation	92,559	48,389	44,170
12	Other Misc. Expenses <$5k	7,647	2,175	5,472
13				
14				
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24				
	TOTAL	1,878,650	595,856	1,282,794

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - POLITICAL ADVERTISING

1. List all payments for advertising, the purpose of which is to aid or defeat any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation.
2. Give the specific purpose of such advertising, when and where placed, and the account or accounts charged.
3. Report whole dollars only. Provide a total for each account and a grand total.

Line No.	Description *(a)*	Account Charged *(b)*	Amount *(c)*
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3	NONE		
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Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - POLITICAL CONTRIBUTIONS

1. List all payments or contributions to persons and organizations for the purpose of aiding or defeating any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation.
2. The purpose of all contributions or payments should be clearly explained.
3. Report whole dollars only. Provide a total for each account and a grand total.

Line No.	Description *(a)*	Account Charged *(b)*	Amount *(c)*
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42	TOTAL		-

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - EXPENDITURES TO ANY PERSON OR ORGANIZATION HAVING AN AFFILIATED INTEREST FOR SERVICES, ETC.

1. Report all expenditures to any person or organization having an affiliated interest for service, advice, auditing associating, sponsoring, engineering, managing, operating, financial, legal or other services. See Oregon Revised Statute 757.015 for definition of "affiliated interest."
2. Give reference if such expenditures have in the past been approved by the Commission. Describe the services received and the account or accounts charged. Report whole dollars only.

Line No.	Description (a)	Account Number (b)	Total Amount (c)	Amount Assigned to Oregon (d)
1				
2	Please refer to the Annual Affiliated Interest Report			
3	pursuant to OAR 860-27-100.			
4				
5	This report will be filed with the Public Utility			
6	Commission of Oregon in June 2022.			
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(M, D, Y) May 1, 2022	Dec. 31, 2021

STATE OF OREGON - DONATIONS AND MEMBERSHIPS

1. List all donations and membership expenditures made by the utility during the year and the amounts charged (items less than $1,000 may be consolidated by category stating the number of organizations included). Give the name, city and state of each organization to whom a donation has been made. Group donations under headings as:
   a. Contributions to and memberships in charitable organizations
   b. Organizations of the utility industry
   c. Technical and professional organizations
   d. Commercial and trade organizations
   e. All other organizations and kinds of donations and contributions
2. List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group of donations.

Line No.	Description (a)	Account Number (b)	Total Amount (c)	Amount Assigned To Oregon (d)
1	a. Contributions to and memberships in charitable organizations			
2	a Less than $1,000		14,409	14,409
3	a Greater than $1,000		50,525	50,525
4	a GOSPEL MISSION		1,000	1,000
	COMPASS HOUSE INC		1,000	1,000
	RECLAIMING LIVES		1,000	1,000
	SOREDI		3,000	3,000
	MAGDALENE HOME		1,000	1,000
	GOLDEN RULE REENTRY		1,000	1,000
	MERCY FOUNDATION		1,000	1,000
	UNION FAIR JR AUCTION		1,500	1,500
	MORROW COUNTY SCHOOL DISTRICT		1,000	1,000
	CASA OF JACKSON COUNTY INC		1,000	1,000
	CHAMBER OF COMMERCE		1,000	1,000
	CITY OF WINSTON		1,000	1,000
	ASHLAND CHAMBER OF COMMERCE		3,500	3,500
	CITY OF GRANTS PASS		1,000	1,000
	SOUTHERN OREGON UNIVERSITY		1,000	1,000
	BOARDMAN CHAMBER OF COMMERCE		1,450	1,450
	RIVERBEND LIVE		1,000	1,000
	SOUTHERN OREGON LAND CONSERVANCY		1,000	1,000
	BENEFIT FOR THE BASIN		1,000	1,000
	BUILDERS ASSOCIATION SOUTHERN OREGON		3,000	3,000
	THE CHAMBER OF MEDFORD / JACKSON COUNTY		6,575	6,575
	CRATERIAN PERFORMANCES		4,000	4,000
	PEAR BLOSSOM RUN		1,000	1,000
	UCAN FOOD BANK		1,500	1,500
	FRIENDS OF THE CHILDREN		1,000	1,000
	SUTHERLIN ROTARY CLUB		1,000	1,000
	TIGER BOOSTERS		1,000	1,000
	SOUTHERN OREGON UNIVERSITY FOUNDATION		1,500	1,500
	GRAY GROUP		1,000	1,000
	ROGUE COMMUNITY HEALTH		1,000	1,000
	SOREDI		2,500	2,500
	OREGON TECH FOUNDATION		1,000	1,000
5	a Total Contributions to and memberships in charitable orgs	426.1	64,934	64,934
6	d. Commercial and trade organizations			
7	d Less than $1,000		5,445	5,445
8	d Greater than $1,000		17,069	17,069
9	d BUILDERS ASSOCIATION OF SOUTHERN OREGON		1,745	1,745
	KLAMATH COUNTY CHAMBER OF COMMERCE		1,598	1,598
	KCEDA		5,000	5,000
	SOREDI		2,500	2,500
	UMPQUA ECONOMIC DEVELOPMENT PARTNERSHIP		5,000	5,000
	THE CHAMBER OF MEDFORD / JACKSON COUNTY		1,226	1,226
10	d Total Commercial and Trade Organizations	426.1	22,514	22,514
11				
12				
13	Subtotal	426.1	87,448	87,448
14				
15				
16	Total		87,448	87,448

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	*(M, D, Y)* May 1, 2022	Dec. 31, 2021

STATE OF OREGON - OFFICERS' SALARIES

1. Report below the name, title and salary for the year 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 principal business unit, division or function (such as sales, administration or finance) and any other person whc 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 date change in incumbency was made
3. Utilities which are required to file similar data with the Securities and Exchange Commission, may substitute a cop of Item 4, Regulation S-K, identified as this schedule page. The substituted page(s) should be conformed to the siz of this page.

Line No.	Title (a)	Name of Officer (b)	Salary for Year Total (c)	Salary for Year Oregon (d)

See the attached Executive Compensation Table from Avista Corp.'s Proxy Statement.

EXECUTIVE COMPENSATION TABLES

Summary Compensation Table—2021

Name and Principal Position	Year	Salary(1)	Stock Awards ($)(2)	Non-Equity Incentive Plan Compensation ($)(3)	Change in Pension and Non-Qualified Deferred Compensation Earnings ($)(4)	All Other Compensation ($)(5)	Total Compensation ($)
D. P. Vermillion	2021	$769,038	$1,986,445	$ 855,587	$ 905,751	$ 60,718	$4,577,539
President & CEO	2020	$737,693	$1,778,775	$ 184,423	$2,290,317	$ 12,875	$5,004,033
	2019	$526,100	$ 602,372	$ 534,056	$ 704,492	$ 15,600	$2,382,620
M. T. Thies	2021	$461,615	$ 653,436	$ 333,818	$ 197,793	$ 17,400	$1,664,062
Executive Vice President,	2020	$452,615	$ 663,720	$ 73,550	$ 386,704	$ 17,100	$1,593,688
CFO & Treasurer	2019	$443,154	$ 558,153	$ 342,629	$ 281,832	$ 91,800	$1,717,568
J. R. Thackston	2021	$343,463	$ 428,659	$ 229,270	$ 152,208	$ 15,196	$1,168,796
Sr. Vice President &	2020	$332,692	$ 439,654	$ 49,904	$ 501,700	$ 14,611	$1,338,561
Environmental	2019	$319,692	$ 369,303	$ 247,173	$ 360,431	$ 89,516	$1,386,115
Compliance Officer							
K. J. Christie	2021	$343,461	$ 345,109	$ 229,269	$ 186,490	$ 13,050	$1,117,379
Sr. Vice President,	2020	$333,462	$ 270,784	$ 50,019	$ 384,920	$ 12,825	$1,052,011
External Affairs and							
Chief Customer Officer							
H. L. Rosentrater	2021	$343,462	$ 345,109	$ 229,269	$ 147,079	$ 13,050	$1,077,969
Sr. Vice President	2020	$329,385	$ 270,784	$ 48,408	$ 403,216	$ 12,825	$1,064,618
Energy Delivery and Shared							

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(M, D, Y) May 1, 2022	Dec. 31, 2021

STATE OF OREGON - DONATIONS OR PAYMENTS FOR SERVICES RENDERED BY PERSONS OTHER THAN EMPLOYEES AND CHARGED TO OREGON OPERATING ACCOUNTS

1. Report for each service rendered (including materials furnished incidental to the service which are impracticable of separation) by recipient and in total the aggregate of all payments made during the year where the aggregate of such payments to a recipient was $25,000 or more including fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payments for services, traffic settlements, amounts paid for general services and licenses, accruals paid to trustees of pension and other employee benefit funds, and amounts paid for construction or maintenance of plant to persons other than affiliates) to any one corporation, institution, association, firm, partnership, committee, or person (not an employee of the respondent). Indicate by an asterisk in column (c) each item that includes payments for materials furnished incidental to the service performed. Payments to a recipient by two or more companies within a single system under a cost sharing or other joint arrangement shall be considered a single item for reporting in this schedule and shall be shown in the report of the principal company in the joint arrangement (as measured by gross operating revenues) with references thereto in the reports of the other system companies in the joint arranement.
2. If more convenient, this schedule may be filled out for a group of companies considered as one system and shown only in the report of the principal company in the system, with references thereto in the reports of the other companies.

Line No.	Name of Recipient (a)	Nature of Service (b)	Amount of Payment (c)
1	MICHELS UTILITY SERVICES INC	Professional Services	7,928,709
2	MICHELS CORPORATION	Professional Services	4,262,671
3	TRAFFIC CONTROL SERVICES LLC	Professional Services	1,513,979
4	VOLT MANAGEMENT CORP	Professional Services	1,310,646
5	NPL CONSTRUCTION CO	Professional Services	1,219,250
6	INFRASOURCE SERVICES LLC	Professional Services	911,549
7	ONE CALL LOCATORS LTD	Professional Services	728,443
8	HEATH CONSULTANTS INCORPORATED	Professional Services	645,330
9	MESA PRODUCTS INC	Professional Services	440,646
10	PROFESSIONAL PIPE SERVICES	Professional Services	293,833
11	SUNRISE ENGINEERING INC	Professional Services	292,265
12	HEAD CONCRETE INC	Professional Services	280,690
13	IBM CORPORATION	Professional Services	241,815
14	POWER CITY ELECTRIC INC	Professional Services	153,860
15	INTELLITECT	Professional Services	152,388
16	HYDROMAX USA LLC	Professional Services	141,456
17	CONCENTRIC ENERGY ADVISORS INC	Professional Services	128,041
18	UTILITY SOLUTIONS PARTNERS LLC	Professional Services	118,965
19	NAGARRO INC	Professional Services	110,478
20	FUJITSU AMERICA INC	Professional Services	97,652
21	SOUTHERN CROSS CORP	Professional Services	89,326
22	POWER SYSTEMS CONSULTANTS INC	Professional Services	85,934
23	NUVODIA STAFFING LLC	Professional Services	75,512
24	CASCADE CABLE CONSTRUCTORS INC	Professional Services	68,583
25	NBC TRAFFIC CONTROL	Professional Services	68,016
26	WILLIAMS GAS PIPELINES	Professional Services	60,165
27	TIER1 INC	Professional Services	53,709
28	NUVODIA LLC	Professional Services	47,200
29	CERIUM NETWORKS	Professional Services	45,881
30	DXC TECHNOLOGY SERVICES LLC	Professional Services	44,953
31	METALS TESTING SERVICES INC	Professional Services	43,255
32	ONE CALL CONCEPTS INC	Professional Services	38,320
33	BAKER BOTTS LLP	Professional Services	34,038
34	AVCO CONSULTING INC	Professional Services	32,796
35	SUPERIOR FENCE LLC	Professional Services	30,640
36	POWER PLAN INC	Professional Services	26,844
37	GUIDEHOUSE	Professional Services	25,860
38	SOS PLUMBING & DRAIN SERVICE INC	Professional Services	25,590
	OTHER		1,145,293
			23,014,581

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

In order to help us with production of our Oregon Utility Statistics publication, please indicate:

Oregon Production Statistics (therms)	
Gas Produced	0
Gas Purchased	242,717,160
Total Receipts	242,717,160
Gas Sales	97,822,436
Gas Used by Company	16,023
Gas Delivered to Storage - Net	97,780
Sales for Resale	142,233,710
Losses and billing delay	2,547,211
Total Disbursements	242,717,160
Oregon Revenue by Service Class	
Residential Sales	66,850,834
Commercial and Industrial Sales	
Firm Sales	32,684,566
Interruptible Sales	4,269,545
Transportation	2,984,984
Total	106,789,929
Gas Delivered in Therms (Oregon)	
Residential Sales	50,565,481
Commercial and Industrial Sales	
Firm	32,235,297
Interruptible	15,021,659
Transportation	40,406,116
Total	138,228,553
Average Number of Oregon Customers	
Residential Sales	93,020
Commercial and Industrial	
Firm	11,949
Interruptible	42
Transportation	33
Total	105,044

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	May 1, 2022	Dec. 31, 2021

STATE OF OREGON - Distribution of Salaries and Wages

1. 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. Salaries and wages billed to the Respondent by an affiliated company must be assigned to the particular operating function(s) relating to the expenses.

2. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used. When 'reporting detail of other accounts, enter as many rows as necessary numbered sequentially starting with 75.01, 75.02, etc.

Line No.	Classification *(a)*	Direct Payroll Distribution *(b)*	Allocation of Payroll Charged to Clearing Accounts *(c)*	Total *(d)*
1	Electric			
2	Operation			
3	Production			
4	Transmission			
5	Regional Market			
6	Distribution			
7	Customer Accounts			
8	Customer Service and Informational			
9	Sales			
10	Administrative and General			
11	TOTAL Operation (Total of lines 3 thru 10)			
12	Maintenance			
13	Production			
14	Regional Market			
15	Transmission			
16	Distribution			
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)			
19	Total Operation and Maintenance			
20	Production (Total of lines 3 and 13)			
21	Transmission (Total of lines 4 and 14)			
22	Regional Market (Total of Lines 5 and 15)			
23	Distribution (Total of lines 6 and 16)			
24	Customer Accounts (line 7)			
25	Customer Service and Informational (line 8)			
26	Sales (line 9)			
27	Administrative and General (Total of lines 10 and 17)			
28	TOTAL Operation and Maintenance (Total of lines 20 thru 27)			
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production - Natural Gas(Including Exploration and Development)			
33	Other Gas Supply	395,488		395,488
34	Storage, LNG Terminaling and Processing			0
35	Transmission			0
36	Distribution	1,939,085		1,939,085
37	Customer Accounts	1,219,890		1,219,890
38	Customer Service and Informational	116,619		116,619
39	Sales			0
40	Administrative and General	3,324,179		3,324,179
41	TOTAL Operation (Total of lines 31 thru 40)	6,995,261		6,995,261
42	Maintenance			0
43	Production - Manufactured Gas			0
44	Production - Natural Gas(Including Exploration and Development)			0
45	Other Gas Supply			0
46	Storage, LNG Terminaling and Processing			0
47	Transmission	579,699		579,699

48	Distribution	732,945		732,945
49	Administrative and General			0
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	1,312,644		1,312,644
51	Total Operation and Maintenance	8,307,905		8,307,905
52	Other Utility Departments			0
53	Operation and Maintenance			0
54	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)			0
55	Utility Plant			0
56	Construction (By Utility Departments)			0
57	Electric Plant			0
58	Gas Plant	1,982,854		1,982,854
59	Other (provide details in footnote):			0
60	TOTAL Construction (Total of lines 68 thru 70)	1,982,854		1,982,854
61	Plant Removal (By Utility Departments)			0
62	Electric Plant			0
63	Gas Plant			
64	Other (provide details in footnote):			0
65	TOTAL Plant Removal (Total of lines 73 thru 75)			0
66	Other Accounts (Specify, provide details in footnote):			0
67				0
68				0
69	Current & Accrued Liabilities	88,794		88,794
70				0
71				0
72				0
73				0
74	TOTAL Other Accounts	88,794		88,794
75	TOTAL SALARIES AND WAGES	10,379,553		10,379,553

AVISTA

2021 ANNUAL REPORT

ONWARD

Delivering Better Energy for Life

Avista improves lives through innovative energy solutions. And we place those we serve at the center of everything we do. Throughout these extraordinary times, every day our employees remain devoted to driving onward to fulfill our commitments.

To Our SHAREHOLDERS,

With each passing day, it's clear that our lives are forever changed. Amidst this constantly evolving pandemic landscape, our mantra at Avista continues to be—Onward. Every day we challenge ourselves to press onward to define our new normal and deliver on our commitments to all our stakeholders.

Like many companies, we faced some headwinds in 2021, including uncertainties surrounding virus variants and vaccine mandates. Yet we remain steadfast in our focus to provide safe, reliable and affordable energy, which is vital to our customers and communities; to promote equity, inclusion and diversity; and to successfully execute on our strategies.

Deploying Capital Wisely

To help achieve our goals, we increased our capital budget to $450 million. We've strategically deployed funds to enhance reliability and resiliency for our customers, bolster our system to withstand the severe weather events we continue to experience, and harden our grid against wildfires.

Washington customers are using information from smart electric meters and natural gas modules to better manage their energy usage. And proactive budget alerts are eliminating surprises when their bill arrives. Because we put customer benefits front and center, we received full cost recovery on one of Avista's largest capital projects in company history. Collaboration with stakeholders in Washington also resulted in legislation that provides the option to file multi-year rate plans between two to four years.

Onward with Clean Energy Progress

Avista was the first utility to file its Clean Energy Implementation Plan in Washington – it's a road map of actions we intend to take to achieve our clean energy goals. In 2021, Avista set a new aspirational natural gas goal of being carbon neutral by 2045, with a 30% reduction of greenhouse gas emissions by 2030. We're also making solid progress toward achieving our aspirational goal to serve customers with 100% clean electricity by 2045 and carbon-neutral resources by 2027.

In March 2022, we officially joined the Western Energy Imbalance Market. This allows us to efficiently share renewable energy across a regional market to help reduce resource costs for our customers, while addressing concerns about the variability and reliability of renewables on the grid. Plus, two new agreements with Chelan County PUD add more renewable hydropower to our electric generation portfolio.

Onward with Innovation

Achieving the clean energy future we all want requires new innovations. The Catalyst building, adjacent Scott Morris Center for Energy Innovation, and the Eco-District shared energy model that powers both buildings demonstrate Avista's long history of innovation. Our unique approach involves our utility partnering with building operators to run grid-friendly buildings that leverage the existing grid to provide clean, reliable energy, at the most affordable cost. In fact, we've launched a new non-regulated, non-utility subsidiary and partnership called Edo to replicate this model so that others can benefit from what we're doing.

Here's another game changer. Avista's Energy Innovation Lab is using a real-time grid simulator to help us fast-track the pace of innovation and accelerate our ability to test new ideas and deploy them with confidence at utility-scale.

Innovations like these maintain Avista's reputation as an industry thought leader.

Powering Onward

I salute our employees. Such progress would be impossible without the dedication and determination of our employees who work so diligently to fulfill our mission.

It hasn't been easy. And challenges remain. Yet as I look to the horizon, I am confident that no matter what the future brings, together we have what it takes to drive onward to fulfill our commitments to all we serve—our customers, our communities, our employees, and you.

Dennis Vermillion
President and Chief Executive Officer

Financial and Operating Highlights

Electricity Generation Resource Mix

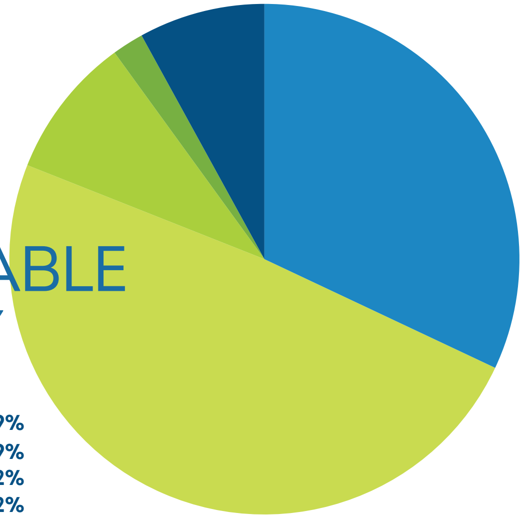
As of Dec. 31, 2021 - Excludes AEL&P

CLEAN ENERGY GOAL

Avista has set goals to serve its customers with 100% clean electricity by 2045 and to have a carbon-neutral supply of electricity by the end of 2027. Avista also set a natural gas goal of being carbon neutral by 2045, with a 30% reduction of greenhouse gas emissions by 2030.

Avista was founded on clean, renewable hydro power in 1889, and the company has a long-standing history of providing clean, reliable and affordable energy to the customers and communities it serves.

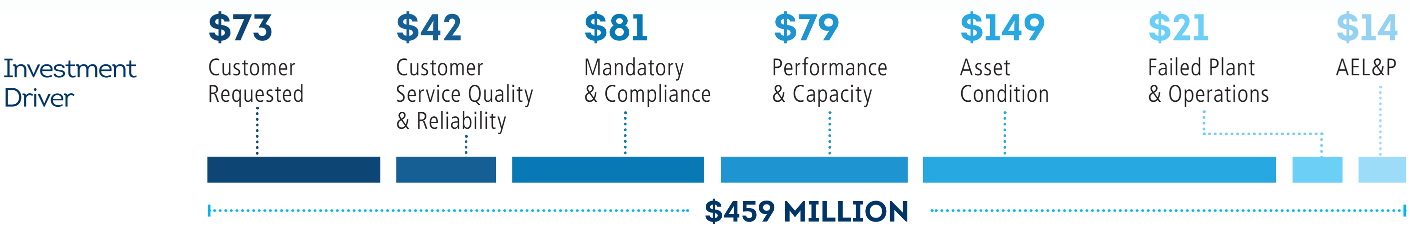
60% RENEWABLE ENERGY



Hydro	**49%**
Wind	**9%**
Biomass	**2%**
Natural Gas	**32%**
Coal	**8%**

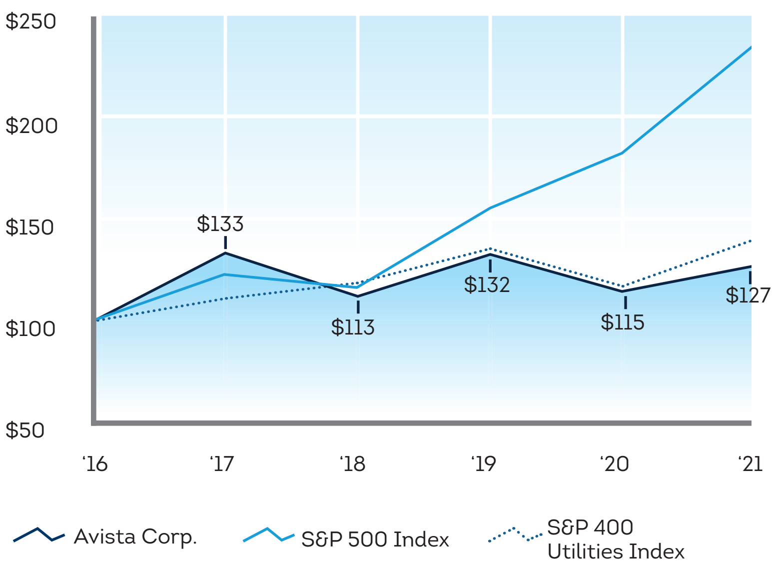
2022 Capital Budget

Total capital budget $459 million ($in millions)



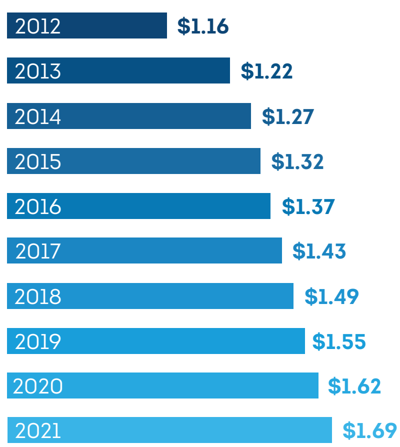
Total Shareholder Return

Assumes $100 was invested in Avista Corp. and each index on Dec. 31, 2016, and that all dividends were reinvested when paid.



Common Stock Dividends Paid by Avista Corp.

Annualized Dividend (paid in dollars)



Avista Corp.'s board of directors raised the dividend in each of the last 19 years, reflecting their confidence in the financial strength of the company.

(dollars in thousands except statistics and per share amounts or as otherwise indicated)

	2021	2020	2019
Financial Results			
Operating revenues	$ 1,438,936	$ 1,321,891	$ 1,345,622
Operating expenses	1,210,704	1,089,191	1,135,233
Income from operations	228,232	232,700	210,389
Net income attributable to Avista Corp. shareholders	147,334	129,488	196,979
Total earnings per common share attributable to Avista Corp. shareholders—diluted	2.10	1.90	2.97
Dividends paid per common share	1.69	1.62	1.55
Book value per common share	$ 30.14	$ 29.31	$ 28.87
Average common shares outstanding	69,951	67,962	66,205
Return on average Avista Corp. stockholders' equity	7.1 %	7.1 %	10.5 %
Common stock closing price	$ 42.49	$ 40.14	$ 48.09
Operating Results			
Avista Utilities			
Retail electric revenues	$ 835,118	$ 792,163	$ 799,941
Retail kWh sales (in millions)	8,796	8,435	8,645
Retail electric customers at year-end	405,622	400,018	392,828
Wholesale electric revenues	$ 89,768	$ 77,277	$ 73,232
Wholesale kWh sales (in millions)	2,461	2,680	2,787
Sales of fuel	$ 63,673	$ 28,773	$ 48,040
Other electric revenues	36,288	30,149	28,995
Decoupling (electric)	(19,525)	(4,361)	8,699
Deferrals and amortizations for rate refunds to customers	1,730	3,539	3,141
Retail natural gas revenues	$ 330,020	$ 315,677	$ 293,861
Wholesale natural gas revenues	113,277	104,910	135,039
Transportation and other natural gas revenues	15,872	12,951	16,049
Decoupling (natural gas)	12,890	547	915
Deferrals and amortizations for rate refunds to customers	1,254	1,797	1,368
Total therms delivered (in thousands)	901,279	1,091,027	1,165,903
Retail natural gas customers at year-end	372,025	366,836	361,495
Net income attributable to Avista Corp. shareholders	$ 125,558	$ 124,810	$ 183,977
Alaska Electric Light and Power Company			
Revenues	$ 45,366	$ 42,809	$ 37,265
Retail kWh sales (in millions)	404	385	337
Retail electric customers at year-end	17,428	17,295	17,175
Net income attributable to Avista Corp. shareholders	7,224	8,095	7,458
Other			
Revenues	$ 571	$ 1,614	$ 12,484
Net income (loss) attributable to Avista Corp. shareholders	14,552	(3,417)	5,544
Financial Condition			
Total assets	$ 6,853,583	$ 6,402,097	$ 6,082,456
Long-term debt and leases (including current portion)	2,267,554	2,132,249	2,020,011
Long-term debt to affiliated trusts	51,547	51,547	51,547
Total Avista Corp. stockholders' equity	2,154,744	2,029,726	1,939,284

Board of Directors

Julie A. Bentz, 57
Principal,
HOMR LLC
Scio, Oregon
Director since 2021

Kristianne Blake, 68
Spokane, Washington
Director since 2000

Donald C. Burke, 61
Langhorne, Pennsylvania
Director since 2011

Rebecca A. Klein, 56
Principal,
Klein Energy, LLC
Austin, Texas
Director since 2010

Sena M. Kwawu, 53
Senior Vice President,
Frontdoor, Inc.
Bellevue, Washington
Director since 2021

Scott H. Maw, 54
Seattle, Washington
Director since 2016

Scott L. Morris, 64
Chairman of the Board,
Avista Corp.
Spokane, Washington
Director since 2007

Jeffry L. Philipps, 66
Spokane, Washington
Director since 2019

Heidi B. Stanley, 65
Co-owner & Chair,
Empire Bolt & Screw Inc.
Spokane, Washington
Director since 2006

Dennis P. Vermillion, 60
President & CEO,
Avista Corp.
Spokane, Washington
Director since 2018

Janet D. Widmann, 55
San Francisco, California
Director since 2014

Board Committees

Governance & Corporate Responsibility Committee
Kristianne Blake — Chair
Donald C. Burke
Scott H. Maw
Janet D. Widmann

Executive Committee
Kristianne Blake
Scott L. Morris — Chair
Heidi B. Stanley
Dennis P. Vermillion

Audit Committee
Kristianne Blake
Donald C. Burke (Financial Expert) — Chair
Heidi B. Stanley

Compensation & Organization Committee
Rebecca A. Klein
Scott H. Maw - Chair
Jeffry L. Philipps

Finance Committee
Julie A. Bentz
Sena M. Kwawu
Scott L. Morris
Jeffry L. Philipps
Janet D. Widmann — Chair

Environmental, Technology & Operations Committee
Julie A. Bentz
Rebecca A. Klein — Chair
Sena M. Kwawu
Heidi B. Stanley

Corporate & Business Unit Officers

Dennis P. Vermillion, 60
President & CEO

Mark T. Thies, 58
Executive Vice President,
CFO & Treasurer

Kevin J. Christie, 54
Senior Vice President,
External Affairs & Chief
Customer Officer

Heather L. Rosentrater, 44
Senior Vice President, Energy
Delivery & Shared Services

Jason R. Thackston, 52
Senior Vice President, Energy
Resources & Environmental
Compliance Officer

Bryan A. Cox, 52
Vice President, Safety &
Human Resources

Gregory C. Hesler, 44
Vice President, General
Counsel, Corporate Secretary
& Chief Ethics/Compliance
Officer

Latisha D. Hill, 43
Vice President, Community &
Economic Vitality

James M. Kensok, 63
Vice President, CIO & Chief
Security Officer

Ryan L. Krasselt, 52
Vice President, Controller &
Principal Accounting Officer

David J. Meyer, 68
Vice President & Chief
Counsel for Regulatory &
Governmental Affairs

Edward D. Schlect, Jr., 61
Vice President & Chief
Strategy Officer

Constance S. Hulbert, 61
President &
General Manager,
Alaska Electric Light
& Power Co.

Ages are as of the proxy date — March 31, 2022

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE FISCAL YEAR ENDED **DECEMBER 31, 2021** OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE TRANSITION PERIOD FROM ________________ TO ________________

Commission file number 001-03701

AVISTA CORPORATION

(Exact name of Registrant as specified in its charter)

WA	91-0462470
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1411 East Mission Avenue, Spokane, WA 99202-2600
(Address of principal executive offices, including zip code)

Registrant's telephone number, including area code: 509-489-0500
Website: http://www.avistacorp.com

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Stock	AVA	NYSE

Securities registered pursuant to Section 12(g) of the Act:

Title of Class
Preferred Stock, Cumulative, Without Par Value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.
Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days: Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).
Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer	☒	Accelerated Filer	☐	Non-accelerated Filer	☐
Smaller reporting company	☐	Emerging growth company	☐		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act):
Yes ☐ No ☒

The aggregate market value of the Registrant's outstanding Common Stock, no par value (the only class of voting stock), held by non-affiliates is $2,972,676,681 based on the last reported sale price thereof on the consolidated tape on June 30, 2021.

As of January 31, 2022, 71,572,570 shares of Registrant's Common Stock, no par value (the only class of common stock), were outstanding.

Documents Incorporated By Reference

Document	Part of Form 10-K into Which Document is Incorporated
Proxy Statement to be filed in connection with the annual meeting of shareholders to be held May 12, 2022. Prior to such filing, the Proxy Statement was filed in connection with the annual meeting of shareholders held on May 11, 2021.	Part III, Items 10, 11, 12, 13 and 14

Index

Part I

Part II

Index (continued)

Part III

Part IV

* *not an applicable item in the 2021 calendar year for Avista Corp.*

Acronyms and Terms

(The following acronyms and terms are found in multiple locations within the document)

Acronym/Term	Meaning
aMW	– Average Megawatt—a measure of the average rate at which a particular generating source produces energy over a period of time
AEL&P	– Alaska Electric Light and Power Company, the primary operating subsidiary of AERC, which provides electric services in Juneau, Alaska
AERC	– Alaska Energy and Resources Company, the Company's wholly owned subsidiary based in Juneau, Alaska
AFUDC	– Allowance for Funds Used During Construction; represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period
AM&D	– Advanced Manufacturing and Development, doing business as METALfx
ASC	– Accounting Standards Codification
ASU	– Accounting Standards Update
Avista Capital	– Parent company to the Company's non-utility businesses, with the exception of AJT Mining Properties, Inc., which is a subsidiary of AERC
Avista Corp.	– Avista Corporation, the Company
Avista Utilities	– Operating division of Avista Corp. (not a subsidiary) comprising the regulated utility operations in Washington, Idaho, Oregon and Montana
BPA	– Bonneville Power Administration
Capacity	– The rate at which a particular generating source is capable of producing energy, measured in kW or MW
Cabinet Gorge	– The Cabinet Gorge Hydroelectric Generating Project, located on the Clark Fork River in Idaho
CEIP	– Clean Energy Implementation Plan, Washington
CETA	– Clean Energy Transformation Act, Washington
CPP	– Climate Protection Program, Oregon
Colstrip	– The coal-fired Colstrip Generating Plant in southeastern Montana
Cooling degree days	– The measure of the warmness of weather experienced, based on the extent to which the average of high and low temperatures for a day exceeds 65 degrees Fahrenheit (annual degree days above historic indicate warmer than average temperatures)
Coyote Springs 2	– The natural gas-fired combined-cycle Coyote Springs 2 Generating Plant located near Boardman, Oregon
COVID-19	– Coronavirus disease 2019, a respiratory illness that was declared a pandemic in March 2020
CT	– Combustion turbine
Deadband or ERM deadband	– The first $4.0 million in annual power supply costs above or below the amount included in base retail rates in Washington under the ERM in the state of Washington

Acronyms and Terms (continued)

(The following acronyms and terms are found in multiple locations within the document)

Acronym/Term	Meaning
Ecology	– The State of Washington's Department of Ecology
EIM	– Energy Imbalance Market
Energy	– The amount of electricity produced or consumed over a period of time, measured in kWh or MWh. Also, refers to natural gas consumed and is measured in dekatherms.
EPA	– Environmental Protection Agency
ERM	– The Energy Recovery Mechanism, a mechanism for accounting and rate recovery of certain power supply costs accepted by the utility commission in the state of Washington
FASB	– Financial Accounting Standards Board
FCA	– Fixed Cost Adjustment, the electric and natural gas decoupling mechanism in Idaho
FERC	– Federal Energy Regulatory Commission
GAAP	– Generally Accepted Accounting Principles
GHG	– Greenhouse gas
GS	– Generating station
Heating degree days	– The measure of the coldness of weather experienced, based on the extent to which the average of high and low temperatures for a day falls below 65 degrees Fahrenheit (annual degree days above historic indicate warmer than average temperatures)
Hydro One	– Hydro One Limited, based in Toronto, Ontario, Canada
IPUC	– Idaho Public Utilities Commission
IRP	– Integrated Resource Plan
Jackson Prairie	– Jackson Prairie Natural Gas Storage Project, an underground natural gas storage field located near Chehalis, Washington
Juneau	– The City and Borough of Juneau, Alaska
kV	– Kilovolt (1000 volts): a measure of capacity on transmission lines
kW, kWh	– Kilowatt (1000 watts): a measure of generating output or capability. Kilowatt-hour (1000 watt hours): a measure of energy produced
Lancaster Plant	– A natural gas-fired combined cycle combustion turbine plant located in Idaho
LNG	– Liquefied Natural Gas
MPSC	– Public Service Commission of the State of Montana
MW, MWh	– Megawatt: 1000 kW. Megawatt-hour: 1000 kWh

(The following acronyms and terms are found in multiple locations within the document)

Acronym/Term	Meaning
NERC	– North American Electricity Reliability Corporation
NorthWestern	– NorthWestern Corporation
Noxon Rapids	– The Noxon Rapids Hydroelectric Generating Project, located on the Clark Fork River in Montana
OPUC	– The Public Utility Commission of Oregon
PCA	– The Power Cost Adjustment mechanism, a procedure for accounting and rate recovery of certain power supply costs accepted by the utility commission in the state of Idaho
PGA	– Purchased Gas Adjustment
PGE	– Portland General Electric Company
PPA	– Power Purchase Agreement
PSE	– Puget Sound Energy, Inc.
PUD	– Public Utility District
RCA	– The Regulatory Commission of Alaska
REC	– Renewable energy credit
ROE	– Return on equity
ROR	– Rate of return on rate base
ROU	– Right-of-use lease asset
SEC	– U.S. Securities and Exchange Commission
Talen	– Talen Montana, LLC, an indirect subsidiary of Talen Energy Corporation
Therm	– Unit of measurement for natural gas; a therm is equal to approximately one hundred cubic feet (volume) or 100,000 BTUs (energy)
Watt	– Unit of measurement of electric power or capability; a watt is equal to the rate of work represented by a current of one ampere under a pressure of one volt
WUTC	– Washington Utilities and Transportation Commission

Forward-Looking Statements

From time-to-time, we make forward-looking statements such as statements regarding projected or future:

- financial performance;
- cash flows;
- capital expenditures;
- dividends;
- capital structure;
- other financial items;
- strategic goals and objectives;
- business environment; and
- plans for operations.

These statements are based upon underlying assumptions (many of which are based, in turn, upon further assumptions). Such statements are made both in our reports filed under the Securities Exchange Act of 1934, as amended (including this Annual Report on Form 10-K), and elsewhere. Forward-looking statements are all statements except those of historical fact including, without limitation, those that are identified by the use of words that include "will," "may," "could," "should," "intends," "plans," "seeks," "anticipates," "estimates," "expects," "forecasts," "projects," "predicts," and similar expressions.

Forward-looking statements (including those made in this Annual Report on Form 10-K) are subject to a variety of risks, uncertainties and other factors. Most of these factors are beyond our control and may have a significant effect on our operations, results of operations, financial condition or cash flows, which could cause actual results to differ materially from those anticipated in our statements. Such risks, uncertainties and other factors include, among others:

Utility Regulatory Risk

- state and federal regulatory decisions or related judicial decisions that affect our ability to recover costs and earn a reasonable return including, but not limited to, disallowance or delay in the recovery of capital investments, operating costs, commodity costs, interest rate swap derivatives, the ordering of refunds to customers and discretion over allowed return on investment;
- the loss of regulatory accounting treatment, which could require the write-off of regulatory assets and the loss of regulatory deferral and recovery mechanisms;

Operational Risk

- pandemics (including the current COVID-19 pandemic), which could disrupt our business, as well as the global, national and local economy, resulting in a decline in customer demand, deterioration in the creditworthiness of our customers, increases in operating and capital costs, workforce shortages, losses or disruptions in our workforce due to vaccine mandates, delays in capital projects, disruption in supply chains, and disruption, weakness and volatility in capital markets. In addition, any of these factors could negatively impact our liquidity and limit our access to capital, among other implications;
- wildfires ignited, or allegedly ignited, by Avista Corp. equipment or facilities could cause significant loss of life and property or result in liability for resulting fire suppression costs, thereby causing serious operational and financial harm;
- severe weather or natural disasters, including, but not limited to, avalanches, wind storms, wildfires, earthquakes, extreme temperature events, snow and ice storms, and the potential increasing frequency and intensity of such events due to climate change, that could disrupt energy generation, transmission and distribution, as well as the availability and costs of fuel, materials, equipment, supplies and support services;
- explosions, fires, accidents, mechanical breakdowns or other incidents that could impair assets and may disrupt operations of any of our generation facilities, transmission, and electric and natural gas distribution systems or other operations and may require us to purchase replacement power or incur costs to repair our facilities;
- explosions, fires, accidents or other incidents arising from or allegedly arising from our operations that could cause injuries to the public or property damage;
- blackouts or disruptions of interconnected transmission systems (the regional power grid);
- terrorist attacks, cyberattacks or other malicious acts that could disrupt or cause damage to our utility assets or to the national or regional economy in general, including any effects of terrorism, cyberattacks, ransomware, or vandalism that damage or disrupt information technology systems;
- work-force issues, including changes in collective bargaining unit agreements, strikes, work stoppages, the loss of key executives, availability of workers in a variety of skill areas, and our ability to recruit and retain employees;
- changes in the availability and price of purchased power, fuel and natural gas, as well as transmission capacity;
- increasing costs of insurance, more restrictive coverage terms and our ability to obtain insurance;
- delays or changes in construction costs, and/or our ability to obtain required permits and materials for present or prospective facilities;
- increasing health care costs and cost of health insurance provided to our employees and retirees;
- increasing operating costs, including effects of inflationary pressures;
- third-party construction of buildings, billboard signs, towers or other structures within our rights of way, or placement of fuel containers within close proximity to our transformers or other equipment, including overbuilding atop natural gas distribution lines;
- the loss of key suppliers for materials or services or other disruptions to the supply chain;
- adverse impacts to our Alaska electric utility (AEL&P) that could result from an extended outage of its hydroelectric generating resources or their inability to deliver energy, due to their lack of interconnectivity to any other electrical grids and the availability or cost of replacement power (diesel);
- changing river or reservoir regulation or operations at hydroelectric facilities not owned by us, which could impact our hydroelectric facilities downstream;
- change in the use, availability or abundancy of water resources and/or rights needed for operation of our hydroelectric facilities;

Cyber and Technology Risk

- cyberattacks on the operating systems that are used in the operation of our electric generation, transmission and distribution facilities and our natural gas distribution facilities, and cyberattacks on such systems of other energy companies with which we are interconnected, which could damage or destroy facilities or systems or disrupt operations for extended periods of time and result in the incurrence of liabilities and costs;
- cyberattacks on the administrative systems that are used in the administration of our business, including customer billing and customer service, accounting, communications, compliance and other administrative functions, and cyberattacks on such systems of our vendors and other companies with which we do business, resulting in the disruption of business operations, the release of private information and the incurrence of liabilities and costs;
- changes in costs that impede our ability to implement new information technology systems or to operate and maintain current production technology;
- changes in technologies, possibly making some of the current technology we utilize obsolete or introducing new cyber security risks;
- insufficient technology skills, which could lead to the inability to develop, modify or maintain our information systems;

Strategic Risk

- growth or decline of our customer base due to new uses for our services or decline in existing services, including, but not limited to, the effect of the trend toward distributed generation at customer sites;
- the potential effects of negative publicity regarding our business practices, whether true or not, which could hurt our reputation and result in litigation or a decline in our common stock price;
- changes in our strategic business plans, which could be affected by any or all of the foregoing, including the entry into new businesses and/or the exit from existing businesses and the extent of our business development efforts where potential future business is uncertain;
- wholesale and retail competition including alternative energy sources, growth in customer-owned power resource technologies that displace utility-supplied energy or that may be sold back to the utility, and alternative energy suppliers and delivery arrangements;
- entering into or growth of non-regulated activities may increase earnings volatility;
- the risk of municipalization or other forms of service territory reduction;

External Mandates Risk

- changes in environmental laws, regulations, decisions and policies, including, but not limited to, regulatory responses to concerns regarding climate change, efforts to restore anadromous fish in areas currently blocked by dams, more stringent requirements related to air quality, water quality and waste management, present and potential environmental remediation costs and our compliance with these matters;
- the potential effects of initiatives, legislation or administrative rulemaking at the federal, state or local levels, including possible effects on our generating resources, prohibitions or restrictions on new or existing services, or restrictions on greenhouse gas emissions to mitigate concerns over global climate changes;
- political pressures or regulatory practices that could constrain or place additional cost burdens on our distribution systems through accelerated adoption of distributed generation or electric-powered transportation or on our energy supply sources, such as campaigns to halt fossil fuel fired power generation and opposition to other thermal generation, wind turbines or hydroelectric facilities;
- failure to identify changes in legislation, taxation and regulatory issues that could be detrimental or beneficial to our overall business;
- policy and/or legislative changes in various regulated areas, including, but not limited to, environmental regulation, healthcare regulations and import/export regulations;

Financial Risk

- weather conditions, which affect both energy demand and electric generating capability, including the impact of precipitation and temperature on hydroelectric resources, the impact of wind patterns on wind-generated power, weather-sensitive customer demand, and similar impacts on supply and demand in the wholesale energy markets;
- our ability to obtain financing through the issuance of debt and/or equity securities, which could be affected by various factors including our credit ratings, interest rates, other capital market conditions and global economic conditions;
- changes in interest rates that affect borrowing costs, our ability to effectively hedge interest rates for anticipated debt issuances, variable interest rate borrowing and the extent to which we recover interest costs through retail rates collected from customers;
- changes in actuarial assumptions, interest rates and the actual return on plan assets for our pension and other postretirement benefit plans, which could affect future funding obligations, pension and other postretirement benefit expense and the related liabilities;
- the outcome of legal proceedings and other contingencies;
- economic conditions in our service areas, including the economy's effects on customer demand for utility services;
- economic conditions nationally may affect the valuation of our unregulated portfolio companies;
- declining energy demand related to customer energy efficiency, conservation measures and/or increased distributed generation;
- changes in the long-term climate and weather could materially affect, among other things, customer demand, the volume and timing of streamflows required for hydroelectric generation, costs of generation, transmission and distribution. Increased or new risks may arise from severe weather or natural disasters, including wildfires as well as their increased occurrence and intensity related to changes in climate;
- industry and geographic concentrations which could increase our exposure to credit risks due to counterparties, suppliers and customers being similarly affected by changing conditions;
- deterioration in the creditworthiness of our customers;

Energy Commodity Risk

- volatility and illiquidity in wholesale energy markets, including exchanges, the availability of willing buyers and sellers, changes in wholesale energy prices that could affect operating income, cash requirements to purchase electricity and natural gas, value received for wholesale sales, collateral required of us by individual counterparties and/or exchanges in wholesale energy transactions and credit risk to us from such transactions, and the market value of derivative assets and liabilities;
- default or nonperformance on the part of any parties from whom we purchase and/or sell capacity or energy;
- potential environmental regulations or lawsuits affecting our ability to utilize or resulting in the obsolescence of our power supply resources;
- explosions, fires, accidents, pipeline ruptures or other incidents that could limit energy supply to our facilities or our surrounding territory, which could result in a shortage of commodities in the market that could increase the cost of replacement commodities from other sources;

Compliance Risk

- changes in laws, regulations, decisions and policies at the federal, state or local levels, which could materially impact both our electric and gas operations and costs of operations; and
- the ability to comply with the terms of the licenses and permits for our hydroelectric or thermal generating facilities at cost-effective levels.

Our expectations, beliefs and projections are expressed in good faith. We believe they are reasonable based on, without limitation, an examination of historical operating trends, our records and other information available from third parties. There can be no assurance that our expectations, beliefs or projections will be achieved or accomplished. Furthermore, any forward-looking statement speaks only as of the date on which such statement is made. We undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New risks, uncertainties and other factors emerge from time-to-time, and it is not possible for us to predict all such factors, nor can we assess the effect of each such factor on our business or the extent that any such factor or combination of factors may cause actual results to differ materially from those contained in any forward-looking statement.

Available Information

We file annual, quarterly and current reports and proxy statements with the SEC. The SEC maintains a website that contains these documents at www.sec.gov. We make annual, quarterly and current reports and proxy statements available on our website, https://investor.avistacorp.com, as soon as practicable after electronically filing these documents with the SEC. Except for SEC filings or portions thereof that are specifically referred to in this report, information contained on these websites is not part of this report.

Part I

Item 1. Business

Company Overview

Avista Corp., incorporated in the territory of Washington in 1889, is primarily an electric and natural gas utility with certain other business ventures. Our mission is to improve our customers' lives through innovative energy solutions, safely, responsibly and affordably. Our corporate headquarters is in Spokane, Washington, the second-largest city in Washington. Spokane serves as the business, transportation, medical, industrial and cultural hub of the Inland Northwest region (eastern Washington and northern Idaho). Regional services include government and higher education, medical services, retail trade and finance. Through our subsidiary AEL&P, we also provide electric utility services in Juneau, Alaska.

As of December 31, 2021, we have two reportable business segments as follows:

- **Avista Utilities**—an operating division of Avista Corp., comprising the regulated utility operations in Washington, Idaho, Oregon and Montana. Avista Utilities provides electric distribution and transmission, and natural gas distribution services in parts of eastern Washington and northern Idaho. Avista Utilities also provides natural gas distribution service in parts of northeastern and southwestern Oregon. Avista Utilities has electric generating facilities in Washington, Idaho, Oregon and Montana. Avista Utilities also supplies electricity to a small number of customers in Montana, most of whom are employees who operate Avista Utilities' Noxon Rapids generating facility. Avista Utilities also engages in wholesale purchases and sales of electricity and natural gas as an integral part of energy resource management and its load-serving obligation.
- **AEL&P**—a regulated utility providing electric services in Juneau, Alaska that is a wholly owned subsidiary and the primary operating subsidiary of AERC.

We have other businesses, including venture fund investments, real estate investments, as well as certain other investments made by Avista Capital, which is a direct, wholly owned subsidiary of Avista Corp. These activities do not represent a reportable business segment and are conducted by various direct and indirect subsidiaries of Avista Corp.

Total Avista Corp. shareholders' equity was $2.2 billion as of December 31, 2021, which includes a $117.5 million investment in Avista Capital and a $108.5 million investment in AERC.

See "Note 24 of the Notes to Consolidated Financial Statements" for information with respect to the operating performance of each business segment (and other subsidiaries).

Human Capital

Our approach to people is a critical strategy and the priorities for this strategy include, among other things:

- developing, retaining and attracting a diverse and skilled workforce,
- providing opportunities for continuous learning, development, career growth, and movement within the Company,
- supporting and rewarding our employees through competitive pay and benefits,
- encouraging and supporting a community-minded Company culture, and
- investing in the physical, emotional and financial health and safety of our employees.

The following is an overview of some of our key human capital initiatives intended to foster the overall well-being of our employees and other stakeholders, such as our customers and business partners.

Equity, Inclusion, and Diversity

We strive to create a workplace culture that values trust and respect and helps guide our overall commitment to doing what is right and offering all employees the opportunity to enrich their lives and careers through challenging and meaningful work—all in an equal opportunity workplace that is surrounded by a supportive and inclusive environment. With a strong workplace culture as a foundation, we actively engage and listen to our employees, customers and communities in order to help measure and inform our equity, inclusion, diversity, and racial and social justice practices. Our equity, inclusion, and diversity initiatives are focused on employee recruitment, employee training and development, and employee engagement, including participation in employee resource groups. Employee resource groups are voluntary, employee led groups that foster a diverse and inclusive workplace aligned with our organizational mission, values and goals and business practices.

On December 31, 2021, Avista Utilities employed 1,809 with an employee profile of:

	Women	Under Represented Groups [a]
Bargaining Unit	3%	6%
Non-bargaining Unit	45%	9%
Executives [b]	17%	8%
Overall	29%	8%

(a) As defined by our Affirmative Action Plan and through employee self-identification.

(b) Executive is defined as vice president or higher.

Employee data represents all regular full-time and part-time employees, including temporary workers and student interns.

Bargaining Unit employees comprise 38 percent of Avista Utilities' employees.

People Development, Retention and Attraction

We strive to hire and retain talented people who are innovative and skilled so that we can continue to provide safe, reliable and affordable service to our customers and advance our Company at the same time.

Continuous learning plays a large part in fostering collaboration and innovation among our employees and is embedded throughout the Company. Our development opportunities are created to prepare our employees at all levels to ensure they have the skills, knowledge and experience to perform today and well into the future. Keeping our workforce equipped to succeed is imperative in order to meet the emerging challenges that lay ahead. We develop training that is relevant, necessary and in demand for our organization. Training may be delivered through instructor-led courses, self-service topics, computer-based learning modules, and field based, hands-on workshop models that cover the range of our operations. These programs encompass craft apprenticeship programs, engineering development programs, leadership development, communication skills, cross-functional learning and equity, inclusion and diversity topics. In addition to our internally led courses, we also provide opportunities for our employees to attend industry events and certification programs, courses or programs offered through energy related organizations such as the Western Energy Institute, the American Gas Association and the Edison Electric Institute, as well as to our local colleges and universities.

Workplace Safety

Safety is an essential part of our mission. We have a variety of programs and initiatives in place that are intended to help employees complete their work safely through heightened vigilance, hazard recognition, defensive strategies, lessons learned, human and organizational performance improvement and other tools intended to ensure resilience in varying and unpredictable conditions. We work with our employees to reinforce personal responsibility regarding safety and health, and to implement measures to create and maintain a safe work environment.

During the COVID-19 Pandemic, we have transitioned through various stages of response designed to protect the health and safety of our employees and meet compliance obligations, while continuing to provide essential services to our customers. We have focused on care and concern for our employees, customers and other key stakeholders, proactively communicating about the risks and relying on facts and credible information from our regional, state and federal health and safety organizations. This focus included providing options to employees and customers to best protect themselves from COVID-19 when engaging in our work.

Additional Information

Additional information highlighting the Company's commitments to corporate responsibility, including the Company's commitments to our environment, our people, our customers and communities and ethical governance, is available on the Company's website at www.avistacorp.com. Material on the Company's website is not part of this report.

Avista Utilities

General

At the end of 2021, Avista Utilities supplied retail electric service to approximately 406,000 customers and retail natural gas service to approximately 372,000 customers across its service territory. Avista Utilities' service territory covers 30,000 square miles with a population of 1.7 million. See "Item 2. Properties" for further information on our utility assets. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Economic Conditions and Utility Load Growth" for information on economic conditions in our service territory.

Electric Operations

General—Avista Utilities generates, transmits and distributes electricity, serving electric customers in eastern Washington and northern Idaho and a small number of customers in Montana, most of whom are employees who operate Avista Utilities' Noxon Rapids generating facility.

Avista Utilities generates electricity from facilities that we own and purchases capacity, energy and fuel for generation under long-term and short-term contracts to meet customer load obligations. We also sell electric capacity and energy, as well as surplus fuel in the wholesale market in connection with our resource optimization activities as described below.

As part of Avista Utilities' resource procurement and management operations in the electric business, we engage in an ongoing process of resource optimization, which involves the selection from available energy resources to serve our load obligations and the use of these resources to capture 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, fuel and fuel transportation. Such transactions are part of the process of matching available resources with load obligations and hedging a portion of the related financial risks. In order to implement this process, we make continuing projections of:

- electric loads at various points in time (ranging from intra-hour to multiple years) based on, among other things, estimates of customer usage and weather, historical data, contract terms, and emerging trends and climate modeling results, and
- resource availability at these points in time based on, among other things, fuel choices and fuel markets, estimates of snowpack and streamflows, availability of generating units, historic and forward market information, contract terms and experience.

On the basis of these projections, we make purchases and sales of electric capacity and energy, fuel for electric generation, and related derivative contracts to match expected resources to expected electric load requirements and reduce our exposure to electricity (or fuel) market price changes. The process of resource optimization involves scheduling and dispatching available resources as well as the following:

- purchasing fuel for generation,
- when economical, selling fuel and substituting wholesale electric purchases, and
- other wholesale transactions to capture the value of generating resources, transmission contract rights and fuel delivery (transport) capacity contracts.

This optimization process includes entering into hedging transactions to manage risks. Transactions include both physical energy contracts and related derivative instruments, and the terms range from intra-hour up to multiple years.

Avista Utilities' generation assets are interconnected through the regional transmission system and are operated on a coordinated basis to enhance load-serving capability and reliability. We acquire both long-term and short-term transmission capacity to facilitate all of our energy and capacity transactions. We provide transmission and ancillary services in eastern Washington, northern Idaho and western Montana.

Electric Requirements

Avista Utilities' peak electric native load requirement for 2021 was 1,889 MW, which occurred on June 30, 2021. In 2020, our peak electric native load was 1,721 MW, which occurred during the summer, and in 2019, it was 1,656 MW, which occurred during the summer.

Electric Resources

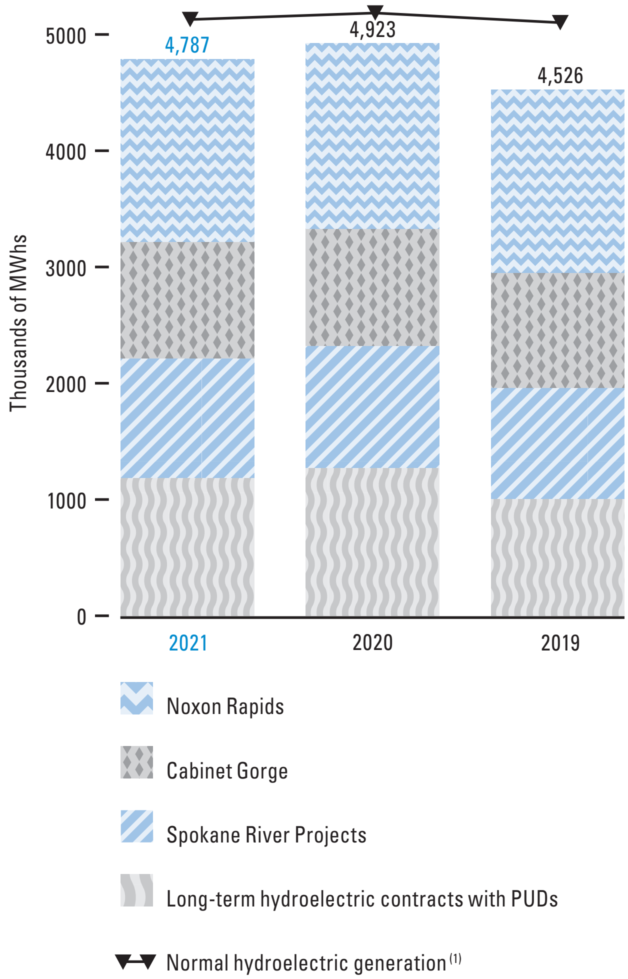
Avista Utilities has a diverse electric resource mix of Company-owned and contracted hydroelectric, thermal and wind generation facilities, and other contracts for power purchases and exchanges. As of December 31, 2021, Avista Utilities' electric generation resource mix (including contracts for power purchases) was approximately 49 percent hydroelectric, 42 percent thermal and 9 percent other renewables. See "Item 2. Properties" for detailed information on Company-owned generating facilities.

Hydroelectric Resources—Avista Utilities owns and operates Noxon Rapids and Cabinet Gorge on the Clark Fork River and six smaller hydroelectric projects on the Spokane River. Hydroelectric generation is typically our lowest cost source per MWh of electric energy and the availability of hydroelectric generation has a significant effect on total power supply costs. Under normal streamflow and operating conditions, we estimate that we would be able to meet approximately one-half of our total average electric requirements (both retail and long-term wholesale) with the combination of our hydroelectric generation and long-term hydroelectric purchase contracts with certain PUDs in the state of Washington. Our estimate of normal annual hydroelectric generation for 2022 (including resources purchased under long-term hydroelectric contracts with certain PUDs) is 579 aMW (or 5.1 million MWhs).

See "Item 2. Properties—Avista Utilities—Generation Properties" for the nameplate rating and present generating capabilities of the above hydroelectric resources.

The following graph shows Avista Utilities' hydroelectric generation (in thousands of MWhs) during the year ended December 31:

HYDROELECTRIC GENERATION



(1) "Normal" hydroelectric generation is determined by reference to the effect of upstream dam regulation on median natural water flow. Natural water flow is the flow of the rivers without the influence of dams, whereas regulated water flow takes into account any water flow changes from upstream dams due to releasing or holding back water. The calculation of "normal" varies annually due to the timing of upstream dam regulation throughout the year, as well as changes in PUD contracts.

Thermal Resources—Avista Utilities owns the following thermal generating resources:

- the combined cycle natural gas-fired CT, known as Coyote Springs 2, located near Boardman, Oregon,
- a 15 percent interest in Units 3 & 4 of Colstrip, a coal-fired boiler generating facility located in southeastern Montana; see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Colstrip" for discussion on Colstrip,
- a wood waste-fired boiler generating facility known as the Kettle Falls GS in northeastern Washington,
- a two-unit natural gas-fired CT generating facility in northeastern Spokane (Northeast CT),
- a two-unit natural gas-fired CT generating facility in northern Idaho (Rathdrum CT), and
- two small natural gas-fired generating facilities (Boulder Park GS and Kettle Falls CT).

Coyote Springs 2, which is operated by Portland General Electric Company, is supplied with natural gas under a combination of term contracts and spot market purchases, including transportation agreements with bilateral renewal rights.

Colstrip, which is operated by Talen Montana, is supplied with fuel from adjacent coal reserves under coal supply and transportation agreements. Several of the co-owners of Colstrip, including us, have a coal contract that runs through December 31, 2025. See "Item 7. Management's Discussion and Analysis—Colstrip " for discussion regarding environmental and other issues surrounding Colstrip.

The primary fuel for the Kettle Falls GS is wood waste generated as a by-product and delivered by trucks from forest industry operations within 100 miles of the plant. A combination of long-term contracts and spot purchases has provided, and is expected to meet, fuel requirements for the Kettle Falls GS.

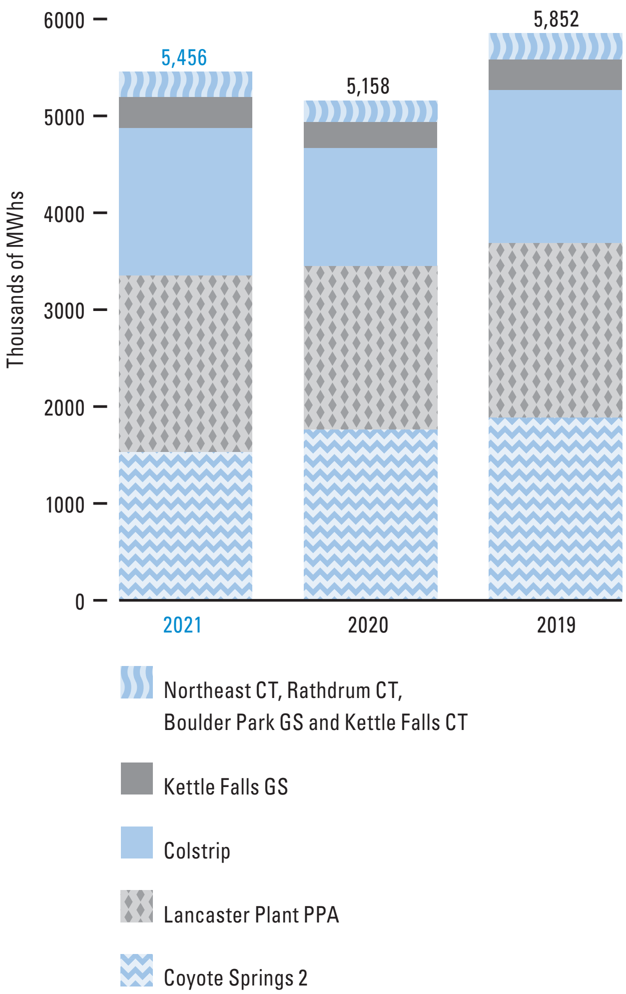
The Northeast CT, Rathdrum CT, Boulder Park GS and Kettle Falls CT generating units are primarily used to meet peaking electric requirements. We also operate these facilities when marginal costs are below prevailing wholesale electric prices. These generating facilities have access to natural gas supplies that are adequate to meet their respective operating needs.

See "Item 2. Properties—Avista Utilities—Generation Properties" for the nameplate rating and present generating capabilities of the above thermal resources.

We have the exclusive rights to all the capacity of the Lancaster Plant, a 270 MW natural gas-fired combined cycle combustion turbine plant located in northern Idaho, owned by an unrelated third-party. All of the output from the Lancaster Plant is contracted to us through 2026 under a PPA. Under the terms of the PPA, we make the dispatch decisions, provide all natural gas fuel and receive all of the electric energy output from the Lancaster Plant; therefore, we consider this plant in our baseload resources. See "Note 6 of the Notes to Consolidated Financial Statements" for further discussion of this PPA.

The following graph shows Avista Utilities' thermal generation (in thousands of MWhs) during the year ended December 31:

THERMAL GENERATION



Wind Resources—We have exclusive rights to all the capacity of Palouse Wind, a wind generation project developed, owned and managed by an unrelated third-party and located in Whitman County, Washington. The PPA expires in 2042 and requires us to acquire all of the power and renewable attributes produced by the project at a fixed price per MWh with a fixed escalation of the price over the term of the agreement. The project has a nameplate capacity of 105 MW. Generation from Palouse Wind was 360,783 MWhs in 2021, 370,142 MWhs in 2020 and 302,136 MWhs in 2019. We have an annual option to purchase the wind project beginning in December 2022. The purchase price is a fixed price per kW of in-service capacity with a fixed decline in the price per kW over the remaining 20-year term of the PPA. Under the terms of the PPA, we do not have any input into the day-to-day operation of the project, including maintenance decisions. All such rights are held by the owner.

We have exclusive rights to all of the capacity of Rattlesnake Flat Wind project developed, owned and managed by an unrelated third party and located in Adams County, Washington. The facility has a nameplate capacity of 144 MW. The PPA is a 20-year agreement that began in December 2020 and requires us to acquire all of the power and renewable attributes produced by the project at a fixed price per MWh with a fixed escalation of the price over the term of the agreement. Generation from Rattlesnake Flat Wind was 423,510 MWhs in 2021. Under the terms of the PPA, we do not have any input into the day-to-day operation of the project, including maintenance decisions. All such rights are held by the owner.

Solar Resources—We have exclusive rights to all the capacity of the Lind Solar Farm, a solar generation project developed, owned and managed by an unrelated third-party and located in Lind, Washington. The PPA expires in 2038 and requires us to acquire all the power and renewable attributes produced by the project at a fixed price per MWh. The project has a nameplate capacity of 28 MW. The facility generated 43,328 MWhs in 2021, 45,281 MWhs in 2020, and 42,346 MWhs in 2019. Under the terms of the PPA, we do not have any input into the day-to-day operation of the project, including maintenance decisions. All such rights are held by the owner.

Other Purchases, Exchanges and Sales—In addition to the resources described above, we purchase and sell power under various long-term contracts, and we also enter into short-term purchases and sales. Further, pursuant to The Public Utility Regulatory Policies Act of 1978, as amended, we are required to purchase generation from qualifying facilities. This includes, among other resources, hydroelectric projects, cogeneration projects and wind generation projects at rates approved by the WUTC and the IPUC.

See "Avista Utilities Electric Operating Statistics—Electric Operations" below for annual quantities of purchased power, wholesale power sales and power from exchanges in 2021, 2020 and 2019. See "Electric Operations" above for additional information with respect to the use of wholesale purchases and sales as part of our resource optimization process and also see "Future Resource Needs" below for the magnitude of these power purchase and sales contracts in future periods.

Avista Corp. understands that there are many coal-fired electric generating stations throughout the western United States that are scheduled for retirement in the next several years. Depending upon a variety of factors, these retirements could have an impact upon the availability and price of purchased power in, and the dynamics of, the market in which we conduct our wholesale purchases and sales. At the same time, the retirement of Colstrip Units 3 & 4, if it were effected, could increase the volume of energy that we are required to purchase in this marketplace. However, after December 31, 2025, we will be effectively prohibited by Clean Energy Transformation Act (CETA) from using energy produced by coal-fired plants to serve our retail customers in Washington, and, to the extent necessary for that purpose, we will have to obtain energy produced by other resources. See "Item 7. Management's Discussion and Analysis—Environmental Matters and Contingencies—Climate Change—Washington Legislation and Regulatory Actions—Clean Energy Transformation Act" and "Colstrip."

Hydroelectric Licenses

Avista Corp. is a licensee under the Federal Power Act (FPA) as administered by the FERC, which includes regulation of hydroelectric generation resources. Excluding the Little Falls Hydroelectric Generating Project (Little Falls), our other seven hydroelectric plants are regulated by the FERC through two project licenses. The licensed projects are subject to the provisions of Part I of the FPA. These provisions include payment for headwater benefits, condemnation of licensed projects upon payment of just compensation, and take-over by the federal government of such projects after the expiration of the license upon payment of the lesser of "net investment" or "fair value" of the project, in either case, plus severance damages. In the unlikely event that a take-over occurs, it could lead to either the decommissioning of the hydroelectric project or offering the project to another party (likely through sale and transfer of the license).

Cabinet Gorge and Noxon Rapids are under one 45-year FERC license issued in 2001. This license embodies a settlement agreement relating to project operations and resource protection and mitigation efforts over the license term. See "Item 7. Management's Discussion and Analysis—Environmental Issues and Contingencies" for discussion of dissolved atmospheric gas levels that exceed the state of Idaho and federal numeric water quality standards downstream of Cabinet Gorge during periods when we must divert excess river flows over the spillway, as well as efforts related to bull trout, a threatened species under the Endangered Species Act.

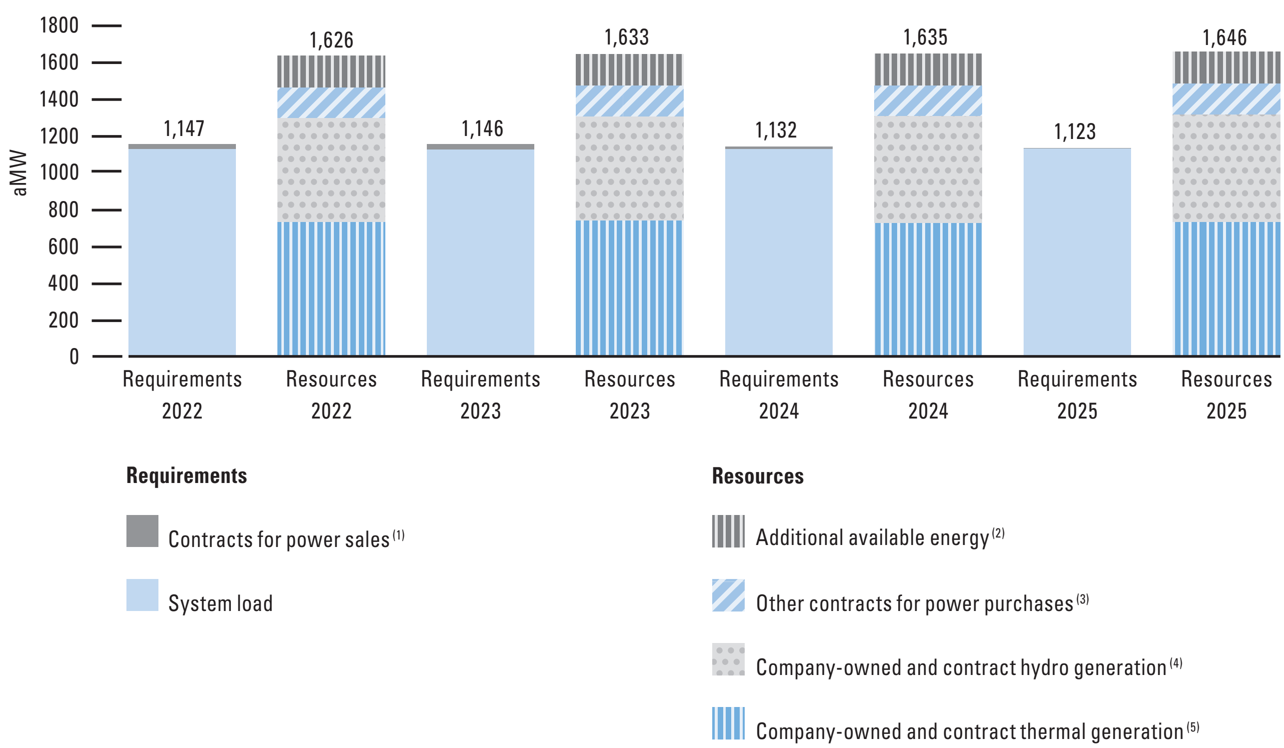
Five of our six hydroelectric projects on the Spokane River (Long Lake, Nine Mile, Upper Falls, Monroe Street and Post Falls) are under one 50-year FERC license issued in 2009 and are referred to collectively as the Spokane River Project. The license includes numerous natural and cultural resource protection measures that are subject to ongoing regulatory interpretation. The sixth, Little Falls, is operated under separate Congressional authority and is not licensed by the FERC. It is the subject of a 50-year agreement with the Spokane Tribe, signed in 1994.

Future Resource Needs

Avista Utilities has operational strategies to provide sufficient resources to meet our energy requirements under a range of operating conditions. These operational strategies consider the amount of energy needed, which varies widely because of the factors that influence demand over intra-hour, hourly, daily, monthly and annual durations. Our average hourly load was 1,113 aMW in 2021, 1,064 aMW in 2020 and 1,081 aMW in 2019.

The following graph shows our forecast of our average annual energy requirements and our available resources for 2022 through 2025:

FORECASTED ELECTRIC ENERGY REQUIREMENTS AND RESOURCES



(1) The contracts for power sales decrease due to certain contracts expiring in each of these years. We are evaluating the future plan for the additional resources made available due to the expiration of these contracts.

(2) The combined maximum capacity of Boulder Park GS, Kettle Falls CT, Northeast CT and Rathdrum CT is 278 MW, with estimated available energy production as indicated for each year.

(3) Other contracts for power purchases includes power purchase agreements for solar and wind energy.

(4) The forecast assumes near normal hydroelectric generation.

(5) Includes the Lancaster Plant PPA. Excludes Boulder Park GS, Kettle Falls CT, Northeast CT and Rathdrum CT, as these are considered peaking facilities and are generally not used to meet our base load requirements.

We are required to file an Integrated Resource Plan (IRP) with the WUTC and IPUC every two years. The WUTC and IPUC review the IRP and give the public the opportunity to comment. The WUTC and IPUC do not approve or disapprove of the content in the IRP; rather, they acknowledge that the IRP was prepared in accordance with applicable standards if that is the case. The IRP details projected growth in demand for energy and the new resources needed to serve customers over the next 20 years. We regard the IRP as a tool for resource evaluation, rather than an acquisition plan for a particular project.

In April 2021, we filed our 2021 Electric IRP with the WUTC and the IPUC. Later that same month, we filed an amended IRP to include the results of the 2020 Renewable Request for Proposal (RFP).

Highlights of the 2021 IRP include the following expectations and/or assumptions:

- We have adequate resources between owned and contractually controlled generation, when combined with conservation and market purchases, to meet customer demand through October 2026. Our first long-term capacity deficit, net of energy efficiency, begins in October 2026 and is 247 MW by January 2027.
- The resource strategy reduces greenhouse gas emissions between 80–90 percent from present levels.
- We anticipate customer load growth of 0.3 percent per year.
- Assumes Colstrip will exit the portfolio by 2025 (see "Item 7. Management's Discussion and Analysis of Financial Condition—Environmental Issues and Contingencies" for further discussion of Colstrip in relation to the Washington Clean Energy Transformation Act).
- New natural gas-fired peaking units are the most economic means to meet the capacity shortfall in 2027 since long-term energy storage is not yet available at a cost effective price.
- Demand response programs begin in 2025 and grow to 72 MW by 2045.
- Our first new renewable resource identified in the IRP is in 2025, as a wind project located in Montana. Actual resource selection will be determined by a future RFP.

The resource strategy embodied in the IRP is intended to move us closer to achieving our corporate clean electricity goal to provide customers with 100 percent net clean electricity by 2027. Net clean energy is defined as either 100 percent non-carbon emitting resources or investing in or acquiring carbon offsets to net-out emissions created from carbon emitting resources. The addition of natural gas peaking units in 2027 would require us to purchase carbon offsets.

We are subject to the Washington State Energy Independence Act, which requires us to obtain a portion of our electricity from qualifying renewable resources or through purchase of RECs and acquiring all cost effective conservation measures. Future generation resource decisions will be affected by legislation for restrictions on greenhouse gas emissions and renewable energy requirements.

See "Item 7. Management's Discussion and Analysis of Financial Condition—Environmental Issues and Contingencies" and "Colstrip" for information related to existing and proposed laws and regulations, and issues relating to Colstrip.

Additional generating resources that we will require will either be owned by us or be owned by other parties who will sell the capacity and energy to us under PPAs. The decision as to ownership will be made as to each project at the appropriate time and will depend on, among other things, the type of project and the related economics, including tax and ratemaking treatment.

Request for Proposals for Renewable Energy

We sought proposals from renewable energy project developers who are capable of constructing, owning and operating up to 120 aMWs whether through one or multiple proposals with a minimum net annual output of 20 aMW. We did not consider a self-build option for this facility or facilities.

Our intent was to secure the output from renewable generation resources, including electricity, capacity and associated environmental attributes. Our interest in acquiring renewable energy resources was to offset market purchases and fossil-fuel thermal generation. Final bidders were selected for review in October 2020 and the Company successfully negotiated a fixed cost contract for a 5 percent share of output (88 MW / 51 aMW) of Chelan PUD's Chelan hydro system (Rocky Reach and Rock Island hydro projects) signed in March 2021 and an additional contract for a 10 percent share (177 MW) in December 2021. The December 2021 contract starts with a 5 percent share from 2026 to 2030, and increases to a 10 percent share from 2031 to 2045.

Clean Energy Goals

In April 2019, we announced a goal to serve our customers with 100 percent clean electricity by 2045 and to have a carbon-neutral supply of electricity by the end of 2027. To help achieve our goals and add to our clean electricity portfolio, in the last three years, we have implemented renewable energy projects on behalf of our customers including entering into PPAs for the Solar Select project (28 MW) in Lind, Washington and the Rattlesnake Flat Wind project (144 MW) in Adams County, Washington. We also entered into two power purchase contracts with Chelan County Public Utility District for a percentage share of the output of their Rocky Reach and Rock Island hydro projects for 22 years starting in 2024 (88-264 MW). These resources are in addition to our existing clean hydroelectric generation, biomass generation, and additional wind and solar projects.

To achieve our clean energy goals, we expect that energy storage and other technologies, which are either not currently available or are not cost-effective under the lowest reasonable cost regulatory standard, will advance such that it will allow us to meet our goals while also maintaining reliability and affordability for our customers. If the required technology is not available or not affordable in the future, we may not meet our goals in the desired timeframe. Meeting our clean energy goals may also require accommodation from regulatory agencies insofar as we may need to acquire emission offsets to meet our goals. See the discussion in Item 1 under "Electric Resources" for more information on our existing clean electricity sources and efforts to achieve these goals. See "Item 7. Management's Discussion and Analysis of Financial Condition—Environmental Issues and Contingencies" for further discussion on clean energy, including applicable regulations.

Wildfire Resiliency Plan

We are implementing additional measures to enhance our ability to mitigate the potential for, and impact of, wildfires within our service territories. Building on prevention and response strategies that have been in place for many years, we created a new comprehensive 10-year Wildfire Resiliency Plan that includes improved defense strategies and operating practices for a more resilient system. This plan will be periodically updated and informed by observed experience as well as changes in observed landscape and climatic conditions.

We have developed the Wildfire Resiliency Plan through a series of internal workshops, industry research and engagement with state and local fire agencies. Improvements to infrastructure and operational practices were identified as key components to the plan. These key components are categorized into the following categories: grid hardening, vegetation management, situational awareness, operations and emergency response, and worker and public safety.

We expect to spend approximately $330 million implementing the plan components over the life of the 10-year plan. The IPUC and WUTC have approved deferral of certain costs of the wildfire resiliency plan and seek recovery in future rate filings.

See "Note 22 of the Notes to Consolidated Financial Statements" for further discussion on wildfires.

Natural Gas Operations

General—Avista Utilities provides natural gas distribution services to retail customers in parts of eastern Washington, northern Idaho, and northeastern and southwestern Oregon.

Market prices for natural gas, like other commodities, can be volatile. Our natural gas procurement strategy is to provide a reliable supply to our customers with some level of price certainty. We procure natural gas from various supply basins and over varying time periods. The resulting portfolio is a diversified mix of forward fixed price purchases, index and spot market purchases, and utilizing physical and financial derivative instruments. We also use natural gas storage to support high demand periods and to procure natural gas when prices may be lower. Securing prices throughout the year and even into subsequent years provides a level of price certainty and can mitigate price volatility to customers between years.

Weather is a key component of our natural gas customer load. This load is highly variable and daily natural gas loads can differ significantly from the monthly forecasted load projections. We make continuing projections of our natural gas loads and assess available natural gas resources. On the basis of these projections, we plan and execute a series of transactions to hedge a portion of our customers' projected natural gas requirements through forward market transactions and derivative instruments. These transactions may extend for multiple years into the future. We also leave a portion of our natural gas supply requirements unhedged for purchase in the short-term spot markets.

Our purchase of natural gas supply is governed by our procurement plan and is reviewed and approved annually by the Risk Management Committee (RMC), which is comprised of certain officers and other management personnel. Once approval is received, the plan is implemented and monitored by our gas supply and risk management groups.

The plan's progress is also presented to the WUTC and IPUC staff in semi-annual meetings, and updates are given to the OPUC staff quarterly. The RMC is provided with an update on plan results and changes in their monthly meetings. These activities provide transparency for the natural gas supply procurement plan. Any material changes to the plan are documented and communicated to RMC members.

As part of the process of balancing natural gas retail load requirements with resources, we engage in the wholesale purchase and sale of natural gas. We plan for sufficient natural gas delivery capacity to serve our retail customers for a theoretical peak day event. We generally have more pipeline and storage capacity than what is needed during periods other than a peak day. We optimize our natural gas resources by using market opportunities to generate economic value that helps mitigate fixed costs. Wholesale sales are delivered through wholesale market facilities outside of our natural gas distribution system. Natural gas resource 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.

We also provide distribution transportation service to qualified, large commercial and industrial natural gas customers who purchase natural gas through third-party marketers. For these customers, we receive their purchased natural gas from such third-party marketers into our distribution system and deliver it to the customers' premises. These customers generally pay the same rates as other customers in the same class, without any charge for the cost of the natural gas delivered.

Optimization transactions that we engage in throughout the year are included in our annual purchased gas cost adjustment filings with the various commissions and are subject to review for prudence during this process.

Clean Energy Goals—In April 2021, we announced an aspirational goal to reduce carbon emissions for natural gas 30 percent by 2030 and 100 percent by 2045. Examples of carbon emissions reduction strategies include the following:

- diversify or transition from fossil fuel-based natural gas to renewable natural gas,
- reduce natural gas consumption via conservation, energy efficiency and new technologies, and
- purchase carbon offsets as necessary.

Achieving the carbon emission reductions for the natural gas system will involve various pathways. The initial primary pathways include renewable natural gas (RNG), energy efficiency, customer voluntary RNG and carbon offset programs. See "Item 7. Management's Discussion and Analysis of Financial Condition—Environmental Issues and Contingencies" for further discussion on clean energy, including applicable regulations.

Natural Gas Supply—Avista Utilities purchases all of its natural gas in wholesale markets. We are connected to multiple supply basins in the western United States and Canada through firm capacity transportation rights on six different pipeline networks. Access to this diverse portfolio of natural gas resources allows us to make natural gas procurement decisions that benefit our natural gas customers. These interstate pipeline transportation rights provide the capacity to serve approximately 25 percent of peak natural gas customer demands from domestic sources and 75 percent from Canadian sourced supply. Natural gas prices in the Pacific Northwest are affected by global energy markets, as well as supply and demand factors in other regions of the United States and Canada. Future prices and delivery constraints may cause our resource mix to vary.

Natural Gas Storage—Avista Utilities owns a one-third interest in Jackson Prairie, an underground aquifer natural gas storage field located near Chehalis, Washington. Jackson Prairie has a total peak day deliverability of 12 million therms, with a total working natural gas capacity of 256 million therms. As an owner, our share is one-third of the peak day deliverability and total working capacity. We also contract for additional storage capacity and delivery at Jackson Prairie from Northwest Pipeline for a portion of their one-third share of the storage project.

We optimize our natural gas storage capacity throughout the year by executing transactions that capture favorable market price spreads.

Natural gas buyers identify opportunities to purchase lower cost natural gas in the immediate term to inject into storage, and then sell the gas in a forward market to be withdrawn at a later time. The reverse of this type of transaction also occurs. These transactions lock in incremental value for customers. Jackson Prairie is also used as a variable peaking resource, and to protect from extreme daily price volatility during cold weather or other events affecting the market.

Future Resource Needs—In April 2021, we filed our 2021 Natural Gas IRP with the WUTC, the IPUC and the OPUC. The IRP details projected growth in demand for energy and the new resources needed to serve customers over the next 20 years. We regard the IRP as a tool for resource evaluation, rather than an acquisition plan for a particular project. The IPUC and OPUC have formally acknowledged our IRP; the WUTC is still processing the IRP.

Highlights of the 2021 natural gas IRP include the following expectations and/or assumptions:

- We anticipate having sufficient natural gas resources during the 20-year planning horizon.
- Due to expected carbon legislation at the state levels through a cap and reduce mechanism (Oregon) or a social cost of carbon tax mechanism (Washington), we expect our retail natural gas rates to include a carbon price adder in Oregon and Washington, but not in Idaho.
- Regional supply constraints are beginning to increase in their likelihood causing prices to act in a more volatile fashion. This volatility in pricing paired with supply side resource availability has made our procurement plan an increasingly important piece to manage customer rates, diversity of supply and peak day demand.
- LNG exports, power generation and exports to Mexico will continue to add demand for natural gas.
- We expect lower use per customer and an increased amount of demand side management (DSM). The combination of low-priced natural gas in addition to carbon fees or other programs has led to a higher potential for DSM measures.
- We view renewable natural gas and low carbon fuels as an important component of our corporate environment strategy and decarbonization goals.

We will monitor these assumptions on an on-going basis and adjust our resource requirements accordingly.

We are required to file a natural gas IRP every two years and we anticipate our next IRP to be filed in 2023.

Utility Regulation

General—As a public utility, Avista Corp. is subject to regulation by state utility commissions for retail electric and natural gas rates, accounting, the issuance of securities and other matters. The retail electric and natural gas operations are subject to the jurisdiction of the WUTC, IPUC, OPUC and MPSC. Approval of the issuance of securities is not required from the MPSC. We are also subject to the jurisdiction of the FERC for licensing of hydroelectric generation resources, and for electric transmission services and wholesale sales.

Since Avista Corp. is a "holding company" (in addition to being itself an operating utility), we are also subject to the jurisdiction of the FERC under the Public Utility Holding Company Act of 2005, which imposes certain reporting and record-keeping requirements on Avista Corp. and its subsidiaries. We and our subsidiaries are required to make books and records available to the FERC and the state utility commissions. In addition, upon the request of any jurisdictional state utility commission, the FERC would have the authority to review assignment of costs of non-power goods and administrative services among us and our subsidiaries. The FERC has the authority generally to require that rates subject to its jurisdiction be just and reasonable and in this context would continue to be able to, among other things, review transactions of any affiliated company.

Our rates for retail electric and natural gas services (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are generally determined on a "cost of service" basis.

Retail rates are designed to provide an opportunity for us to recover allowable operating expenses and earn a return of and a reasonable return on "rate base." Rate base is generally determined by reference to the original cost (net of accumulated depreciation) of utility plant in service, subject to various adjustments for deferred income taxes and other items. Over time, rate base is increased by additions to utility plant in service and reduced by depreciation and write-offs as authorized by the utility commissions. Our operating expenses and rate base are allocated or directly assigned to five regulatory jurisdictions: electric in Washington and Idaho, and natural gas in Washington, Idaho and Oregon. In general, requests for new retail rates are made on the basis of revenues, operating expenses and net investment for a test year that ended prior to the date of the request, subject to possible adjustments, which differ among the various jurisdictions, designed to reflect the expected revenues, operating expenses and net investment during the period new retail rates will be in effect. The retail rates approved by the state commissions in a rate proceeding may not provide sufficient revenues to provide recovery of costs and a reasonable return on investment for a number of reasons, including, but not limited to, ongoing capital expenditures and unexpected changes in revenues and expenses following the time new retail rates are requested in the rate proceeding (known as "regulatory lag"), the denial by the commission of recovery, or timely recovery, of certain expenses or investment and the limitation by the commission of the authorized return on investment. In 2021, Washington enacted a multi-year rate plan and performance-based rate making. See "Item 7. Management's Discussion and Analysis—Regulatory Matters—General Rate Cases" for further information.

Our rates for wholesale electric sales and electric transmission services, as well as certain natural gas transportation services, are based on either "cost of service" principles or market-based rates as set forth by the FERC. See "Notes 1, 12 and 23 of the Notes to Consolidated Financial Statements" for additional information about regulation, depreciation and deferred income taxes.

General Rate Cases—Avista Utilities regularly reviews the need for electric and natural gas rate changes in each state in which we provide service. See "Item 7. Management's Discussion and Analysis—Regulatory Matters—General Rate Cases" for information on general rate case activity.

Power Cost Deferrals—Avista Utilities defers the recognition in the income statement of certain power supply costs that vary from the level currently recovered from our retail customers as authorized by the WUTC and the IPUC. See "Item 7. Management's Discussion and Analysis—Regulatory Matters—Power Cost Deferrals and Recovery Mechanisms" and "Note 23 of the Notes to Consolidated Financial Statements" for information on power cost deferrals and recovery mechanisms in Washington and Idaho.

Purchased Gas Adjustments (PGA)—Under established regulatory practices in each state, Avista Utilities defers the recognition in the income statement of the natural gas costs that vary from the level currently recovered from our retail customers as authorized by each of our jurisdictions. See "Item 7. Management's Discussion and Analysis—Regulatory Matters—Purchased Gas Adjustments" and "Note 23 of the Notes to Consolidated Financial Statements" for information on natural gas cost deferrals and recovery mechanisms in Washington, Idaho and Oregon.

Decoupling Mechanisms—Decoupling (also known as FCA in Idaho) is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. In each of its jurisdictions, Avista Utilities' 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" usage, rather than being based on actual usage. 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. See "Item 7. Management's Discussion and Analysis—Regulatory Matters—Decoupling and Earnings Sharing Mechanisms" for further discussion of these mechanisms.

Federal Laws Related to Wholesale Competition

Federal law promotes practices that foster competition in the electric wholesale energy market. The FERC requires electric utilities to transmit power and energy to or for wholesale purchasers and sellers, and requires electric utilities to enhance or construct transmission facilities to create additional transmission capacity for the purpose of providing these services. Public utilities (through subsidiaries or affiliates) and other entities may participate in the development of independent electric generating plants for sales to wholesale customers.

Public utilities operating under the FPA are required to provide open and non-discriminatory access to their transmission systems to third parties and establish an Open Access Same-Time Information System to provide an electronic means by which transmission customers can obtain information about available transmission capacity and purchase transmission access. The FERC also requires each public utility subject to the rules to operate its transmission and wholesale power merchant operating functions separately and to comply with standards of conduct designed to ensure that all wholesale users, including the public utility's power merchant operations, have equal access to the public utility's transmission system. Our compliance with these standards has not had any substantive impact on the operation, maintenance and marketing of our transmission system or our ability to provide service to customers.

See "Item 7. Management's Discussion and Analysis—Competition" for further information.

Regional Transmission Planning

Beginning with FERC Order No. 888 and continuing with subsequent rulemakings and policies, the FERC has encouraged better coordination and operational consistency aimed to capture efficiencies that might otherwise be gained through the formation of a Regional Transmission Organization or an independent system operator (ISO).

The Company currently meets its FERC requirements to coordinate transmission planning activities with other regional entities through NorthernGrid. Launched January 1, 2020, NorthernGrid is an association of all major transmission providers throughout the Pacific Northwest and Intermountain West, with facilities in California, Idaho, Montana, Oregon, Utah, Washington and Wyoming. Through its participation in NorthernGrid, the Company is able to meet the regional transmission planning requirements of FERC Order Nos. 890 and 1000, and their follow-on orders. NorthernGrid and its members also work with other western organizations, including WestConnect and the California Independent System Operator (CAISO), to address broader interregional planning. Neither the costs nor requirements of participating in NorthernGrid's coordinated transmission planning activities are expected to materially impact the Company's operations or financial performance.

Regional Energy Markets

The CAISO operates the Western Energy Imbalance Market (EIM) in the western United States. Most investor-owned utilities in the Pacific Northwest are either participants in the Western EIM or plan to integrate into the market in the near future. The Company has announced its decision to participate in the Western EIM and is slated to commence EIM operations by March 2022. The decision to join the Western EIM was based on a number of factors, including the amount of expected variable generating resources the Company will need to integrate within its balancing authority area in the foreseeable future, and the expected costs and benefits associated with joining the Western EIM. The EIM, among other things, facilitates regional load balancing by allowing certain generating plants to receive automated dispatch signals from the CAISO in five-minute intervals.

Reliability Standards

Among its other provisions, the U.S. Energy Policy Act provides for the implementation of mandatory reliability standards and authorizes the FERC to assess penalties for non-compliance with these standards and other FERC regulations.

The FERC has certified the NERC as the single Electric Reliability Organization authorized to establish and enforce reliability standards and delegate authority to regional entities for the purpose of establishing and enforcing reliability standards, including but not limited to cybersecurity measures. The FERC approves NERC Reliability Standards, including western region standards that make up the set of legally enforceable standards for the United States bulk electric system. We are required to self-certify our compliance with these standards on an annual basis and undergo regularly scheduled periodic reviews by the NERC and its regional entity, the Western Electricity Coordinating Council (WECC). Failure to comply with NERC reliability standards could result in substantial financial penalties. We have a robust internal compliance program in place to manage compliance activities and mitigate the risk of potential noncompliance with these standards. We do not expect the costs associated with compliance with these standards to have a material impact on our financial results.

As both a balancing authority and transmission operator, the Company must operate under the oversight of a reliability coordinator per NERC reliability standards. RC West is the reliability coordinator of record for 41 balancing authorities and transmission operators in the Western Interconnection, including Avista Corp. RC West oversees grid compliance with federal and regional grid standards, and can determine measures to prevent or mitigate system emergencies in day-ahead or real-time operations.

Vulnerability to Cyberattack

The energy sector, particularly electric and natural gas utility companies in the United States and abroad, have become the subject of cyberattacks and ransomware attacks with increased frequency. The Company's administrative and operating networks are targeted by hackers on a regular basis.

A successful attack on the Company's administrative networks could compromise the security and privacy of data, including operating, financial and personal information. A successful attack on the Company's operating networks could impair the operation of the Company's electric and/or natural gas utility facilities, possibly resulting in the inability to provide electric and/or natural gas service for extended periods of time.

The Company continually reinforces and updates its defensive systems and is in compliance with NERC's reliability standards. See "Reliability Standards," "Item 1A. Risk Factors—Cyber and Technology Risk Factors" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Enterprise Risk Management—Cyber and Technology Risks" for further information.

Avista Utilities Electric Operating Statistics

Years Ended December 31,

	2021	2020	2019
Electric Operations			
Operating Revenues (Dollars in Thousands):			
Residential	$ 394,717	$ 377,785	$ 369,102
Commercial	326,173	303,972	317,589
Industrial	106,756	103,103	105,802
Public street and highway lighting	7,472	7,303	7,448
Total retail	835,118	792,163	799,941
Wholesale	89,768	77,277	73,232
Sales of fuel	63,673	28,773	48,040
Other	36,288	30,149	28,995
Alternative revenue programs	(19,525)	(4,361)	8,699
Deferrals and amortizations for rate refunds to customers	1,730	3,539	3,141
Total electric operating revenues	$ 1,007,052	$ 927,540	$ 962,048
Energy Sales (Thousands of MWhs):			
Residential	3,955	3,807	3,766
Commercial	3,158	2,995	3,170
Industrial	1,666	1,615	1,691
Public street and highway lighting	17	18	18
Total retail	8,796	8,435	8,645
Wholesale	2,461	2,680	2,787
Total electric energy sales	11,257	11,115	11,432
Energy Resources (Thousands of MWhs):			
Hydro generation (from Company facilities)	3,598	3,651	3,520
Thermal generation (from Company facilities)	3,635	3,474	4,054
Purchased power	4,954	4,922	4,833
Power exchanges	(398)	(446)	(504)
Total power resources	11,789	11,601	11,903
Energy losses and Company use	(532)	(486)	(471)
Total energy resources (net of losses)	11,257	11,115	11,432
Number of Retail Customers (Average for Period):			
Residential	356,387	350,669	345,064
Commercial	44,110	43,497	42,930
Industrial	1,205	1,277	1,305
Public street and highway lighting	666	639	612
Total electric retail customers	402,368	396,082	389,911
Residential Service Averages:			
Annual use per customer (KWh)	11,098	10,857	10,914
Revenue per KWh (in cents)	9.98	9.92	9.80
Annual revenue per customer	$ 1,107.55	$ 1,077.33	$ 1,069.66
Average Hourly Load (aMW)	1,113	1,064	1,081

Avista Utilities Electric Operating Statistics
Years Ended December 31,

	2021	2020	2019
Electric Operations (continued)			
Retail Native Load at time of system peak (MW):			
Winter	1,696	1,613	1,577
Summer	1,889	1,721	1,656
Cooling Degree Days: (1)			
Spokane, WA			
Actual	946	546	488
Historical average	546	537	531
% of average	173%	102%	92%
Heating Degree Days: (2)			
Spokane, WA			
Actual	6,124	6,187	6,817
Historical average	6,596	6,651	6,613
% of average	93%	93%	103%

(1) Cooling degree days are the measure of the warmness of weather experienced, based on the extent to which the average of high and low temperatures for a day exceeds 65 degrees Fahrenheit (annual degree days above historical average indicate warmer than average temperatures).

(2) Heating degree days are the measure of the coldness of weather experienced, based on the extent to which the average of high and low temperatures for a day falls below 65 degrees Fahrenheit (annual degree days below historical averages indicate warmer than average temperatures).

Avista Utilities Natural Gas Operating Statistics
Years Ended December 31,

	2021	2020	2019
Natural Gas Operations			
Operating Revenues (Dollars in Thousands):			
Residential	$ 221,405	$ 213,612	$ 196,430
Commercial	100,819	94,937	92,168
Interruptible	4,781	4,285	2,257
Industrial	3,015	2,843	3,006
Total retail	330,020	315,677	293,861
Wholesale	113,277	104,910	135,039
Transportation	8,547	7,917	8,674
Other	7,325	5,034	7,375
Alternative revenue programs	12,890	547	915
Deferrals and amortizations for rate refunds to customers	1,254	1,797	1,368
Total natural gas operating revenues	$ 473,313	$ 435,882	$ 447,232
Therms Delivered (Thousands of Therms):			
Residential	219,835	219,988	231,238
Commercial	130,399	127,659	140,578
Interruptible	16,013	14,854	9,138
Industrial	5,402	5,424	6,212
Total retail	371,649	367,925	387,166
Wholesale	356,891	542,372	590,802
Transportation	172,260	180,361	187,514
Interdepartmental and Company use	479	369	421
Total therms delivered	901,279	1,091,027	1,165,903
Number of Retail Customers (Average for Period):			
Residential	332,187	327,125	321,343
Commercial	36,448	36,164	35,804
Interruptible	42	40	45
Industrial	190	225	241
Total natural gas retail customers	368,867	363,554	357,433
Residential Service Averages:			
Annual use per customer (therms)	662	672	720
Revenue per therm (in dollars)	$ 1.01	$ 0.97	$ 0.85
Annual revenue per customer	$ 666.51	$ 653.00	$ 611.28
Heating Degree Days: (1)			
Spokane, WA			
Actual	6,124	6,187	6,817
Historical average	6,596	6,651	6,613
% of average	93%	93%	103%
Medford, OR			
Actual	4,107	4,181	4,439
Historical average	4,254	4,281	4,291
% of average	97%	98%	103%

(1) Heating degree days are the measure of the coldness of weather experienced, based on the extent to which the average of high and low temperatures for a day falls below 65 degrees Fahrenheit (annual degree days below historic indicate warmer than average temperatures).

Alaska Electric Light and Power Company

AEL&P is the primary operating subsidiary of AERC. AEL&P is the sole utility providing electrical energy in Juneau, Alaska. Juneau is a geographically isolated community with no electric interconnections with the transmission facilities of other utilities and no pipeline access to natural gas or other fuels. Juneau's economy is primarily driven by government activities, tourism, commercial fishing, and mining, as well as activities as the commercial hub of southeast Alaska.

AEL&P owns and operates electric generation, transmission and distribution facilities located in Juneau. AEL&P operates five hydroelectric generation facilities with 102.7 MW of hydroelectric generation capacity. AEL&P owns four of these generation facilities (totaling 24.5 MW of capacity) and has a PPA for the entire output of the Snettisham Hydroelectric Project (totaling 78.2 MW of capacity).

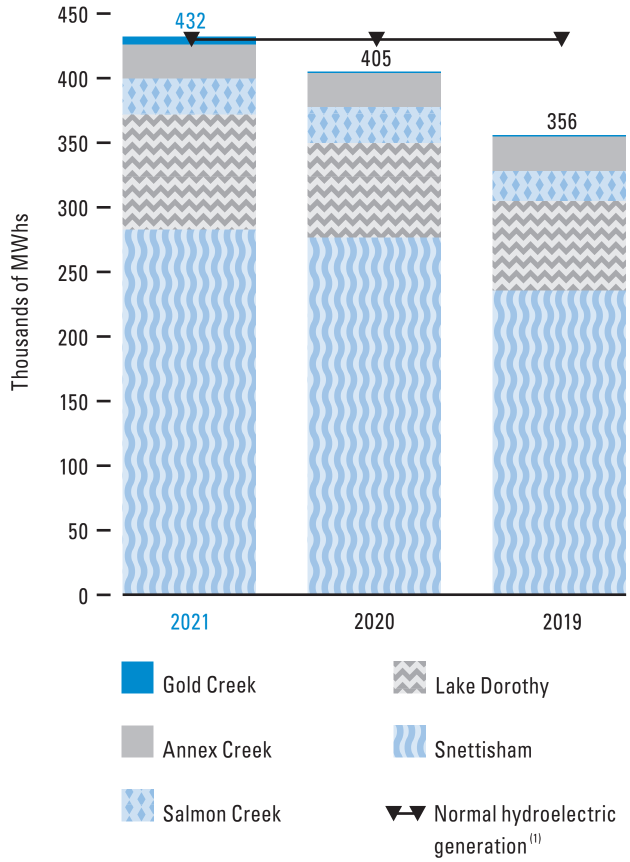
The Snettisham Hydroelectric Project is owned by the Alaska Industrial Development and Export Authority (AIDEA), a public corporation of the State of Alaska. AIDEA issued revenue bonds in 1998 (which were refinanced in 2015) to finance its acquisition of the project. These bonds were outstanding in the amount of $48.8 million at December 31, 2021 and mature in January 2034. AEL&P has a PPA and operating and maintenance agreement with the AIDEA to operate and maintain the facility. This PPA is a take-or-pay obligation, expiring in December 2038, to purchase all of the output of the project. AIDEA's bonds are payable solely out of the revenues received under the PPA. Amounts payable by AEL&P under the PPA are equal to the required debt service on the bonds plus operating and maintenance costs.

This PPA is a finance lease and, as of December 31, 2021, the finance lease obligation was $48.8 million. Snettisham Electric Company, a non-operating subsidiary of AERC, has the option to purchase the Snettisham project at any time for a price equal to the principal amount of the bonds outstanding at that time. See "Note 5 of the Notes to Consolidated Financial Statements" for further discussion of the Snettisham finance lease obligation.

AEL&P also has 107.5 MW of diesel generating capacity from four facilities to provide back-up service to firm customers when necessary.

The following graph shows AEL&P's hydroelectric generation (in thousands of MWhs) during the time periods indicated below:

HYDROELECTRIC GENERATION



(1) *Normal hydroelectric generation is defined as the energy output of the plant during a year with average inflows to the reservoir.*

As of December 31, 2021, AEL&P served approximately 17,400 customers. Its primary customers include city, state and federal governmental entities located in Juneau, as well as a mine located in the Juneau area. Most of AEL&P's customers are served on a firm basis while certain of its customers, including its largest customer, are served on an interruptible sales basis. AEL&P maintains separate rate tariffs for each of its customer classes, as well as seasonal rates.

AEL&P's operations are subject to regulation by the RCA with respect to rates, standard of service, facilities, accounting and certain other matters, but not with respect to the issuance of securities. Rate adjustments for AEL&P's customers require approval by the RCA pursuant to RCA regulations.

AEL&P is also subject to the jurisdiction of the FERC with respect to permits and licenses necessary to operate certain of its hydroelectric facilities. One of these licenses (for the Lake Dorothy hydroelectric project) expires in 2053 while the other (for the Salmon Creek and Annex Creek hydroelectric projects) expires in 2058. Since AEL&P has no electric interconnection with other utilities and makes no wholesale sales, it is not subject to general FERC jurisdiction, other than the reporting and other requirements of the Public Utility Holding Company Act of 2005 as an Avista Corp. subsidiary.

The Snettisham Hydroelectric Project is subject to regulation by the State of Alaska with respect to dam safety and certain aspects of its operations. In addition, AEL&P is subject to regulation with respect to air and water quality, land use and other environmental matters under both federal and state laws.

AEL&P Electric Operating Statistics

Years Ended December 31,

	2021	2020	2019
Electric Operations			
Operating Revenues (Dollars in Thousands):			
Residential	$ 18,940	$ 18,618	$ 17,134
Commercial and government	25,861	23,754	19,391
Public street and highway lighting	250	251	254
Total retail	45,051	42,623	36,779
Other	315	186	486
Total electric operating revenues	$ 45,366	$ 42,809	$ 37,265
Energy Sales (Thousands of MWhs):			
Residential	160	157	143
Commercial and government	243	227	193
Public street and highway lighting	1	1	1
Total electric energy sales	404	385	337
Number of Retail Customers (Average for Period):			
Residential	14,919	14,840	14,755
Commercial and government	2,282	2,271	2,280
Public street and highway lighting	230	228	228
Total electric retail customers	17,431	17,339	17,263
Residential Service Averages:			
Annual use per customer (KWh)	10,773	10,581	9,692
Revenue per KWh (in cents)	11.84	11.86	11.98
Annual revenue per customer	$ 1,269.52	$ 1,254.58	$ 1,161.23
Heating Degree Days: (1)			
Juneau, AK			
Actual	8,394	8,119	7,476
Historical average	8,335	8,351	8,041
% of average	101%	97%	93%

(1) Heating degree days are the measure of the coldness of weather experienced, based on the extent to which the average of high and low temperatures for a day falls below 65 degrees Fahrenheit (annual heating degree days below historical average indicate warmer than average temperatures).

Other Businesses

The following table shows our assets related to our other businesses, including intercompany amounts as of December 31, 2021 and 2020 (dollars in thousands):

Entity and Asset Type	2021	2020
Avista Capital		
Unconsolidated equity investments	$ 91,057	$ 59,318
Note receivable—parent	1,404	8,743
Real estate investments	7,895	11,252
Notes receivable—third parties	17,474	18,065
Other assets	4,294	2,477
Alaska companies (AERC and AJT Mining)	10,034	9,803
Total	$ 132,158	$ 109,658

Avista Capital

- Unconsolidated equity investments are primarily in emerging technology venture capital funds and companies, including an investment in a joint venture focused on local real estate development and economic growth.
- Avista Edge is a wholly owned, unregulated, non-utility subsidiary of Avista Capital whose services initially support public electric utilities with advanced broadband networks and patented technology located at the electric meter, allowing their customers access to high-speed internet services.
- Real estate consists of mixed use commercial, retail office space and land.
- Other assets that consist of income tax receivables, machinery and equipment, cash and other deferred charges.

Alaska Companies

- Includes AERC and AJT Mining, which is a wholly owned subsidiary of AERC and is an inactive mining company holding certain real estate.

Item 1A. Risk Factors

Risk Factors

The following factors could have a significant impact on our operations, results of operations, financial condition or cash flows. These factors could cause future results or outcomes to differ materially from those discussed in our reports filed with the SEC (including this Annual Report on Form 10-K), and elsewhere. Please also see "Forward-Looking Statements" for additional factors which could have a significant impact on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in such statements.

Utility Regulatory Risk Factors

Regulators may not grant rates that provide timely or sufficient recovery of our costs or allow a reasonable rate of return for our shareholders.

Avista Utilities' annual operating expenses and the costs associated with incremental investments in utility assets continue to grow at a faster rate than revenue. Our ability to recover these expenses and capital costs depends on the adequacy and timeliness of retail rate increases allowed by regulatory agencies, as well as managing inflationary pressures. We expect to periodically file for rate increases with regulatory agencies to recover our expenses and capital costs and provide an opportunity to earn a reasonable rate of return for shareholders. If regulators do not grant rate increases or grant substantially lower rate increases than our requests in the future or if recovery of deferred expenses is disallowed, it could have a negative effect on our financial condition, results of operations or cash flows. See further discussion of regulatory matters in "Item 7. Management's Discussion and Analysis—Regulatory Matters."

In the future, we may no longer meet the criteria for continued application of regulatory accounting principles for all or a portion of our regulated operations.

If we could no longer apply regulatory accounting principles, we could be:

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

See further discussion at "Note 1 of the Notes to Consolidated Financial Statements—Regulatory Deferred Charges and Credits."

Operational Risk Factors

Wildfires ignited, or allegedly ignited, by Avista Corp. equipment or facilities, could cause significant loss of life and property, thereby causing serious operational and financial harm.

Our equipment may be the ignition source, or alleged cause of ignition, for wildfires and in the event of a fire caused by our equipment, we could potentially be held liable for resulting damages to life and property, as well as fire suppression costs. Also, wildfires could lead to extended operational outages of our equipment while we wait for the wildfire to be extinguished before restoring power, and the cost to implement rapid response or any repair to such facilities could be significant. Any wildfires caused by our equipment could cause significant damage to our reputation, which could erode shareholder, customer and community satisfaction with our Company. In addition, wildfires caused by our equipment could lead to increased insurance costs, loss of insurance coverage, the need to be self-insured or the need to consider non-traditional insurance coverage or other risk mitigation procedures. Wildfire risks may be exacerbated by increasing temperatures and/or decreasing precipitation due to climate change experienced in the region.

The COVID-19 pandemic is disrupting our business and could have a negative effect on our results of operations, financial condition and cash flows.

The COVID-19 pandemic is currently impacting our business, as well as the global, national and local economy. We cannot predict the full extent to which COVID-19 will impact our operations, results of operations, cash flows, financial condition or capital resources. It is possible that the continued spread of COVID-19 and efforts to contain the virus may result in significant disruptions in various public, commercial or industrial activities, interruption to various supply chains upon which our operations depend, and cause employee absences which could interfere with operation and maintenance of the Company's facilities. Any of these circumstances could adversely affect our operations, results of operations, financial condition and cash flows in many ways, including, but not limited to:

- an increase in operating expenses, including bad debt expense due to our customers' inability to pay amounts due to us,
- an increase in operating expenses and potential workforce disruption or losses resulting from compliance with state or federal vaccine mandates,
- increased costs and/or reduced revenue associated with interruptions in operations due to federal and state vaccine mandates, including but not limited to employee strikes, protests, retirements or resignations, and additional costs associated with ensuring business continuity,
- a decrease in net operating cash inflows, which could negatively impact our liquidity and limit our ability to fund capital expenditures, dividends, and other contractual commitments,
- a negative impact on the ability of suppliers, vendors or contractors to perform, which could increase costs and delay capital projects,
- possible reluctance on the part of regulatory commissions to approve our requests to defer and recover increased expenses,
- delays in regulatory filings and the regulatory approval process, which could impact our ability to timely recover our operating expenses and costs associated with investments in utility assets,
- an increase in cyber and technology risks, including the impact on internal controls, due to a significant number of employees working remotely,
- disruption, weakness and volatility in the financial markets, which could increase our costs to fund capital requirements, and
- possible limited access to the capital markets, that could require us to seek alternative sources of funding for operations and for working capital, any of which could increase our cost of capital.

We cannot predict the duration and severity of the COVID-19 pandemic. The longer and more severe the business disruptions are, the greater the impact on our operations, results of operations, financial condition and cash flows will be.

We are subject to various operational and event risks.

Our operations are subject to operational and event risks that include:

- severe weather or natural disasters, including, but not limited to, avalanches, wind storms, wildfires, earthquakes, snow and ice storms, and heat waves due to normal weather variations as well as the impacts of climate change which could disrupt energy generation, transmission and distribution, as well as the availability and costs of materials, equipment, supplies, support services and general business operations,
- blackouts or disruptions of interconnected transmission systems (the regional power grid),
- unplanned outages at generating plants,
- changes in the availability and cost of purchased power, fuel and natural gas, including delivery constraints,
- explosions, fires, accidents, or mechanical breakdowns that could occur while operating and maintaining our generation, transmission and distribution systems,
- property damage or injuries to third parties caused by our generation, transmission and distribution systems,
- natural disasters that can disrupt energy generation, transmission and distribution, and general business operations,
- terrorist attacks or other malicious acts that may disrupt or cause damage to our utility assets or the vendors we utilize, and
- general workforce problems, including decreased employee engagement, which may impact strategy execution and negatively affect retention, ability to attract workers, and result in challenges in collective bargaining, possible work stoppages, and strikes. Retention of employees may also be negatively impacted by early retirements, insufficient remote work opportunities, and higher pay offered by national employers. Attractions of employees to support strategies may be affected by higher pay offered from other companies, more liberal remote work opportunities offered by other employers, and other work-life balance benefits afforded by other companies.

Disasters could affect the general economy, financial and capital markets, specific industries or our ability to conduct business. As protection against operational and event risks, we maintain business continuity and disaster recovery plans, maintain insurance coverage against some, but not all, potential losses and we seek to negotiate indemnification arrangements with contractors for certain event risks. However, insurance or indemnification agreements may not be adequate to protect us against liability, extra expenses and operating disruptions from all of the operational and event risks described above. In addition, we are subject to the risk that insurers and/or other parties will dispute or be unable to perform on their obligations to us. If insurance or indemnification agreements are unable to adequately protect us or reimburse us for out-of-pocket costs, it could have a material adverse effect on our results of operations, financial condition and cash flows.

Damage to facilities could be caused by severe weather or natural disasters, such as snow, ice, wind storms, wildfires, earthquakes or avalanches. The cost to implement rapid response or any repair to such facilities can be significant. Overhead electric lines are most susceptible to damage caused by severe weather and are not covered by insurance.

Adverse impacts to AEL&P could result from an extended outage of its hydroelectric generating resources or its inability to deliver energy, due to its lack of interconnectivity to any other electrical grids and the cost of replacement power (diesel).

AEL&P operates several hydroelectric power generation facilities and has diesel generating capacity from multiple facilities to provide backup service to firm customers when necessary; however, a single hydroelectric power generation facility, the Snettisham Hydroelectric Project, provides approximately two-thirds of AEL&P's hydroelectric power generation. Any issues that negatively affect AEL&P's ability to generate or transmit power or any decrease in the demand for the power generated by AEL&P could negatively affect our results of operations, financial condition and cash flows.

Climate Change Risk Factors

A trend of increasing average temperatures and its effects could cause significant direct and indirect impacts on Avista's operations and results of operations.

Climate change may exacerbate existing risks related to weather and weather-related events. Potential direct effects of climate change include changes in the timing and magnitude of snowpack and streamflow, impacting hydro generation; timing and magnitude of changes in electric and gas load; increased weather-related stress on, or damage to, energy infrastructure; increased frequency and intensity of extreme weather events that may impact energy generation and delivery.

Indirect impacts associated with climate change may include increased costs to generate electricity or secure natural gas and deliver energy to customers; impacts to the timing or amount of operating revenues; increased costs to maintain or construct energy infrastructure in adaptation to a changing climate; increased costs or inability to obtain insurance coverage; and regional impacts to the economy or financial conditions of our customers. Indirect impacts also include risks associated with new and emerging laws and regulations, which could have a material adverse impact on our business and results of operations. See further discussion at "Item 7. Management's Discussion and Analysis—Environmental Issues and Contingencies."

Cyber and Technology Risk Factors

Cyberattacks, ransomware, terrorism or other malicious acts could disrupt our businesses and have a negative impact on our results of operations and cash flows.

In the course of our operations, we rely on interconnected technology systems for operation of our generating plants, electric transmission and distribution systems, natural gas distribution systems, customer billing and customer service, accounting and other administrative processes and compliance with various regulations. In addition, in the ordinary course of business, we collect and retain sensitive information including personal information about our customers and employees.

Cyberattacks, ransomware, terrorism or other malicious acts could damage, destroy or disrupt these systems for an extended period of time. The energy sector, particularly electric and natural gas utility companies have become the subject of cyberattacks with increased frequency. Our administrative and operating networks are targeted by hackers on a regular basis. Additionally, the facilities and systems of clients, suppliers and third party service providers could be vulnerable to the same cyber or terrorism risks as our facilities and systems and such third party systems may be interconnected to our systems both physically and technologically. Therefore, an event caused by cyberattacks, ransomware or other malicious act at an interconnected third party could impact our business and facilities similarly. Any failure, unexpected, or unauthorized use of technology systems could result in the unavailability of such systems, and could result in a loss of operating revenues, an increase in operating expenses and costs to repair or replace damaged assets. Any of the above could also result in the loss or release of confidential customer and/or employee information or other proprietary data that could adversely affect our reputation and competitiveness, could result in costly litigation and negatively impact our results of operations. These cyberattacks have become more common and sophisticated and, as such, we could be required to incur costs to strengthen our systems and respond to emerging concerns.

Terrorist attacks could also be directed at our physical electric and natural gas facilities, as well as technology systems or at an interconnected third party, which could result in disruption to our systems.

There are various risks associated with technology systems such as hardware or software failure, communications failure, data distortion or destruction, unauthorized access to data, misuse of proprietary or confidential data, unauthorized control through electronic means, programming mistakes and other deliberate or inadvertent human errors.

Our technology may become obsolete or we may not have sufficient resources to manage our technology.

Our technology may become obsolete before the end of its useful life. In addition, custom technology that is heavily relied upon by us may not be maintained and updated appropriately due to resource restraints, or other factors, which could cause technology failures or give rise to additional operational or security risks. Technology failures could result in significant adverse effects on our operations, results of operations, financial condition and cash flows.

We may be adversely affected by our inability to successfully implement certain technology projects.

There are inherent risks associated with replacing and changing systems, which could have a material adverse effect on our results of operations, financial condition and cash flows. Finally, there is the risk that we ultimately do not complete a project and will incur contract cancellation or other costs, which could be significant.

Strategic Risk Factors

Our strategic business plans, which may be affected by any or all of the foregoing, may change, including the entry into new businesses and/or the exit from existing businesses and/or the curtailment of our business development efforts where potential future business is uncertain.

Our strategic business plans could be affected by or result in any of the following:

- disruptive innovations in the marketplace may outpace our ability to compete or manage our risk,
- customers may have a choice in the future over the sources from which to receive their energy and we may not be able to compete,
- potential difficulties in integrating acquired operations and in realizing expected opportunities, diversions of management resources and losses of key employees, challenges with respect to operating new businesses and other unanticipated risks and liabilities,
- non-regulated investments may increase earnings volatility,
- market or other conditions that could adversely affect our operations or require changes to our business strategy and could result in reduced assets and net income,
- potential reputational risk arising from repeated general rate case filings, degradation in the quality of service, or from failed strategic investments and opportunities, which could erode shareholder, customer and community satisfaction with the Company, and
- the risk of municipalization or other form of service territory reduction.

External Mandates Risk Factors

External mandate risk involves forces outside the Company, which may include significant changes in customer expectations, disruptive technologies that result in obsolescence of our business model and government action that could impact the Company.

Actions or limitations to address concerns over long-term climate change, both globally and within our utilities' service areas, may affect our operations and financial performance.

Legislative, regulatory and advocacy efforts at the local, state, national and international levels concerning climate change and other environmental issues could have significant impacts on our operations. The electric and natural gas utility industries are frequently affected by proposals to curb greenhouse gas and other air emissions. Various regulatory and legislative proposals have been made to limit or further restrict byproducts of combustion, including that resulting from the use of natural gas by our customers. In addition, regionally, there are a number of regulatory and legislative initiatives that have been passed which are designed to limit greenhouse gas emissions and increase the use of renewable sources of energy. Such legislation could restrict the operation and raise the costs of our power generation resources as well as the distribution of natural gas to our customers.

We expect continuing activity in the future and we are evaluating the extent to which potential changes to environmental laws and regulations may:

- increase the operating costs of generating plants,
- increase the lead time and capital costs for the construction of new generating plants,
- require modification of our existing generating plants,
- require existing generating plant operations to be curtailed or shut down,
- reduce the amount of energy available from our generating plants,
- restrict the types of generating plants that can be built or contracted with,
- require construction of specific types of generation plants at higher cost, and
- increase the cost or limit our ability to distribute natural gas to customers.

See "Item 7. Management's Discussion and Analysis—Environmental Issues and Contingencies" for discussion regarding environmental and other issues which may affect our operations, including legislation that was recently passed in Washington State.

We have contingent liabilities, including certain matters related to potential environmental liabilities, and cannot predict the outcome of these matters.

In the normal course of our business, we have matters that are the subject of ongoing litigation, mediation, investigation and/or negotiation. We cannot predict the ultimate outcome or potential impact of any particular issue, including the extent, if any, of insurance coverage or that amounts payable by us may be recoverable through the ratemaking process. We are subject to environmental regulation by federal, state and local authorities related to our past, present and future operations. See "Note 22 of the Notes to Consolidated Financial Statements" for further details of these matters.

Import tariffs could lead to increased prices on raw materials that are critical to our business.

Tariffs and other restrictions on trade with foreign countries could significantly increase the prices of raw materials that are critical to our business, such as steel poles or wires. In addition, tariffs and trade restrictions could have a similar impact on our suppliers and certain customers, which could have a negative impact on our financial condition, results of operations and cash flows.

See "Item 7. Management's Discussion and Analysis—Environmental Issues and Contingencies" and "Forward-Looking Statements" for discussion of or reference to additional external mandates which could have a material adverse effect on our results of operations, financial condition and cash flows.

Financial Risk Factors

Weather (temperatures, precipitation levels, wind patterns and storms) has a significant effect on our results of operations, financial condition and cash flows. These effects could increase as climate changes occur.

Weather impacts are described in the following subtopics:

- certain retail electricity and natural gas sales,
- the cost of natural gas supply, and
- the cost of power supply.

Certain retail electricity and natural gas sales volumes vary directly with changes in temperatures. We normally have our highest retail (electric and natural gas) energy sales during the winter heating season in the first and fourth quarters of the year. We also have high electricity demand for air conditioning during the summer (third quarter). In general, warmer weather in the heating season and cooler weather in the cooling season will reduce our customers' energy demand and our retail operating revenues. The revenue and earnings impact of weather fluctuations is somewhat mitigated by our decoupling mechanisms; however, we could experience liquidity constraints during the period between when decoupling revenue is earned and when it is subsequently collected from customers through retail rates.

The cost of natural gas supply is impacted by both supply-side factors (amount of natural gas production, level of natural gas in storage, volumes of natural gas imports and exports, regulatory restraints or costs on natural gas production and delivery) and demand-side factors (variations in winter and summer weather, level of economic growth, availability and prices of other fuels). Prices tend to increase with higher demand during periods of cold weather. Inter-regional natural gas pipelines and competition for supply can allow demand-driven price volatility in other regions of North America to affect prices in the Pacific Northwest. Increased costs adversely affect cash flows when we purchase natural gas for retail supply at prices above the amount allowed for recovery in retail rates. We defer differences between actual natural gas supply costs and the amount currently recovered in retail rates and we are generally allowed to recover substantially all of these differences after regulatory review. However, these deferred costs require cash outflows from the time of natural gas purchases until the costs are later recovered through retail sales.

The cost of power supply can be significantly affected by weather, and therefore is subject to trends in climate change. Precipitation (consisting of snowpack, its water content and runoff pattern plus rainfall) and other streamflow conditions (such as regional water storage operations) significantly affect hydroelectric generation capability. Variations in hydroelectric generation inversely affect our reliance on market purchases and thermal generation. To the extent that hydroelectric generation is less than normal, significantly more costly power supply resources must be acquired and the ability to realize net benefits from surplus hydroelectric wholesale sales is reduced. Wholesale prices also vary based on wind patterns as wind generation capacity is material in the Pacific Northwest but its contribution to supply is inconsistent.

The price of power in the wholesale energy markets tends to be higher during periods of high regional demand, such as occurs with temperature extremes. Climate change may increase the frequency and magnitude of temperature extremes. We may need to purchase power in the wholesale market during peak price periods. The price of natural gas as fuel for natural gas-fired electric generation also tends to increase during periods of high demand which are often related to temperature extremes. We may need to purchase natural gas fuel in these periods of high prices to meet electric demands. The cost of power supply during peak usage periods may be higher than the retail sales price or the amount allowed in retail rates by our regulators. To the extent that power supply costs are above the amount allowed currently in retail rates, the difference is partially absorbed by the Company in current expense and is partially deferred or shared with customers through regulatory mechanisms.

The price of power tends to be lower during periods with excess supply, such as the spring when hydroelectric conditions are usually at their maximum and various facilities are required to operate to meet environmental mandates. Oversupply can be exacerbated when intermittent resources such as wind generation are producing output that may be supported by price subsidies. In extreme situations, we may be required to sell excess energy at negative prices.

As a result of these combined factors, our net cost of power supply—the difference between our costs of generation and market purchases, reduced by our revenue from wholesale sales—varies significantly because of weather.

We rely on regular access to financial markets but we cannot assure favorable or reasonable financing terms will be available when we need them.

Access to capital markets is critical to our operations and our capital structure. We have significant capital requirements that we expect to fund, in part, by accessing capital markets. As such, the state of financial markets and credit availability in the global, United States and regional economies impacts our financial condition. We could experience increased borrowing costs or limited access to capital on reasonable terms.

We access long-term capital markets to finance capital expenditures, repay maturing long-term debt and obtain additional working capital from time-to-time. Our ability to access capital on reasonable terms is subject to numerous factors and market conditions, many of which are beyond our control. If we are unable to obtain capital on reasonable terms, it may limit or prohibit our ability to finance capital expenditures and repay maturing long-term debt. Our liquidity needs could exceed our short-term credit availability and lead to defaults on various financing arrangements. We would also likely be prohibited from paying dividends on our common stock.

Performance of the financial markets could also result in significant declines in the market values of assets held by our pension plan and/or a significant increase in the pension liability (which impacts the funded status of the plan) and could increase future funding obligations and pension expense.

We rely on credit from financial institutions for short-term borrowings. We need adequate levels of credit with financial institutions for short-term liquidity. There is no assurance that we will have access to credit beyond the expiration dates of our committed line of credit agreements. These agreements contain customary covenants and default provisions.

Any default on the lines of credit or other financing arrangements of Avista Corp. or any of our "significant subsidiaries," if any, could result in cross-defaults to other agreements of such entity, and/or to the line of credit or other financing arrangements of any other of such entities. Any defaults could also induce vendors and other counterparties to demand collateral. In the event of any such default, it would be difficult for us to obtain financing on reasonable terms to pay creditors or fund operations. We would also likely be prohibited from paying dividends on our common stock.

We hedge a portion of our interest rate risk with financial derivative instruments. If market interest rates decrease below the interest rates we have locked in, this will result in a liability related to our interest rate swap derivatives, which can be significant. We may be required to post cash or letters of credit as collateral depending on fluctuations in the fair value of the derivative instruments. Settlement of interest rate swap derivative instruments in a liability position could require a significant amount of cash, which could negatively impact our liquidity and short-term credit availability and increase interest expense over the term of the associated debt.

Downgrades in our credit ratings could impede our ability to obtain financing, adversely affect the terms of financing and impact our ability to transact for or hedge energy resources. If we do not maintain our investment grade credit rating with the major credit rating agencies, we could expect increased debt service costs, limitations on our ability to access capital markets or obtain other financing on reasonable terms, and requirements to provide collateral (in the form of cash or letters of credit) to lenders and counterparties. In addition, credit rating downgrades could reduce the number of counterparties willing to do business with us or result in the termination of outstanding regulatory authorizations for certain financing activities.

Credit risk may be affected by industry concentration and geographic concentration.

We have concentrations of suppliers and customers in the electric and natural gas industries including:

- electric and natural gas utilities,
- electric generators and transmission providers,
- oil and natural gas producers and pipelines,
- financial institutions including commodity clearing exchanges and related parties, and
- energy marketing and trading companies.

We have concentrations of credit risk related to our geographic location in the western United States and western Canada energy markets. These concentrations of counterparties and concentrations of geographic location may affect our overall exposure to credit risk because the counterparties may be similarly affected by changes in conditions.

Energy Commodity Risk Factors

Energy commodity price changes affect our cash flows and results of operations.

Energy commodity prices can be volatile. We rely on energy markets and other counterparties for energy supply, surplus and optimization transactions and commodity price hedging. A combination of factors exposes our operations to commodity price risks, including:

- our obligation to serve our retail customers at rates set through the regulatory process—we cannot decline to serve our customers and we cannot change retail rates to reflect current energy prices unless and until we receive regulatory approval,
- customer demand, which is beyond our control because of weather, customer choices, prevailing economic conditions and other factors,
- some of our energy supply cost is fixed by the nature of the energy-producing assets or through contractual arrangements (however, a significant portion of our energy resource costs are not fixed), and
- the potential non-performance by commodity counterparties, which could lead to replacement of the scheduled energy or natural gas at higher prices.

Because we must supply the amount of energy demanded by our customers and we must sell it at fixed rates and only a portion of our energy supply costs are fixed, we are subject to the risk of buying energy at higher prices in wholesale energy markets (and the risk of selling energy at lower prices if we are in a surplus position). Electricity and natural gas in wholesale markets are commodities with historically high price volatility. Changes in wholesale energy prices affect, among other things, the cash requirements to purchase electricity and natural gas for retail customers or wholesale obligations and the market value of derivative assets and liabilities.

When we enter into fixed price energy commodity transactions for future delivery, we are subject to credit terms that may require us to provide collateral to wholesale counterparties related to the difference between current prices and the agreed upon fixed prices. These collateral requirements can place significant demands on our cash flows or borrowing arrangements. Price volatility can cause collateral requirements to change quickly and significantly.

Cash flow deferrals related to energy commodities can be significant. We are permitted to collect from customers only amounts approved by regulatory commissions. However, our costs to provide energy service can be much higher or lower than the amounts currently billed to customers. We are permitted to defer income statement recognition and recovery from customers for some of these differences, which are recorded as deferred charges with the opportunity for future recovery through retail rates. These deferred costs are subject to review for prudence and potential disallowance by regulators, who have discretion as to the extent and timing of future recovery or refund to customers.

Power and natural gas costs higher than those recovered in retail rates negatively impact cash flows. Amounts that are not allowed for deferral or which are not approved to become part of customer rates affect our results of operations.

Even if our regulators ultimately allow us to recover deferred power and natural gas costs, our operating cash flows can be negatively affected until these costs are recovered from customers.

Fluctuating energy commodity prices and volumes in relation to our energy risk management process can cause volatility in our cash flows and results of operations. We engage in active hedging and resource optimization practices to reduce energy cost volatility and economic exposure related to commodity price fluctuations. We routinely enter into contracts to hedge a portion of our purchase and sale commitments for electricity and natural gas, as well as forecasted excess or deficit energy positions and inventories of natural gas. We use physical energy contracts and derivative instruments, such as forwards, futures, swaps and options traded in the over-the-counter markets or on exchanges. If market prices decrease compared to the prices we have locked in with our energy commodity derivatives, this will result in a liability related to these derivatives, which can be significant. As a result of price fluctuations, we may be required to post significant amounts of cash or letters of credit as collateral depending on fluctuations in the fair value of the derivative instruments.

We do not attempt to fully hedge our energy resource assets or our forecasted net positions for various time horizons. To the extent we have positions that are not hedged, or if hedging positions do not fully match the corresponding purchase or sale, fluctuating commodity prices could have a material effect on our operating revenues, resource costs, derivative assets and liabilities, and operating cash flows. In addition, actual loads and resources typically vary from forecasts, sometimes to a significant degree, which require additional transactions or dispatch decisions that impact cash flows.

The hedges we enter into are reviewed for prudence by our various regulators and any deferred costs (including those as a result of our hedging transactions) are subject to review for prudence and potential disallowance by regulators.

Generation plants may become obsolete. We rely on a variety of generation and energy commodity market sources to fulfill our obligation to serve customers and meet the demands of our counterparty agreements. Some of our generation sources, such as coal, may become obsolete or be prematurely retired through regulatory action or legislation. This could result in higher commodity costs to replace the lost generation, as well as higher costs to retire the generation source before the end of its expected life. See "Item 7. Management's Discussion and Analysis—Environmental Issues and Contingencies" for discussion regarding environmental and other issues surrounding Colstrip, including the requirement that we cannot serve Washington electricity customers after 2025 with Colstrip.

Compliance Risk Factors

There have been numerous changes in legislation, related administrative rulemakings, and Executive Orders, including periodic audits of compliance with such rules, which may adversely affect our operational and financial performance.

We expect to continue to be affected by legislation at the national, state and local level, as well as by administrative rules and requirements published by government agencies, including but not limited to the FERC, the EPA and state regulators. We are also subject to NERC and WECC reliability standards. The FERC, the NERC and the WECC perform periodic audits of the Company. Failure to comply with the FERC, the NERC, or the WECC requirements can result in financial penalties.

Future legislation, administrative rules or Executive Orders could have a material adverse effect on our operations, results of operations, financial condition and cash flows.

Item 1B. Unresolved Staff Comments

As of the filing date of this Annual Report on Form 10-K, we have no unresolved comments from the staff of the SEC.

Item 2. Properties

Avista Utilities

Substantially all of Avista Utilities' properties are subject to the lien of Avista Corp.'s mortgage indenture.

Avista Utilities' electric properties, located in the states of Washington, Idaho, Montana and Oregon, include the following:

GENERATION PROPERTIES

	No. of Units	Nameplate Rating (MW) (1)	Present Capability (MW) (2)
Hydroelectric Generating Stations (River)			
Washington:			
Long Lake (Spokane)	4	71.1	88.0
Little Falls (Spokane)	4	43.2	48.0
Nine Mile (Spokane)	4	37.6	40.6
Upper Falls (Spokane)	1	10.0	10.2
Monroe Street (Spokane)	1	14.8	15.0
Idaho:			
Cabinet Gorge (Clark Fork) (3)	4	265.0	273.0
Post Falls (Spokane)	6	14.8	11.9
Montana:			
Noxon Rapids (Clark Fork)	5	487.8	562.4
Total Hydroelectric		944.3	1,049.1
Thermal Generating Stations (cycle, fuel source)			
Washington:			
Kettle Falls GS (combined-cycle, wood waste) (4)	1	50.7	53.5
Kettle Falls CT (combined-cycle, natural gas) (4)	1	7.2	6.9
Northeast CT (simple-cycle, natural gas)	2	61.8	64.8
Boulder Park GS (simple-cycle, natural gas)	6	24.6	24.6
Idaho:			
Rathdrum CT (simple-cycle, natural gas)	2	166.5	166.5
Montana:			
Colstrip Units 3 & 4 (simple-cycle, coal) (5)	2	233.4	222.0
Oregon:			
Coyote Springs 2 (combined-cycle, natural gas)	1	295.0	295.0
Total Thermal		839.2	833.3
Total Generation Properties		1,783.5	1,882.4

(1) Nameplate rating, also referred to as "installed capacity," is the manufacturer's assigned power capability under specified conditions.

(2) Present capability is the maximum capacity of the plant under standard test conditions without exceeding specified limits of temperature, stress and environmental conditions. Information is provided as of December 31, 2021.

(3) For Cabinet Gorge, we have water rights permitting generation up to 265 MW. However, if natural stream flows will allow for generation above our water rights, we are able to generate above our water rights. If natural stream flows only allow for generation at or below 265 MW, we are limited to generation of 265 MW. The present capability disclosed above represents the capability based on maximum stream flow conditions when we are allowed to generate above our water rights.

(4) These generating stations can operate as separate single-cycle plants or combined-cycle with the natural gas plant providing exhaust heat to the wood boiler to increase efficiency.

(5) Jointly owned; data refers to our 15 percent interest. See "Item 7. Management's Discussion and Analysis of Financial Condition—Colstrip" for information related to Colstrip Units 3 & 4.

Electric Distribution and Transmission Plant

Avista Utilities owns and operates approximately 19,300 miles of primary and secondary electric distribution lines providing service to retail customers. We have an electric transmission system of approximately 700 miles of 230 kV line and approximately 1,600 miles of 115 kV line. We also own an 11 percent interest in approximately 500 miles of a 500 kV line between Colstrip, Montana and Townsend, Montana. Our transmission and distribution systems also include numerous substations with transformers, switches, monitoring and metering devices and other equipment.

The 230 kV lines are the backbone of our transmission grid and are used to transmit power from generation resources, including

Noxon Rapids, Cabinet Gorge and the Mid-Columbia hydroelectric projects, to the major load centers in our service area, as well as to transfer power between points of interconnection with adjoining electric transmission systems. These lines interconnect at various locations with the BPA, Grant County PUD, PacifiCorp, NorthWestern Energy and Idaho Power Company and serve as points of delivery for power from generating facilities outside of our service area, including Colstrip, Coyote Springs 2 and the Lancaster Plant.

These lines also provide a means for us to optimize resources by entering into short-term purchases and sales of power with entities within and outside of the Pacific Northwest.

The 115 kV lines provide for transmission of energy and the integration of smaller generation facilities with our service-area load centers, including the Spokane River hydroelectric projects, the Kettle Falls projects, Rathdrum CT, Boulder Park GS and the Northeast CT. These lines interconnect with the BPA, Chelan County PUD, the Grand Coulee Project Hydroelectric Authority, Grant County PUD, NorthWestern Energy, PacifiCorp and Pend Oreille County PUD.

Both the 115 kV and 230 kV interconnections with the BPA are used to transfer energy to facilitate service to each other's customers that are connected through the other's transmission system. We hold a long-term transmission agreement with the BPA that allows us to serve our native load customers that are connected through the BPA's transmission system.

Natural Gas Plant

Avista Utilities has natural gas distribution mains of approximately 3,500 miles in Washington, 2,100 miles in Idaho and 2,400 miles in Oregon. We have natural gas transmission mains of approximately 75 miles in Washington and 15 miles in Oregon. Our natural gas system includes numerous regulator stations, service distribution lines, monitoring and metering devices, and other equipment.

We own a one-third interest in Jackson Prairie, an underground natural gas storage field located near Chehalis, Washington. See "Part 1—Item 1. Business—Avista Utilities—Natural Gas Operations" for further discussion of Jackson Prairie.

Alaska Electric Light and Power Company

Substantially all of AEL&P's utility properties are subject to the lien of the AEL&P mortgage indenture.

AEL&P's utility electric properties, located in Alaska include the following:

GENERATION PROPERTIES AND TRANSMISSION AND DISTRIBUTION LINES

	No. of Units	Nameplate Rating (MW) (1)	Present Capability (MW) (2)
Hydroelectric Generating Stations			
Snettisham (3)	3	78.2	78.2
Lake Dorothy	1	14.3	14.3
Salmon Creek	1	8.4	5.0
Annex Creek	2	4.1	3.6
Gold Creek	3	1.6	1.6
Total Hydroelectric		106.6	102.7
Diesel Generating Stations			
Lemon Creek	11	61.4	51.8
Auke Bay	3	28.4	25.2
Gold Creek	5	8.2	7.0
Industrial Blvd. Plant	1	23.5	23.5
Total Diesel		121.5	107.5
Total Generation Properties		228.1	210.2

(1) Nameplate rating, also referred to as "installed capacity," is the manufacturer's assigned power capability under specified conditions.

(2) Present capability is the maximum capacity of the plant under standard test conditions without exceeding specified limits of temperature, stress and environmental conditions. Information is provided as of December 31, 2021.

(3) AEL&P does not own this generating facility but has a PPA under which it has the right to purchase, and the obligation to pay for (whether or not energy is received), all of the capacity and energy of this facility. See further information at "Part 1. Item 1. Business—Alaska Electric Light and Power Company."

In addition to the generation properties above, AEL&P owns 61 miles of transmission lines, which are primarily comprised of 69 kV line, and 184 miles of distribution lines.

Item 3. Legal Proceedings

See "Note 22 of Notes to Consolidated Financial Statements" for information with respect to legal proceedings.

Item 4. Mine Safety Disclosures

Not applicable.

Part II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Avista Corp. Market Information and Dividend Policy

Avista Corp.'s common stock is listed on the New York Stock Exchange under the ticker symbol "AVA." As of January 31, 2022, there were 6,574 registered shareholders of our common stock.

Avista Corp.'s Board of Directors considers the level of dividends on our common stock on a recurring basis, taking into account numerous factors including, without limitation:

- our results of operations, cash flows and financial condition,
- the success of our business strategies, and
- general economic and competitive conditions.

Avista Corp.'s net income available for dividends is generally derived from our regulated utility operations (Avista Utilities and AEL&P).

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 (see "Item 7. Management's Discussion and Analysis—Capital Resources" for compliance with these covenants),
- the hydroelectric licensing requirements of section 10(d) of the FPA (see "Note 1 of Notes to Consolidated Financial Statements"), and
- certain requirements under the OPUC approval of the AERC acquisition in 2014. The OPUC's AERC acquisition order requires Avista Utilities to maintain a capital structure of no less than 35 percent common equity (inclusive of short-term debt). This limitation may be revised upon request by the Company with approval from the OPUC.

For additional information, see "Notes 1 and 19 of Notes to Consolidated Financial Statements."

For information with respect to securities authorized for issuance under equity compensation plans, see "Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters."

Item 6. [Removed and Reserved]

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

This section of this Annual Report on Form 10-K generally discusses 2021 and 2020 financial statement items and year-to-year comparisons between 2021 and 2020. Discussion of 2019 financial statement items and year-to-year comparisons between 2020 and 2019 that are not included in this Form 10-K can be found in "Management's Discussion and Analysis of Financial Conditions and Results of Operations" in Part II, Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2020.

Business Segments

As of December 31, 2021, we have two reportable business segments, Avista Utilities and AEL&P. We also have other businesses which do not represent a reportable business segment and are conducted by various direct and indirect subsidiaries of Avista Corp. See "Part I, Item 1. Business—Company Overview" for further discussion of our business segments.

The following table presents net income (loss) attributable to Avista Corp. shareholders for each of our business segments (and the other businesses) for the year ended December 31 (dollars in thousands):

	2021	2020	2019
Avista Utilities	$ 125,558	$ 124,810	$ 183,977
AEL&P	7,224	8,095	7,458
Other	14,552	(3,417)	5,544
Net income attributable to Avista Corporation shareholders	$ 147,334	$ 129,488	$ 196,979

Executive Level Summary

Overall Results

Net income attributable to Avista Corp. shareholders was $147.3 million for 2021, an increase from $129.5 million for 2020.

Avista Utilities' net income increased primarily due to general rate cases, including the impact of the timing of recognition of income taxes, and non-decoupled revenue growth and customer growth. These increases were partially offset by higher power supply costs, increased other operating expenses, and increased depreciation due to plant additions during the year. In addition, 2020 included an accrual for customer refunds related to the outcome of our 2015 Washington General rate case, an accrual for disallowed replacement power during an unplanned outage at Colstrip and a contribution to the Colstrip community fund, all of which decreased net income in 2020.

AEL&P net income decreased slightly, primarily due to higher other operating costs compared to 2020.

The increase in net income at our other businesses was primarily due to increased net investment gains in 2021.

More detailed explanations of the fluctuations are provided in the results of operations and business segment discussions (Avista Utilities, AEL&P, and the other businesses).

Summer Weather Conditions

The Pacific Northwest experienced hot and dry weather conditions throughout the second and third quarters of 2021 compared to normal weather conditions for these times of year. These weather conditions resulted in higher than usual customer loads, as well as lower than usual hydroelectric generation. In these periods, we often have excess generation to sell into the wholesale markets, which benefits our net power supply costs. This did not occur at expected levels in 2021 primarily due to the hot and dry weather conditions throughout the Pacific Northwest.

As a result of our lower than normal hydroelectric generation capability and in order to serve higher than usual loads, we were required to rely more heavily than usual on purchased power and our thermal generation, which in turn resulted in higher than authorized resource costs due to higher volumes of energy and fuel purchased and higher market prices of each. In 2021, we recognized a pre-tax expense of $7.7 million under the ERM, compared to $6.2 million of pre-tax benefit recognized in 2020.

These hot conditions had minimal impact on reported revenues, as the majority of the increase in revenues associated with the increased usage was offset with adjustments under the decoupling mechanisms that cover a majority of our customers.

COVID-19 Pandemic

The COVID-19 pandemic is impacting our business, as well as the global, national and local economies. However, through 2021 the economies in our service territory have opened, and the impacts of the pandemic have been less severe than 2020. The pandemic has affected and may continue to affect our operations, results of operations, financial condition, liquidity and cash flows in the following ways:

Operations

We continue to experience supply chain delays due to the effects of the COVID-19 pandemic that have impacted the delivery times of some of our materials and equipment. The delays are being managed with minimal impact. The issues that could potentially result from future delays are being proactively mitigated through several planning and review activities, but could have an impact on our planned projects going forward.

It is possible that COVID-19 could have a negative impact on the ability of suppliers or contractors to perform, which could increase operating costs and delay and/or increase the costs of capital projects.

Results of Operations

We observed economic recovery and improvement in employment during 2021. We received accounting orders in each of our jurisdictions to defer the recognition of COVID-19 expenses as well as identified cost savings of other COVID-19 related benefits.

COVID-19 deferred regulatory assets and liabilities as of December 31, 2021 and December 31, 2020 were as follows:

	2021	2020
Regulatory asset	$ 13,591	$ 8,166
Regulatory liability	(12,500)	(10,949)
Total	$ 1,091	$ (2,783)

Financial Condition, Liquidity and Cash Flows

After considering the impacts of COVID-19, and the planned issuances of long-term debt and equity during 2022, we expect net cash flows from operations, together with cash available under our committed lines of credit, to provide adequate resources to fund capital expenditures, dividends and other contractual commitments.

We cannot predict the duration and severity of the COVID-19 pandemic or if emerging variants will result in the reimplementation of economic restrictions. The longer and more severe the economic restrictions and business disruption, the greater the impact on our operations, results of operations, financial condition and cash flows.

General Rate Cases and Regulatory Lag

We experienced regulatory lag during 2021 and we expect this to continue through the end of 2022 due to our continued investment in utility infrastructure. In 2021, we concluded general rates cases in each of our jurisdictions. The settlement of these cases provided rate relief in 2021. Going forward, we will continue to strive to reduce the regulatory timing lag and more closely align our earned returns with those authorized by 2023. This will require adequate and timely rate relief in all our jurisdictions. We have filed multi-year electric and natural gas general rate cases in Washington in January 2022. See "Regulatory Matters" for additional discussion of the general rate cases.

Regulatory Matters

General Rate Cases

We regularly review the need for electric and natural gas rate changes in each state in which we provide service. We will continue to file for rate adjustments to:

- seek recovery of operating costs and capital investments, and
- seek the opportunity to earn reasonable returns as allowed by regulators.

With regards to the timing and plans for future filings, the assessment of our need for rate relief and the development of rate case plans takes into consideration short-term and long-term needs, as well as specific factors that can affect the timing of rate filings. Such factors include, but are not limited to, in-service dates of major capital investments and the timing of changes in major revenue and expense items.

Avista Utilities

Washington General Rate Cases and Other Proceedings

2019 General Rate Cases

In March 2020, we received an order from the WUTC that approved a partial multi-party settlement. The approved rates were designed to increase annual base electric revenues by $28.5 million, or

5.7 percent, and annual natural gas base revenues by $8.0 million, or 8.5 percent, effective April 1, 2020. The revenue increases incorporate a 9.4 percent return on equity (ROE) with a common equity ratio of 48.5 percent and a rate of return (ROR) on rate base of 7.21 percent.

As part of the WUTC order, we are returning approximately $40 million from the ERM rebate to customers over a two-year period.

Included in the WUTC order is the acceleration of depreciation of Colstrip Units 3 & 4 to reflect a remaining useful life through December 31, 2025. The order utilized certain electric tax benefits associated with the 2018 tax reform to partially offset these increased costs. The order also set aside $3 million for community transition efforts to mitigate the impacts of the eventual closure of Colstrip, half funded by customers and half funded by our shareholders. See "Colstrip" section for further information on on-going issues and disputes regarding the eventual closure of Colstrip.

Lastly, the order included the extension of electric and natural gas decoupling mechanisms through March 31, 2025, with one modification in that new customers added after any test period will not be decoupled until included in a future test period.

2020 General Rate Cases

In September 2021, we received an order from the WUTC that approved a partial multi-party settlement and resolved all remaining issues for the electric and natural gas general rate cases with the WUTC. The approved rates are designed to increase annual base electric revenues by $13.6 million, or 2.6 percent, and annual natural gas base revenues by $8.1 million, or 7.7 percent, effective October 1, 2021. The revenue increases incorporate a 9.4 percent ROE with a common equity ratio of 48.5 percent and a ROR of 7.12 percent.

While base rates increased, there was no increase in billed rates at this time because of the use of offsetting tax benefits.

The WUTC's order approved recovery of capital additions including investments in advanced metering infrastructure, wildfire resiliency, joining the Western Energy Imbalance Market, and other projects. The WUTC disallowed $2.5 million of costs associated with Colstrip SmartBurn technology.

The WUTC order also approves the Company's request to defer incremental wildfire expenses incurred during 2021, as well as the Company's use of a wildfire balancing account to track the level of expense associated with wildfire resiliency going forward.

2022 General Rate Cases

In January 2022, we filed multi-year electric and natural gas general rate cases with the WUTC. The proposed rates are designed to increase annual base electric revenues by $52.9 million (or 9.6 percent of base revenues), effective in December 2022, and $17.1 million (or 2.8 percent of base revenues), effective in December 2023. For natural gas, the proposed rates are designed to increase annual base natural gas revenues by $10.9 million (or 9.5 percent of base revenues), effective in December 2022, and $2.2 million (or 1.7 percent of base revenues), effective in December 2023.

We are proposing to offset part of the base rate request with a Residual Tax Customer Credit that arose out of the Company's Washington electric and natural gas general rate cases that went into effect on October 1, 2021. The order for those general rate cases stipulated that the residual tax customer credit was to be flowed through to customers over a 10-year period beginning in 2023; however, we are now proposing that this credit be incrementally flowed through to customers over a two-year period. The estimated benefits to customers of this credit would be $25.5 million for electric customers and $12.5 million for natural gas customers over a two-year period from December 2022 to December 2024.

The proposed electric and natural gas revenue increase requests are based on a 10.25 percent ROE with a common equity ratio of 48.5 percent and a rate of ROR base of 7.3 percent. Increasing fixed expenses and ongoing capital investments (including replacement of wood poles and natural gas distribution pipe, continued investment in the wildfire resiliency plan, and technology) were the main drivers of proposed increases. As a part of the multi-year rate plan, if approved, we would not file a new general rate case for a new rate plan to be effective prior to December 2024. The WUTC has up to eleven months to review the general rate case filings and issue a decision.

Washington Engrossed Substitute Senate Bill 5295

This bill, which was signed into law and is effective as of July 25, 2021, is designed to promote multi-year rate plans and performance-based rate making for electric and natural gas utilities. The bill includes a number of provisions such as required multi-year rate plans from 2–4 years in length, methodologies the WUTC may use to minimize regulatory lag and/or adjust for under earning and starts an investigation into Performance Based Ratemaking Metrics, an initial move that may help to modify the historical test-year ratemaking construct. On October 20, 2021, the WUTC issued a notice of opportunity to comment on a proposed work plan to be conducted in various phases between 2021 and 2025, initially focusing on Performance Based Ratemaking and identifying performance metrics. Thereafter, the WUTC will address revenue adjustment mechanisms and performance incentives in the context of multi-year rate plans. The new law leaves much to the discretion of the WUTC, and we cannot predict the extent to which the WUTC will embrace the options now permitted.

Idaho General Rate Cases and Other Proceedings

2021 General Rate Cases

In January 2021, we filed electric and natural gas general rate cases with the IPUC.

In September 2021, the IPUC approved the all party settlement agreement. The approved rates under the settlement agreement are designed to increase annual base electric revenues by $10.6 million, or 4.3 percent, effective September 1, 2021, and $8.0 million, or 3.1 percent, effective September 1, 2022. For natural gas, the proposed rates under the settlement agreement are designed to decrease annual base natural gas revenues by $1.6 million, or 3.7 percent, effective September 1, 2021, and increase annual base revenues by $0.9 million, or 2.2 percent, effective September 1, 2022. The parties have agreed to use the tax customer credits, related to flow through of certain tax items, included in our original filing to offset overall proposed changes to electric and natural gas rates over the two-year plan.

The settlement incorporates 9.4 percent ROE with a common equity ratio of 50 percent and a ROR of 7.05 percent.

2023 General Rate Cases

We expect to file electric and natural gas general rate cases with IPUC in the first half of 2023.

Oregon General Rate Cases and Other Proceedings

2020 General Rate Case

In March 2020, we filed a natural gas general rate case with the OPUC. Through several settlement stipulations the parties resolved all issues and, in December 2020, the OPUC approved all stipulations.

The new rates were designed to increase annual base revenue by $3.9 million, or 5.7 percent effective January 16, 2021, reflecting an ROE of 9.4 percent, with a common equity ratio of 50 percent and a ROR of 7.24 percent.

2021 General Rate Case

In October 2021, we filed a natural gas general rate case with the OPUC. The proposal is designed to increase overall natural gas base revenue by $3.8 million and is based on a proposed ROR of 7.35 percent with a common equity ratio of 50 percent and a 9.9 percent ROE. We have proposed that the increase be fully offset for a two-year period with tax customer credits (related to the flow through of certain tax items) of the same amount.

In January 2022, a partial settlement stipulation was filed with the OPUC that addressed cost of capital issues. The parties agreed to an overall ROR of 7.05 percent based on a 50 percent common equity ratio and ROE of 9.4 percent.

Alaska Electric Light and Power Company

AEL&P is required to file its next general rate case by August 30, 2022.

Avista Utilities

Purchased Gas Adjustments

PGAs are designed to pass through changes in natural gas costs to Avista Utilities' customers with no change in utility margin (operating revenues less resource costs) or net income. In Oregon, we absorb (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 among all jurisdictions were a net asset of $21.0 million as of December 31, 2021 and $1.4 million as of December 31, 2020. These deferred natural gas cost balances represent amounts due from customers.

The following PGAs went into effect in our various jurisdictions during 2019 through 2022:

Jurisdiction	PGA Effective Date	Percentage Increase / (Decrease) in Billed Rates
Washington	November 1, 2019	10.4%
	November 1, 2020	(0.1)%
	November 1, 2021	10.6%
Idaho	November 1, 2019	5.6%
	November 1, 2020	0.7%
	September 1, 2021	13.5%
	February 1, 2022	7.6%
Oregon	November 1, 2019	4.7%
	November 1, 2020	2.8%
	November 1, 2021	9.6%

Power Cost Deferrals and Recovery Mechanisms

Deferred power supply costs are recorded as a deferred charge or liability on the Consolidated 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 Utilities and the costs included in base retail rates. These differences primarily result from changes in:

- short-term wholesale market prices and sales and purchase volumes,
- the level, availability and optimization of hydroelectric generation,
- the level, availability and optimization of thermal generation (including changes in fuel prices),
- retail loads, and
- sales of surplus transmission capacity.

For our Washington customers, the ERM is an accounting method used to track certain differences between Avista Utilities' actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base retail rates. Total net deferred power costs under the ERM were liabilities of $11.9 million as of December 31, 2021 and $37.9 million as of December 31, 2020. These deferred power cost balances represent amounts due to customers.

Under the ERM, Avista Utilities absorbs the cost or receives the benefit from the initial amount of power supply costs in excess of or below the level in retail rates, which is referred to as the deadband. The annual (calendar year) deadband amount is $4.0 million.

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%

Under the ERM, Avista Utilities 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.

Pursuant to WUTC requirements, should the cumulative deferral balance exceed $30 million (in either direction), we must make a filing with the WUTC to adjust customer rates to either return the balance to customers or recover the balance from customers. The cumulative rebate balance as of December 31, 2019 exceeded $30 million and as a result, our 2019 filing contained a proposed rate refund. The ERM proceeding was considered with our 2019 general rate case proceeding and a refund was approved and is being returned to customers over a two-year period that began on April 1, 2020. See further discussion in the section "Washington General Rate Cases" above.

Avista Utilities has a PCA mechanism in Idaho that allows us to modify electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, we defer 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for our Idaho customers. The October 1 rate adjustments recover or rebate power supply costs deferred during the preceding July–June twelve-month period. Total net power supply costs deferred under the PCA mechanism were an asset of $10.8 million as of December 31, 2021 and $2.5 million as of December 31, 2020. These deferred power cost balances represent amounts due from customers.

Decoupling and Earnings Sharing Mechanisms

Decoupling (also known as a FCA in Idaho) is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. In each of our jurisdictions, Avista Utilities' 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 our decoupling mechanisms.

Washington Decoupling and Earnings Sharing

In our 2019 Washington general rate cases, the WUTC approved an extension of the mechanisms for an additional five-year term through March 31, 2025, with one modification in that new customers added after any test period would not be 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. If we earn more than our authorized ROR in Washington, 50 percent of excess earnings are rebated to customers through adjustments to existing decoupling surcharge or rebate balances. We have proposed to modify this earnings test in our 2022 general rate case, so that if the Company earns more than 0.5 percent higher than the ROR authorized by the WUTC in the multi-year rate plan, the Company would defer these excess revenues and later return them to customers.

Idaho FCA Mechanism

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

Oregon Decoupling Mechanism

In Oregon, we have a decoupling mechanism for natural gas. An earnings review is conducted on an annual basis. In the annual earnings review, if we earn more than 100 basis points above our allowed return on equity, one-third of the earnings above the 100 basis points would be deferred and later rebated to customers.

Cumulative Decoupling and Earnings Sharing Balances

Total net cumulative decoupling deferrals among all jurisdictions were regulatory assets of $15.2 million as of December 31, 2021 and $21.3 million as of December 31, 2020. These decoupling assets represent amounts due from customers. Total net earnings sharing balances among all jurisdictions were regulatory liabilities of $0.7 million as of December 31, 2021 and December 31, 2020. These earnings sharing liabilities represent amounts due to customers.

See "Results of Operations—Avista Utilities" for further discussion of the amounts recorded to operating revenues in 2021 and 2020 related to the decoupling and earnings sharing mechanisms.

COVID-19 Deferrals

See "Note 1 of the Notes to Consolidated Financial Statements" for discussion on COVID-19 deferrals.

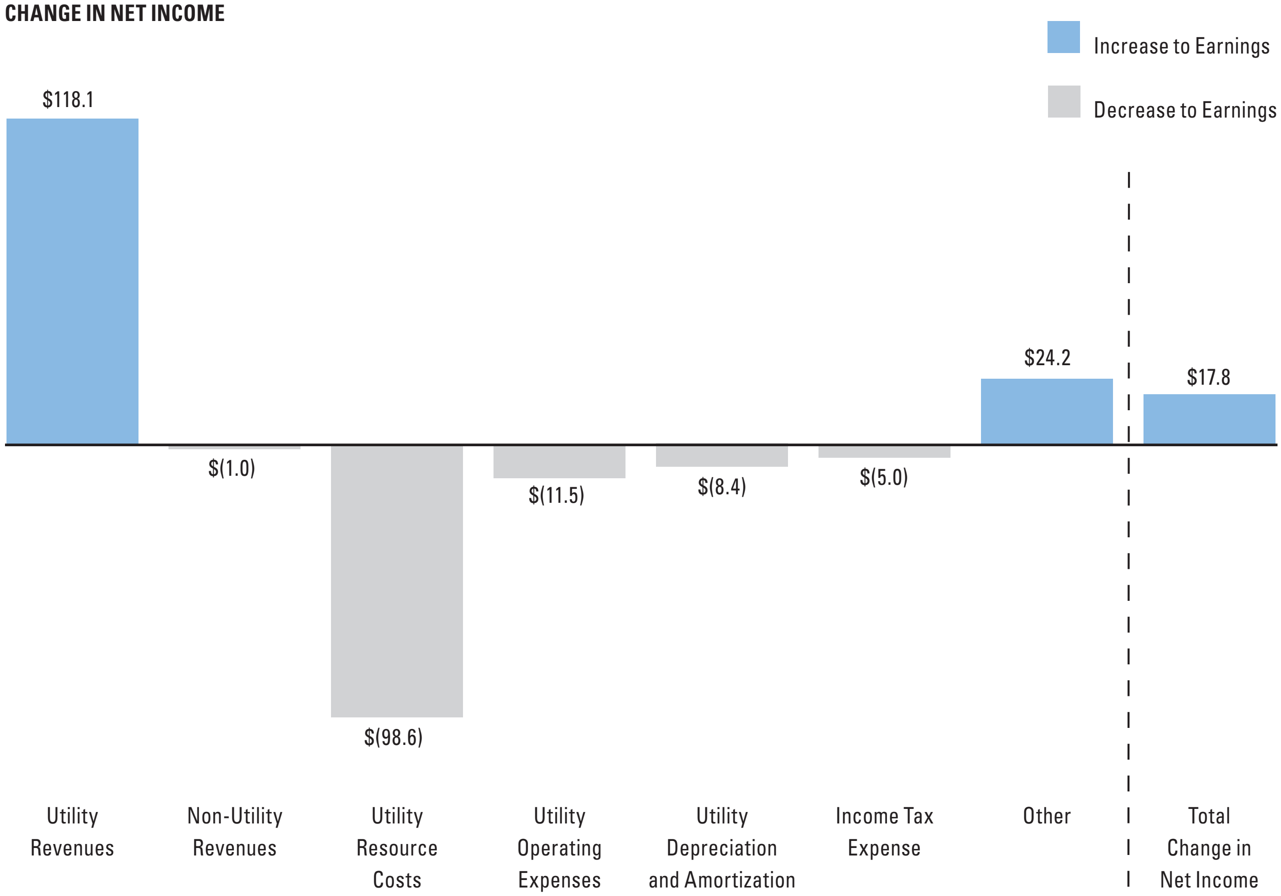
Results of Operations–Overall

The following provides an overview of changes in our Consolidated Statements of Income. More detailed explanations are provided, particularly for operating revenues and operating expenses, in the business segment discussions (Avista Utilities, AEL&P and the other businesses) that follow this section.

2021 compared to 2020

The following graph shows the total change in net income attributable to Avista Corp. shareholders for 2021 to 2020, as well as the various factors that caused such change (dollars in millions):

CHANGE IN NET INCOME



Utility revenues increased at Avista Utilities primarily due to increased loads from non-decoupled customers as a result of reduced COVID-19 restrictions during 2021, as well as weather that was warmer than normal and warmer than the prior year. In addition, utility revenues increased due to general rate increases in Oregon (effective January 16, 2021) and Washington (effective April 1, 2020), as well as customer growth. In addition, in 2020 there was a $4.9 million decrease to revenue due to the outcome of the 2015 Washington general rate cases.

Utility resource costs increased at Avista Utilities due to increased purchased power, fuel for generation and other fuel costs, as well as higher natural gas purchases. See "Summer Weather Conditions" in the Executive Level Summary on page 28 for further discussion of increased net power supply costs.

The increase in utility operating expenses was primarily due to increases in insurance, information technology, and labor and benefits costs at Avista Utilities, as well as a $2.5 million write off of Colstrip SmartBurn technology assets disallowed under the Washington general rate case settled during 2021. The increases were partially offset by an accrual recorded in 2020 for disallowed replacement power during an unplanned outage at Colstrip.

Utility depreciation and amortization increased primarily due to additions to utility plant during the period. This was partially offset by a one-time increase to depreciation expense in 2020 as we were able to utilize $10.9 million ($8.4 million when tax-effected) of electric tax benefits to offset costs associated with accelerating the deprecation of Colstrip based on a settlement in Washington.

Income taxes increased primarily due to a decrease in tax expense during 2020 related to the offset of $8.4 million of deferred income taxes against accelerated depreciation for Colstrip based on a settlement in Washington and an increase in pre-tax earnings. This was offset by a change in tax methodology to the flow through method for certain items in 2021, as accepted by IPUC and WUTC through our general rate cases. Our effective tax rate was 7.5 percent in 2021 compared to 5.2 percent in 2020. See "Note 12 of the Notes to Condensed Consolidated Financial Statements" for further details and a reconciliation of our effective tax rate.

The increase in other was primarily related to net investment gains during 2021, compared to net investment losses experienced during 2020 (including impairment and write off of notes receivable). Additionally, other increased due to the gain on sale of certain subsidiary assets associated with the Spokane Steam Plant in 2021.

Non-GAAP Financial Measures

The following discussion for Avista Utilities includes two financial measures that are considered "non-GAAP financial measures," electric utility margin and natural gas utility margin. In the AEL&P section, we include a discussion of utility margin, which is also a non-GAAP financial measure.

Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are included (excluded) in the most directly comparable measure calculated and presented in accordance with GAAP. Electric utility margin is electric operating revenues less electric resource costs, while natural gas utility margin is natural gas operating revenues less natural gas resource costs. The most directly comparable GAAP financial measure to electric and natural gas utility margin is utility operating revenues as presented in "Note 24 of the Notes to Consolidated Financial Statements."

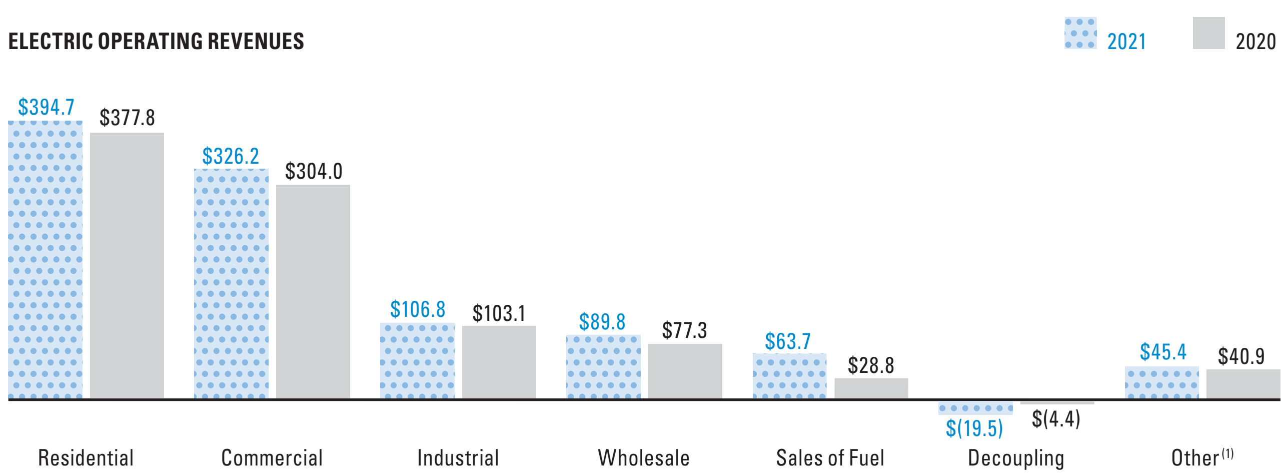
The presentation of electric utility margin and natural gas utility margin is intended to enhance understanding of our operating performance. We use these measures internally and believe they provide useful information to investors in their analysis of how changes in loads (due to weather, economic or other conditions), rates, supply costs and other factors impact our results of operations. Changes in loads, as well as power and natural gas supply costs, are generally deferred and recovered from customers through regulatory accounting mechanisms. Accordingly, the analysis of utility margin generally excludes most of the change in revenue resulting from these regulatory mechanisms. We present electric and natural gas utility margin separately below for Avista Utilities since each business has different cost sources, cost recovery mechanisms and jurisdictions, so we believe that separate analysis is beneficial. These measures are not intended to replace utility operating revenues as determined in accordance with GAAP as an indicator of operating performance. Reconciliations of operating revenues to utility margin are set forth below.

Results of Operations–Avista Utilities

2021 compared to 2020

Utility Operating Revenues

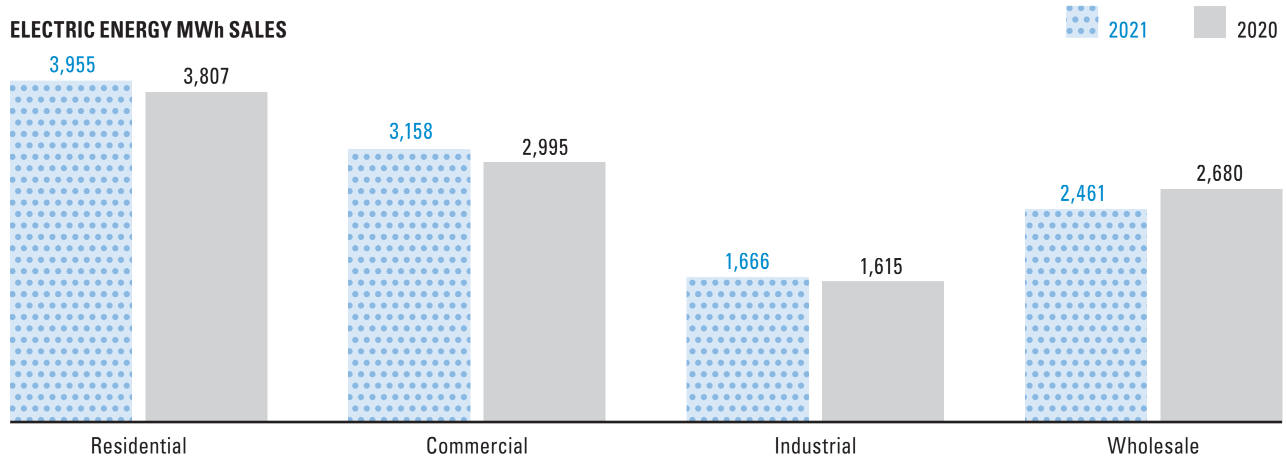
The following graphs present Avista Utilities' electric operating revenues and megawatt-hour (MWh) sales for the years ended December 31 (dollars in millions and MWhs in thousands):



(1) This balance includes public street and highway lighting, which is considered part of retail electric revenues, and deferrals/amortizations to customers related to federal income tax law changes.

Total electric operating revenues in the graph above include intracompany sales of $28.7 million and $36.4 million for 2021 and 2020, respectively.

ELECTRIC ENERGY MWh SALES



The following table presents the current year deferrals and the amortization of prior year decoupling balances that are reflected in utility electric operating revenues for the years ended December 31 (dollars in thousands):

	Electric Operating Revenues	
	2021	2020
Current year decoupling deferrals [a]	$ (6,053)	$ 11,449
Amortization of prior year decoupling deferrals [b]	(13,472)	(15,810)
Total electric decoupling revenue	$ (19,525)	$ (4,361)

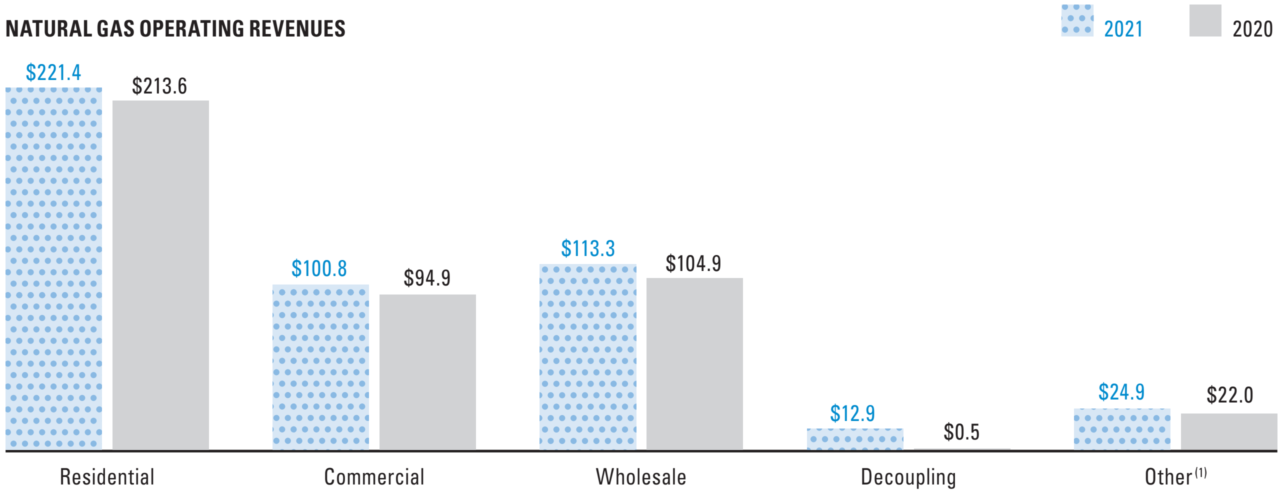
(a) Positive amounts are increases in decoupling revenue in the current year and will be surcharged to customers in future years. Negative amounts are decreases in decoupling revenue in the current year and will be rebated to customers in future years.

(b) Negative amounts are decreases in decoupling revenue in the current year and are related to the amortization of surcharge balances that resulted in prior years and are being surcharged to customers (causing a corresponding increase in retail revenue from customers) in the current year. Positive amounts are increases in decoupling revenue in the current year and are related to the amortization of rebate balances that resulted in prior years and are being refunded to customers (causing a corresponding decrease in retail revenue from customers) in the current year.

Total electric revenues increased $79.6 million for 2021 as compared to 2020. The primary fluctuations that occurred during the period were as follows:

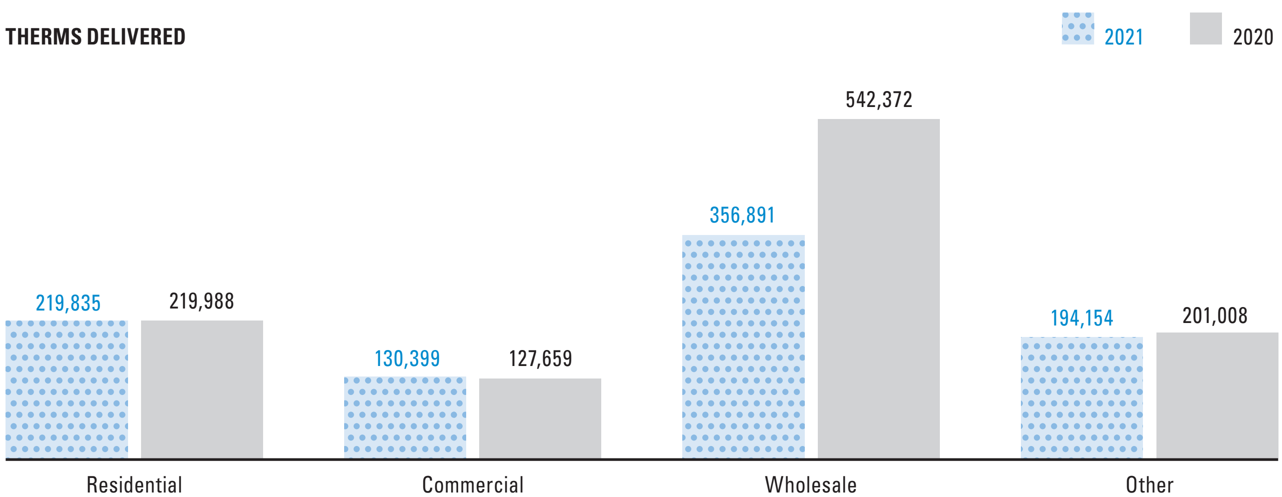
- a $43.0 million increase in retail electric revenues due to an increase in total MWhs sold (increased revenues $34.3 million), as well as an increase in revenue per MWh (increased revenues $8.7 million).
  - The increase in total retail MWhs sold was primarily the result of weather that was warmer than normal throughout the summer months, which increased cooling loads. Cooling degree days in Spokane during 2021 were 73 percent above historical norms, compared to 2 percent above historical norms in 2020. Also, there was a lifting of COVID-19 restrictions throughout 2021, which contributed to the increased loads and customer growth. Compared to 2020, use per residential customer increased 2.2 percent, and use per commercial customer increased 4.0 percent.
  - The increase in revenue per MWh was primarily due to base rate increases in Washington, effective April 1, 2020, as well as passthrough rate changes, which do not have an impact on utility margin, such as the residential exchange program, low income rate assistance program, the ERM and PCA amortization rates and decoupling.
- a $12.5 million increase in wholesale electric revenues due to an increase in sales prices (increased revenues $20.5 million), partially offset by a decrease in sales volumes (decreased revenues $8.0 million). The fluctuation of volumes was due to our need to utilize our thermal generation assets more than normal due to lower than normal hydroelectric generation and increased customer loads, which limited our opportunities to sell generation in the wholesale power markets compared to 2020.
- a $34.9 million increase in sales of fuel due to thermal generation resource optimization activities.
- a $15.1 million decrease in electric decoupling revenue. This is primarily due to 2020 resulting in surcharges to non-residential customers, which had lower usage due to COVID-19 restrictions. In 2021, we experienced a rebate position due to higher than normal usage from warmer than normal weather in the cooling season, as well as lifting COVID-19 restrictions.
- a $4.5 million increase in other revenues primarily due to an increase in transmission revenues of $2.8 million as well as an accrual for customer refunds recorded in 2020 for $1.4 million related to our 2015 Washington general rate case.

The following graphs present Avista Utilities' natural gas operating revenues and therms delivered for the years ended December 31 (dollars in millions and therms in thousands):



(1) *This balance includes interruptible and industrial revenues, which are considered part of retail natural gas revenues, and deferrals/amortizations to customers related to federal income tax law changes.*

Total natural gas operating revenues in the graph above include intracompany sales of $58.6 million and $49.6 million for 2021 and 2020, respectively.



The following table presents the current year deferrals and the amortization of prior year decoupling balances that are reflected in natural gas operating revenues for the years ended December 31 (dollars in thousands):

	Natural Gas Operating Revenues	
	2021	**2020**
Current year decoupling deferrals [a]	$ 11,129	$ 1,797
Amortization of prior year decoupling deferrals [b]	1,761	(1,250)
Total natural gas decoupling revenue	$ 12,890	$ 547

(a) *Positive amounts are increases in decoupling revenue in the current year and will be surcharged to customers in future years. Negative amounts are decreases in decoupling revenue in the current year and will be rebated to customers in future years.*

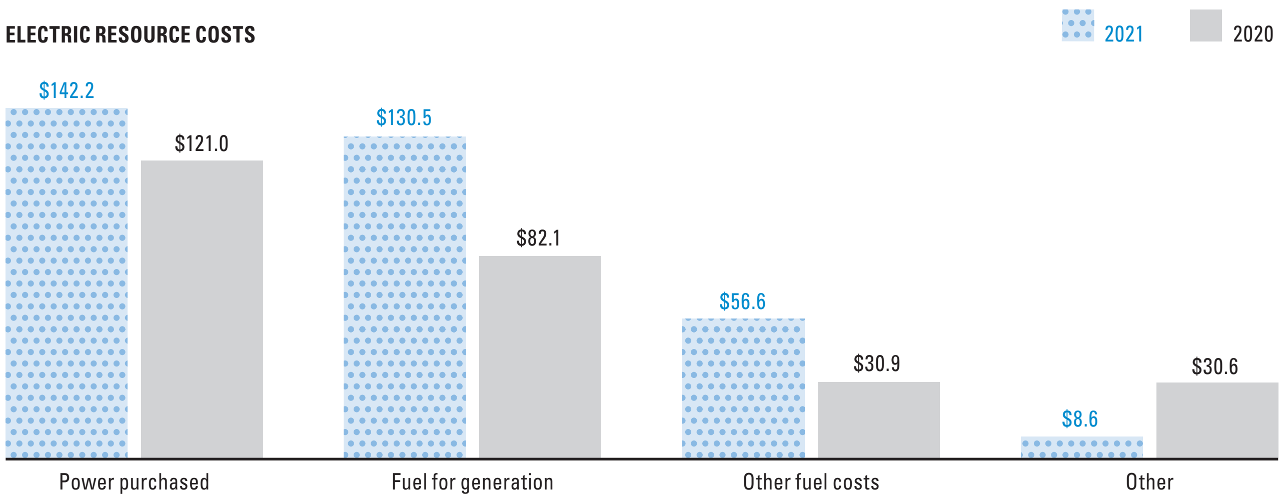
(b) *Positive amounts are increases in decoupling revenue in the current year and are related to the amortization of rebate balances that resulted in prior years and are being refunded to customers (causing a corresponding decrease in retail revenue from customers) in the current year. Negative amounts are decreases in decoupling revenue in the current year and are related to the amortization of surcharge balances that resulted in prior years and are being surcharged to customers (causing a corresponding increase in retail revenue from customers) in the current year.*

Total natural gas revenues increased $37.4 million for 2021 as compared to 2020. The primary fluctuations that occurred during the period were as follows:

- a $14.3 million increase in retail natural gas revenues (including industrial, which is included in other) due to higher retail rates (increased revenues $11.0 million), and higher sales volumes (increased revenues $3.3 million).
  - Retail rates increased due to general rate increases in Oregon (effective January 16, 2021), and Washington (effective April 1, 2020). Increases were also due to PGA rate increases, which do not impact utility margin.
  - Retail natural gas sales increased primarily due to higher commercial and industrial usage, as well as slight residential customer growth.
- an $8.4 million increase in wholesale natural gas revenues due to an increase in prices (increased revenues $67.2 million) offset by a decrease in volumes (decreased revenues $58.8 million) due to fewer resource optimization opportunities. Differences between revenues and costs from sales of resources in excess of retail load requirements and from resource optimization are accounted for through the PGA mechanisms.
- a $12.4 million increase in decoupling revenues primarily increased in decoupling revenues related to warmer weather in 2021 compared to 2020. In addition, during 2020 we were amortizing decoupling surcharges, whereas in 2021 we are amortizing decoupling rebates.
- a $2.9 million increase in other revenues primarily related to an accrual in 2020 of $3.6 million for customer refunds related to our 2015 Washington general rate case.

Utility Resource Costs

The following graphs present Avista Utilities' resource costs for the years ended December 31 (dollars in millions):

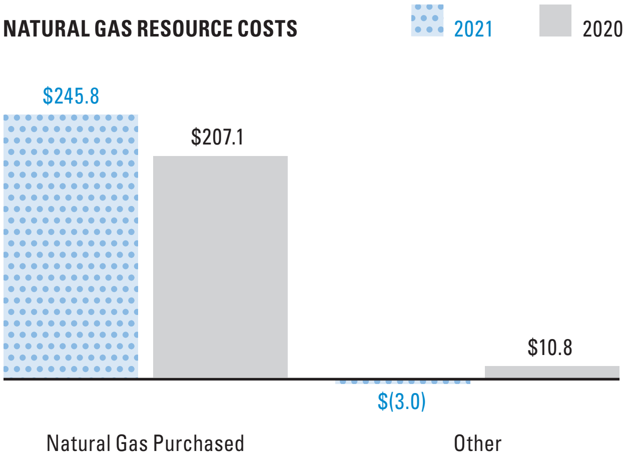


Total electric resource costs in the graph above include intracompany resource costs of $58.6 million and $49.6 million for 2021 and 2020, respectively.

Total electric resource costs increased $73.3 million for 2021 as compared to 2020. The primary fluctuations that occurred during the period were as follows:

- a $21.2 million increase in power purchased due to an increase in wholesale prices (increased costs by $18.6 million), and an increase in the volume of power purchases (increased costs by $2.6 million). The fluctuation in volumes was primarily the result of changes in how we were able to optimize our generation assets as compared to the prior year. Additionally, over the summer months of 2021, we had increased customer loads and lower than normal hydroelectric generation as a result of excessive heat in the Pacific Northwest, which contributed to our need to purchase power at increased prices. See "Summer Weather Conditions" in the Executive Level Summary on page 28.
- a $48.4 million increase in fuel for generation primarily due to a decrease in hydroelectric generation requiring additional thermal generation. There was also an increase in natural gas prices in 2021 compared to 2020.
- a $25.7 million increase in other fuel costs. This represents fuel and the related derivative instruments that were purchased for generation but later sold when conditions indicated that it was more economical to sell the fuel as part of the resource optimization process. When the fuel or related derivative instruments are sold, that revenue is included in sales of fuel.
- a $22.0 million decrease in other electric resource costs, primarily related to the deferral of increased power supply costs above authorized. There was also increased amortizations associated with the Washington ERM.

NATURAL GAS RESOURCE COSTS



Total natural gas resource costs in the graph at left include intracompany resource costs of $28.7 million and $36.4 million for 2021 and 2020, respectively.

Total natural gas resource costs increased $24.9 million for 2021 as compared to 2020. The primary fluctuations that occurred during the period were as follows:

- a $38.7 million increase in natural gas purchased due to increases in the price of natural gas (increased costs by $100.0 million) which was partially offset by a decrease in total therms purchased (decreased costs $61.3 million).
- a $13.8 million decrease from net amortizations and deferrals of natural gas costs.

Utility Margin

The following table reconciles Avista Utilities' operating revenues, as presented in "Note 24 of the Notes to Consolidated Financial Statements" to the Non-GAAP financial measure utility margin for the years ended December 31 (dollars in thousands):

	Electric		Natural Gas		Intracompany		Total	
	2021	2020	2021	2020	2021	2020	2021	2020
Operating revenues	$ 1,007,052	$ 927,540	$ 473,313	$ 435,882	$ (87,366)	$ (85,954)	$ 1,392,999	$ 1,277,468
Resource costs	337,866	264,595	242,789	217,902	(87,366)	(85,954)	493,289	396,543
Utility margin	$ 669,186	$ 662,945	$ 230,524	$ 217,980	$ —	$ —	$ 899,710	$ 880,925

Electric utility margin increased $6.2 million and natural gas utility margin increased $12.5 million.

Electric utility margin increased primarily due to customer growth and a general rate increase in Washington, effective April 1, 2020. In addition, 2020 included an accrual for customer refunds of $1.4 million related to our 2015 Washington general rate case. This was partially offset by an increase in net power supply costs as compared to the prior year due, in part, to the hot, dry weather conditions experienced in 2021 (see "Summer Weather Conditions" in the Executive Level Summary above). For 2021, we had a $7.7 million pre-tax expense under the ERM in Washington, compared to a $6.2 million pre-tax benefit in 2020.

Natural gas utility margin increased primarily due to general rate increases in Oregon (effective January 16, 2021) and Washington (effective April 1, 2020) as well as customer growth. The 2020 accrual for customer refunds of $3.5 million related to our 2015 Washington general rate case also contributed to the increase year over year.

Intracompany revenues and resource costs represent purchases and sales of natural gas between our natural gas distribution operations and our electric generation operations (as fuel for our generation plants). These transactions are eliminated in the presentation of total results for Avista Utilities and in the consolidated financial statements but are included in the separate results for electric and natural gas presented above.

Results of Operations—Alaska Electric Light and Power Company

2021 compared to 2020

Net income for AEL&P was $7.2 million for the year ended December 31, 2021, compared to $8.1 million for 2020. This decrease was primarily due a $1.0 million increase in other operating expenses.

The following table presents AEL&P's operating revenues, resource costs and resulting utility margin for the years ended December 31 (dollars in thousands):

	Electric	
	2021	2020
Operating revenues	$ 45,366	$ 42,809
Resource costs	3,834	1,966
Utility margin	$ 41,532	$ 40,843

Utility margin increased slightly for 2021 primarily due to higher sales volumes to residential and commercial customers for 2021 as compared to 2020.

Results of Operations—Other Businesses

2021 compared to 2020

Our other businesses had net income of $14.6 million for 2021 compared to net loss of $3.4 million for 2020. The increase in net income primarily relates to net investment gains during 2021.

Accounting Standards to be Adopted in 2022

At this time, we are not expecting the adoption of accounting standards to have a material impact on our financial condition, results of operations and cash flows in 2022. For information on accounting standards adopted in 2021 and accounting standards expected to be adopted in future periods, see "Note 2 of the Notes to Consolidated Financial Statements."

Critical Accounting Policies and Estimates

The preparation of our consolidated financial statements in conformity with GAAP requires us to make estimates and assumptions that affect amounts reported in the consolidated financial statements. Changes in these estimates and assumptions are considered reasonably possible and may have a material effect on our consolidated financial statements and thus actual results could differ from the amounts reported and disclosed herein. The following accounting policies represent those that our management believes are particularly important to the consolidated financial statements and require the use of estimates and assumptions:

- **Regulatory accounting,** in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 980, *Regulated Operations*, among other things, requires that costs and/or obligations that, in our judgement, are probable of recovery through rates charged to our customers, but are not yet reflected in rates, not be reflected in our Consolidated Statements of Income until the period in which they are reflected in rates and matching revenues are recognized. Meanwhile, these costs and/or obligations are deferred and reflected on our Consolidated Balance Sheets as regulatory assets or liabilities. We generally receive regulatory orders before deferring costs as regulatory assets and liabilities; however, in certain instances in which we have regulatory precedent, we may not request an order before deferring the costs. If we were no longer allowed to apply regulatory accounting or no longer allowed recovery of these costs, we could be required to recognize significant write-offs of regulatory assets and liabilities in the Consolidated Statements of Income. See "Notes 1, 4 and 23 of the Notes to Consolidated Financial Statements" for further discussion of our regulatory accounting policy and mechanisms.
- **Pension Plans and Other Postretirement Benefit Plans,** discussed in further detail below.
- **Contingencies,** related to unresolved regulatory, legal and tax issues as to which there is inherent uncertainty for the ultimate outcome of the respective matter. We accrue a loss contingency if it is probable that an asset is impaired or a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. We also disclose losses that do not meet these conditions for accrual, if there is a reasonable possibility that a potential loss may be incurred. For all material contingencies, we have made a judgment as to the probability of a loss occurring and as to whether or not the amount of the loss can be reasonably estimated. However, no assurance can be given as to the ultimate outcome of any particular contingency. See "Notes 1 and 22 of the Notes to Consolidated Financial Statements" for further discussion of our commitments and contingencies.

Pension Plans and Other Postretirement Benefit Plans–Avista Utilities

We have a defined benefit pension plan covering substantially all regular full-time employees at Avista Utilities that were hired prior to January 1, 2014. For substantially all regular non-union full-time employees at Avista Utilities who were hired on or after January 1, 2014, a defined contribution 401(k) plan replaced the defined benefit pension plan. Union employees hired on or after January 1, 2014 are still covered under the defined benefit pension plan. See "Note 11 of the Notes to Consolidated Financial Statements" for further discussion of these individual plans.

Pension costs (including the SERP) were $19.3 million for 2021, $22.3 million for 2020 and $26.9 million for 2019. Of our pension costs (excluding the SERP), approximately 60 percent are expensed and 40 percent are capitalized consistent with labor charges. The costs related to the SERP are expensed. Our costs for the pension plan are determined in part by actuarial formulas that are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

Pension costs are affected by among other things:

- employee demographics (including age, compensation and length of service by employees),
- the amount of cash contributions we make to the pension plan,
- the actual return on pension plan assets,
- expected return on pension plan assets,
- discount rate used in determining the projected benefit obligation and pension costs,
- assumed rate of increase in employee compensation,
- life expectancy of participants and other beneficiaries, and
- expected method of payment (lump sum or annuity) of pension benefits.

We have to make estimates and assumptions as to many of these factors. In accordance with accounting standards, changes in pension plan obligations associated with these factors may not be immediately recognized as pension costs in our Consolidated Statements of Income, but we generally recognize the change in future years over the remaining average service period of pension plan participants. As such, our costs recorded in any period may not reflect the actual level of cash benefits provided to pension plan participants.

We revise the key assumption of the discount rate each year. In selecting a discount rate, we consider yield rates at the end of the year for highly rated corporate bond portfolios with cash flows from interest and maturities similar to that of the expected payout of pension benefits.

The expected long-term rate of return on plan assets is reset or confirmed annually based on past performance and economic forecasts for the types of investments held by our plan.

The following chart reflects the assumptions used each year for the pension discount rate (exclusive of the SERP), the expected long-term return on plan assets and the actual return on plan assets and their impacts to the pension plan associated with the change in assumption (dollars in millions):

	2021	2020	2019
Discount rate (exclusive of SERP)			
Pension discount rate	3.39%	3.25%	3.85%
Increase/(decrease) to projected benefit obligation	$ (15.6)	$ 62.6	$ 41.7
Return on plan assets [(a)]			
Expected long-term return on plan assets	5.40%	5.50%	5.90%
Increase/(decrease) to pension costs	$ 0.7	$ 2.5	$ (2.2)
Actual return on plan assets—net of fees	7.10%	15.20%	20.40%
Actual gain on plan assets	$ 50.4	$ 96.6	$ 109.9

(a) The SERP has no plan assets. The plan assets in this disclosure are for the pension plan only.

The following chart reflects the sensitivities associated with a change in certain actuarial assumptions by the indicated percentage (dollars in millions):

Actuarial Assumption	Change in Assumption	Effect on Projected Benefit Obligation	Effect on Pension Cost
Expected long-term return on plan assets	(0.5)%	$ —*	$ 3.6
Expected long-term return on plan assets	0.5%	—*	(3.6)
Discount rate	(0.5)%	58.2	5.3
Discount rate	0.5%	(51.7)	(4.7)

** Changes in the expected return on plan assets would not affect our projected benefit obligation.*

We provide certain health care and life insurance benefits for substantially all of our retired employees. We accrue the estimated cost of postretirement benefit obligations during the years that employees provide service.

Liquidity and Capital Resources

Overall Liquidity

Avista Corp.'s consolidated operating cash flows are primarily derived from the operations of Avista Utilities. The primary source of operating cash flows for Avista Utilities is revenues from sales of electricity and natural gas. Significant uses of cash flows from Avista Utilities include the purchase of power, fuel and natural gas, and payment of other operating expenses, taxes and interest, with any excess being available for other corporate uses such as capital expenditures and dividends.

We design operating and capital budgets to control operating costs and to direct capital expenditures to projects that support immediate and long-term strategies, particularly for our regulated utility operations. In addition to operating expenses, we have continuing commitments for capital expenditures for construction and improvement of utility facilities.

Our annual net cash flows from operating activities usually do not fully support the amount required for annual utility capital expenditures. As such, from time-to-time, we need to access capital markets in order to fund these needs as well as fund maturing debt. See further discussion at "Capital Resources."

We periodically file for rate adjustments for recovery of operating costs and capital investments and to seek the opportunity to earn reasonable returns as allowed by regulators.

Avista Utilities has regulatory mechanisms in place that provide for the deferral and recovery of the majority of power and natural gas supply costs. However, when power and natural gas costs exceed the levels currently recovered from retail customers, net cash flows are negatively affected. Factors that could cause purchased power and natural gas costs to exceed the levels currently recovered from our customers include, but are not limited to, higher prices in wholesale markets when we buy energy or an increased need to purchase power in the wholesale markets, and a lack of regulatory approval for higher authorized net power supply costs through general rate case decisions. Factors beyond our control that could result in an increased need to purchase power in the wholesale markets include, but are not limited to:

- increases in demand (due to either climate change/weather or customer growth),
- reduced snowpack or lower streamflows (due to climate change/weather) for hydroelectric generation,
- unplanned outages at generating facilities, and
- failure of third parties to deliver on energy or capacity contracts.

In addition to the above, Avista Utilities enters into derivative instruments to hedge our exposure to certain risks, including fluctuations in commodity market prices, foreign exchange rates and interest rates (for purposes of issuing long-term debt in the future). These derivative instruments 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 a downgrade in the Company's credit ratings or changes in market prices. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against the Company's credit facilities and cash. See "Enterprise Risk Management—Credit Risk Liquidity Considerations" below.

We monitor the potential liquidity impacts of changes to energy commodity prices and other increased operating costs for our utility operations. We believe that we have adequate liquidity to meet such potential needs through our committed lines of credit.

Material contractual obligations arising in the normal course of business include energy purchase contracts, and contractual obligations related to generation facilities and transmission and distributions services. See "Note 13 of the Notes to Consolidated Financial Statements" for additional information related to these contractual obligations.

Additional capital resource requirements include borrowings and interest payment obligations (see "Notes 14-17 of the Notes to Consolidated Financial Statements"), lease obligations (see "Note 5 of the Notes to Consolidated Financial Statements"), pension and other postretirement benefit plan contributions (see "Note 11 of the Notes to Consolidated Financial Statements") and investment fund commitments (see "Note 6 of the Notes to Consolidated Financial Statements").

As of December 31, 2021, we had $82.0 million of available liquidity under the Avista Corp. committed line of credit and $25.0 million under the AEL&P committed line of credit. With our $400.0 million credit facility that expires in June 2026 and AEL&P's $25.0 million credit facility that expires in November 2024, we believe that we have adequate liquidity to meet our needs for the next 12 months.

Review of Consolidated Cash Flow Statement

2021 compared to 2020

Consolidated Operating Activities

Net cash provided by operating activities was $267.3 million for 2021 compared to $331.0 million for 2020. The decrease in net cash provided by operating activities primarily relates to an increase in power and natural gas cost deferrals (reflecting higher power and natural gas supply costs), which decreased cash flows by $51.8 million in 2021 compared to decreasing cash flows by $9.9 million in 2020. In addition, the provision for deferred taxes increased in 2021 less than it did during 2020, decreasing operating cash flows by $33.7 million compared to 2020. Finally, there was also an increase in pension contributions made during the year, from $22.0 million in 2020 to $42.0 million in 2021.

These decreases were partially offset by changes in certain current assets and liabilities, which increased cash flows by $26.3 million.

Consolidated Investing Activities

Net cash used in investing activities was $444.9 million for 2021, an increase compared to $410.7 million for 2020. During 2021, we paid $439.9 million for utility capital expenditures, compared to $404.3 million for 2020.

Consolidated Financing Activities

Net cash provided by financing activities was $185.5 million for 2021 compared to $84.0 million for 2020. The increase in financing cash flows was primarily the result of changes in short-term borrowings of $63.8 million compared to 2020. In addition, there was an increase in proceeds from issuance of common stock of $17.8 million compared to 2020.

Capital Resources

Capital Structure

Our consolidated capital structure, including the current portion of long-term debt and short-term borrowings consisted of the following as of December 31, 2021 and 2020 (dollars in thousands):

	2021		2020	
	Amount	Percent of Total	Amount	Percent of Total
Current portion of long-term debt and leases	$ 257,386	5.4%	$ 7,184	0.2%
Short-term borrowings	284,000	6.0%	203,000	4.6%
Long-term debt to affiliated trusts	51,547	1.1%	51,547	1.2%
Long-term debt and leases	2,010,168	42.2%	2,125,065	48.0%
Total debt	2,603,101	54.7%	2,386,796	54.0%
Total Avista Corporation shareholders' equity	2,154,744	45.3%	2,029,726	46.0%
Total	$ 4,757,845	100.0%	$ 4,416,522	100.0%

Our shareholders' equity increased $125.0 million during 2021 primarily due to net income and the issuance of common stock, partially offset by dividends.

We need to finance capital expenditures and acquire additional funds for operations from time-to-time. The cash requirements needed to service our indebtedness, both short-term and long-term, reduce the amount of cash flow available to fund capital expenditures, purchased power, fuel and natural gas costs, dividends and other requirements.

Committed Lines of Credit

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million. In June 2021, we entered into an amendment that extends the expiration date to June

2026, with the option to extend for an additional one year period (subject to customary conditions). As of December 31, 2021, there was $82.0 million of available liquidity under this line of credit.

The Avista Corp. credit facility contains customary covenants and default provisions, including a covenant which does not permit our ratio of "consolidated total debt" to "consolidated total capitalization" to be greater than 65 percent at any time. As of December 31, 2021, we were in compliance with this covenant with a ratio of 54.7 percent.

Balances outstanding and interest rates on borrowings (excluding letters of credit) under Avista Corp.'s committed line of credit were as follows as of and for the year ended December 31 (dollars in thousands):

		2021		2020
Balance outstanding at end of year	$	284,000	$	102,000
Letters of credit outstanding at end of year (1)	$	34,000	$	27,618
Maximum balance outstanding during the year	$	338,000	$	310,000
Average balance outstanding during the year	$	208,629	$	138,890
Average interest rate during the year		1.14%		1.59%
Average interest rate at end of year		1.11%		1.22%

(1) Letters of credit represent off-balance sheet obligations.

AEL&P has a $25.0 million committed line of credit with an expiration date in November 2024. As of December 31, 2021, there was $25.0 million of available liquidity under this line of credit.

The AEL&P credit facility contains customary covenants and default provisions including a covenant which does not permit the ratio of "consolidated total debt at AEL&P" to "consolidated total capitalization at AEL&P," (including the impact of the Snettisham obligation) to be greater than 67.5 percent at any time. As of December 31, 2021, AEL&P was in compliance with this covenant with a ratio of 51.9 percent.

As of December 31, 2021, Avista Corp. and its subsidiaries were in compliance with all of the covenants of their financing agreements, and none of Avista Corp.'s subsidiaries constituted a "significant subsidiary" as defined in Avista Corp.'s committed line of credit.

In April 2020, we entered into a $100.0 million credit agreement with an expiration date of April 2021. We borrowed the entire $100.0 million available under this agreement in April 2020 and repaid the outstanding balance in April 2021. See "Note 15 of the Notes to Consolidated Financial Statements."

Long-Term Debt

In September 2021, we issued and sold $70.0 million of 2.90 percent first mortgage bonds due in 2051 pursuant to a bond purchase agreement with institutional investors in the private placement market. We issued and sold the remaining $70.0 million under this same bond agreement in December 2021. The total net proceeds from the sale of the bonds were used to repay a portion of the outstanding balance under our $400.0 million committed line of credit. In connection with the pricing of the first mortgage bonds in September 2021, we cash-settled four interest rate swap derivatives (notional aggregate amount of $45.0 million) and paid a net amount of $17.2 million, which will be amortized as a component of interest expense over the life of the debt. The effective interest rate of the first mortgage bonds is 3.63 percent, including the effects of the settled interest rate swap derivatives and issuance costs.

Common Stock

We issued common stock in 2021 for total net proceeds of $90.0 million. Most of these issuances came through our sales agency agreements under which the sales agents may offer and sell new shares of our common stock from time-to-time. We have board and regulatory authority to issue a maximum of 4.3 million shares, of which 2.1 million remain unissued as of December 31, 2021. In 2021, 2.2 million shares were issued under these agreements resulting in total net proceeds of $88.5 million.

2022 and 2023 Liquidity Expectations

During 2022, we expect to issue $400.0 million of long-term debt and $120.0 million of common stock in order to refinance $250 million of first mortgage bonds maturing on April 2, 2022 and to fund capital expenditures.

During 2023, we expect to issue $110 million of long-term debt and $110 million of common stock to fund planned capital expenditures.

After considering the expected issuances of long-term debt and common stock during 2022 and 2023, we expect net cash flows from operating activities, together with cash available under our committed line of credit agreements, to provide adequate resources to fund capital expenditures, dividends, and other contractual commitments.

Limitations on Issuances of Preferred Stock and First Mortgage Bonds

We are restricted under our Restated Articles of Incorporation, as amended, as to the additional preferred stock we can issue. As of December 31, 2021, we could issue $1.5 billion of preferred stock at an assumed dividend rate of 4.6 percent. We are not planning to issue preferred stock.

Under the Avista Corp. and the AEL&P Mortgages and Deeds of Trust securing Avista Corp.'s and AEL&P's first mortgage bonds (including Secured Medium-Term Notes), respectively, each entity may issue additional first mortgage bonds in an aggregate principal amount equal to the sum of:

- 66⅔ percent of the cost or fair value (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.

However, Avista Corp. and AEL&P 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 the respective Mortgages) 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 that entity's 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, 2021, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.8 billion in aggregate principal amount of additional first mortgage bonds at Avista Corp. and $38.2

million at AEL&P, at an assumed interest rate of 8 percent in each case. We believe that we have adequate capacity to issue first mortgage bonds to meet our financing needs over the next several years.

Utility Capital Expenditures

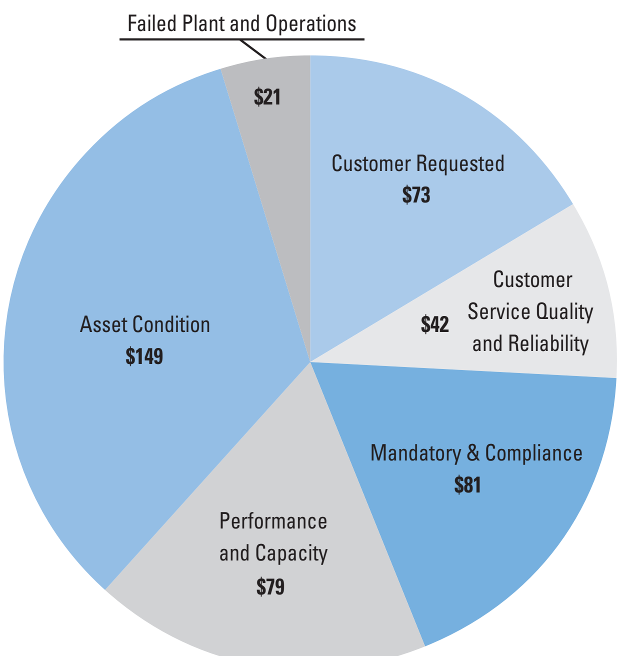
We are making capital investments at our utilities to enhance service and system reliability for our customers and replace aging infrastructure.

The following table summarizes our actual and expected capital expenditures as of and for the year ended December 31, 2021 (in thousands):

	Avista Utilities	AEL&P
2021 Actual capital expenditures		
Capital expenditures (per the Consolidated Statement of Cash Flows)	$ 435,887	$ 4,052
Expected total annual capital expenditures (by year)		
2022	$ 445,000	$ 14,000
2023	445,000	13,000
2024	445,000	12,000

The following graph shows Avista Utilities' expected capital expenditures for 2022 by category (in millions):

CAPITAL BUDGET AT AVISTA UTILITIES FOR 2022 (dollars in millions)



These estimates of capital expenditures are subject to continuing review and adjustment. Actual expenditures may vary from our estimates due to factors such as changes in business conditions, construction schedules and environmental requirements.

Non-Regulated Investments and Capital Expenditures

We are making investments and capital expenditures at our other businesses including those related to economic development projects in our service territory that demonstrate the latest energy and environmental building innovations and house several local college degree programs. In addition, we are making investments in emerging technology companies and venture capital funds.

The following table summarizes our actual and expected investments and capital expenditures at our other businesses as of and for the year ended December 31, 2021 (in thousands):

	Other
2021 Actual investments and capital expenditures	
Investments and capital expenditures (per the Consolidated Statement of Cash Flows)	$ 17,221
Expected total annual investments and capital expenditures (by year)	
2022	$ 15,000
2023	14,000
2024	10,000

These estimates of investments and capital expenditures are subject to continuing review and adjustment. Actual expenditures may vary from our estimates due to factors such as changes in business conditions or strategic plans.

See "Liquidity" for information regarding other material cash requirements for 2022 and thereafter.

Pension Plan

We contributed $42.0 million to the pension plan in 2021. We expect to contribute a total of $82.0 million to the pension plan in the period 2022 through 2026, with an annual contribution of $42.0 million for 2022 and $10.0 million from 2023 to 2026.

The final determination of pension plan contributions for future periods is subject to multiple variables, most of which are beyond our control, including changes to the fair value of pension plan assets, changes in actuarial assumptions (in particular the discount rate used in determining the benefit obligation), or changes in federal legislation. We may change our pension plan contributions in the future depending on changes to any variables, including those listed above.

See "Note 11 of the Notes to Consolidated Financial Statements" for additional information regarding the pension plan.

Credit Ratings

Our access to capital markets and our cost of capital are directly affected by our credit ratings. In addition, many of our contracts for the purchase and sale of energy commodities contain terms dependent upon our credit ratings. See "Enterprise Risk Management—Credit Risk Liquidity Considerations" and "Note 7 of the Notes to Consolidated Financial Statements."

The following table summarizes our credit ratings as of February 22, 2022:

	Standard & Poor's [1]	Moody's [2]
Corporate/Issuer rating	BBB	Baa2
Senior Secured Debt	A-	A3
Senior Unsecured Debt	BBB	Baa2

(1) Standard & Poor's lowest "investment grade" credit rating is BBB-.

(2) Moody's lowest "investment grade" credit rating is Baa3.

A security rating is not a recommendation to buy, sell or hold securities. Each security rating is subject to revision or withdrawal at any time by the assigning rating organization. Each security rating agency has its own methodology for assigning ratings, and, accordingly, each rating should be considered in the context of the applicable methodology, independent of all other ratings. The rating agencies provide ratings at the request of Avista Corp. and charge fees for their services.

Dividends

See "Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities" for a detailed discussion of our dividend policy and the factors which could limit the payment of dividends.

Competition

Our electric and natural gas distribution utility business has historically been recognized as a natural monopoly. In each regulatory jurisdiction, our rates for retail electric and natural gas services (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are generally determined on a "cost of service" basis. Rates are designed to provide, after recovery of allowable operating expenses and capital investments, an opportunity for us to earn a reasonable return on investment as allowed by our regulators.

In retail markets, we compete with various rural electric cooperatives and public utility districts in and adjacent to our service territories in the provision of service to new electric customers. We have entered into a number of service territory agreements with certain rural electric cooperatives and public utility districts, approved in applicable jurisdictions, to set forth conditions under which one or the other utility will provide service to customers. Alternative energy technologies, including customer-sited solar, wind or geothermal generation, or energy storage may also compete with us for sales to existing customers. Advances in power generation, energy efficiency, energy storage and other alternative energy technologies could lead to more wide-spread usage of these technologies, thereby reducing customer demand for the energy supplied by us. This reduction in usage and demand would reduce our revenue and negatively impact our financial condition including possibly leading to our inability to fully recover our investments in generation, transmission and distribution assets. Similarly, our natural gas distribution operations compete with other energy sources including heating oil, propane and other fuels.

Certain natural gas customers could bypass our natural gas system, reducing both revenues and recovery of fixed costs. To reduce the potential for such bypass, we price natural gas services, including transportation contracts, competitively and have varying degrees of flexibility to price transportation and delivery rates by means of individual contracts. These individual contracts are subject to state regulatory review and approval. We have long-term transportation contracts with several of our largest industrial customers under which the customer acquires its own commodity while using our infrastructure for delivery. Such contracts reduce the risk of these customers bypassing our system in the foreseeable future and minimizes the impact on our earnings.

Customers may have a choice in the future over the sources from which to receive their energy. In order to effectively compete for our customers in the future, we continue to strive to create value through product and service offerings. We are also attempting to enhance the effectiveness and ease of our customer interactions with us by tailoring our internal company initiatives to focus on choices for our customers to increase their overall satisfaction with the Company.

Also, non-utility businesses are developing new technologies and services to help energy consumers manage energy in new ways that may improve productivity and could alter demand for the energy we sell.

In wholesale markets, competition for available electric supply is influenced by the:

- localized and system-wide demand for energy,
- type, capacity, location and availability of generation resources, and
- variety and circumstances of market participants.

These wholesale markets are regulated by the FERC, which requires electric utilities to:

- transmit power and energy to or for wholesale purchasers and sellers,
- enlarge or construct additional transmission capacity for the purpose of providing these services, and
- transparently price and offer transmission services without favor to any party, including the merchant functions of the utility.

Participants in the wholesale energy markets include:

- other utilities,
- federal power marketing agencies,
- energy marketing and trading companies,
- independent power producers,
- financial institutions, and
- commodity brokers.

Economic Conditions and Utility Load Growth

The general economic data, on both national and local levels, contained in this section is based, in part, on independent government and industry publications, reports by market research firms or other independent sources. While we believe that these publications and other sources are reliable, we have not independently verified such data and can make no representation as to its accuracy.

Avista Utilities

We track multiple economic indicators affecting the three largest metropolitan statistical areas in our Avista Utilities service area: Spokane, Washington, Coeur d'Alene, Idaho, and Medford, Oregon. The key indicators are employment change and unemployment rates. On an annual basis, 2021 showed positive job growth with lower unemployment rates in all three metropolitan areas. This reflects the on-going recovery from the 2020 COVID-19 induced recession. The unemployment rates in Spokane and Medford are near the national average, while Coeur d'Alene is lower. Other leading indicators, such as initial unemployment claims and residential building permits, signal continued growth over the next 12 months. Considering all relevant indicators, we expect economic growth in our service area in 2022 to be in-line with the U.S. as a whole.

Reflecting the on-going recovery from the COVID-19 recession, nonfarm employment (seasonally adjusted) in our eastern Washington, northern Idaho and southwestern Oregon metropolitan service areas increased in 2021. In Spokane, Washington employment increased 3.8 percent with gains in all major sectors except manufacturing; information; financial activities; and government. Employment increased 5.3 percent in Coeur d'Alene, Idaho, reflecting gains in all major sectors except mining and logging; manufacturing; and government. In Medford, Oregon, employment increased 2.7 percent, with gains in all major sectors except information and government. U.S. nonfarm sector employment increased 2.7 percent over the same period.

Changes in the unemployment rate in 2021 reflect a gradual recovery from the COVID-19 recession. In Spokane the unemployment rate was 8.8 percent in 2020 and fell to 4.9 percent in 2021; in Coeur d'Alene the rate fell from 6.9 percent in 2020 to 3.6 percent in 2021; and in Medford the rate fell from 7.8 percent in 2020 to 5.3 percent in 2021. The U.S. unemployment rate fell from 8.1 percent in 2020 percent to 5.3 percent in 2021.

Alaska Electric Light and Power Company

Our AEL&P service area is centered in Juneau. Although Juneau is Alaska's state capital, it is not a metropolitan statistical area. This means breadth and frequency of economic data is more limited. Therefore, the dates of Juneau's economic data may significantly lag the period of this filing.

The Quarterly Census of Employment and Wages for Juneau shows employment increased 1.4 percent between the first half of 2020 and first half of 2021. There were employment gains in all major sectors, except trade, transportation, and utilities; information; financial activities; professional and business services; and other services. Government employment increased 2.3 percent during this period; this sector accounted for 41 percent of total employment in 2020. Between 2020 and 2021, the unemployment rate fell from 6.6 percent to 4.5 percent.

Forecasted Customer and Load Growth

Based on our forecast for 2022 through 2026 for Avista Utilities' service area, we expect annual electric customer growth to average 1.2 percent, within a forecast range of 0.8 percent to 1.6 percent. We expect annual natural gas customer growth to average 1.4 percent, within a forecast range of 0.8 percent to 2.0 percent. We anticipate retail electric load growth to average 0.6 percent, within a forecast range of 0.2 percent and 1.0 percent. We expect natural gas load growth to average 0.9 percent, within a forecast range of 0.4 percent and 1.4 percent. The forecast ranges reflect (1) the inherent uncertainty associated with the economic assumptions on which forecasts are based and (2) the historic variability of natural gas customer and load growth. These natural gas forecast ranges do not reflect the uncertainty regarding new natural gas laws or regulations that could be effective in future periods. See further discussion regarding these natural gas regulations as included in "Environmental Issues and Contingencies" below.

In AEL&P's service area, we expect no growth in residential, commercial and government customers for the period 2021 through 2024. We anticipate average annual total load growth will be in a narrow range around 0.5 percent, with residential load growth averaging 1.0 percent and no growth in commercial and government load. Residential load growth reflects (1) existing customers switching from diesel generated heat to electric heat pumps, and (2) an increase in the residential use of electric vehicles.

The forward-looking statements set forth above regarding retail load growth are based, in part, upon purchased economic forecasts and publicly available population and demographic studies. The expectations regarding retail load growth are also based upon various assumptions, including:

- assumptions relating to weather and economic and competitive conditions,
- internal analysis of company-specific data, such as energy consumption patterns,
- internal business plans,
- an assumption that we will incur no material loss of retail customers due to self-generation or retail wheeling, and
- an assumption that demand for electricity and natural gas as a fuel for mobility will for now be immaterial.

Changes in actual experience can vary significantly from our projections.

See also "Competition" above for a discussion of competitive factors that could affect our results of operations in the future.

Environmental Issues and Contingencies

We are subject to environmental regulation by federal, state and local authorities. The generation, transmission, distribution, service and storage facilities in which we have ownership interests or which we may need to acquire or develop are subject to environmental laws, regulations and rules relating to construction permitting, air emissions, water quality, fisheries, wildlife, endangered species, avian interactions, wastewater and stormwater discharges, waste handling, natural resource protection, historic and cultural resource protection, and other similar activities. These laws and regulations require the Company to make substantial investments in compliance activities and to acquire and comply with a wide variety of environmental licenses, permits, approvals and settlement agreements. These items are enforceable by public officials and private individuals. Some of these regulations are subject to ongoing interpretation, whether administratively or judicially, and are often in the process of being modified. We conduct periodic reviews and audits of pertinent facilities and operations to enhance compliance and to respond to or anticipate emerging environmental issues. The Company's Board of Directors has established a committee to oversee environmental issues and to assess and manage environmental risk.

We monitor legislative and regulatory developments at different levels of government for environmental issues, particularly those with the potential to impact the operation of our generating plants and other assets. We continue to be subject to increasingly stringent or expanded application of environmental and related regulations from all levels of government.

Environmental laws and regulations may restrict or impact our business activities in many ways, including, but not limited to, by:

- increasing the operating costs of generating plants and other assets,
- increasing the lead time and capital costs for the construction of new generating plants and other assets,
- requiring modification of our existing generating plants,
- requiring existing generating plant operations to be curtailed or shut down,
- reducing the amount of energy available from our generating plants,
- restricting the types of generating plants that can be built or contracted with,
- requiring construction of specific types of generation plants at higher cost, and
- increasing costs of distributing, or limiting our ability to distribute, electricity and/or natural gas.

Compliance with environmental laws and regulations could result in increases to capital expenditures and operating expenses. We intend to seek recovery of any such costs through the ratemaking process.

Washington Clean Energy Transformation Act (CETA)

In 2019, the Washington State Legislature passed the CETA, which requires Washington utilities to eliminate the costs and benefits associated with coal-fired resources from their retail electric sales by December 31, 2025. This requirement would effectively prohibit sales of energy produced by coal-fired generation to Washington retail customers after December 31, 2025. In addition, CETA establishes the policy of Washington State that all retail sales of electricity to Washington customers must be carbon-neutral by January 1, 2030 and requires that each electric utility demonstrate compliance with this standard by using electricity from renewable and other non-emitting resources for 100 percent of the utility's retail electric load over consecutive multi-year compliance periods; provided, however, that through December 31, 2044 the utility may satisfy up to 20 percent of this requirement with specified payments, credits and/or investments in qualifying energy transformation projects. The law has direct, specific impacts on Colstrip, which are unique to those owners of Colstrip who serve Washington customers. See "Colstrip" section and "Note 22 of the Notes to Consolidated Financial Statements" for further details on the impacts of CETA on Colstrip and our continued participation in Colstrip. Our hydroelectric and biomass generation facilities can be used to comply with the CETA's clean energy standards. We intend to seek recovery of any costs associated with the clean energy legislation and regulations through the regulatory process.

As required under CETA, in October 2021, we filed our first Clean Energy Implementation Plan (CEIP) with the WUTC. This filing triggered comments from interested parties in January 2022, with WUTC action to follow thereafter in 2022. We must file a CEIP with the WUTC every four years.

Our CEIP is a road map of specific actions we propose to take over the next four years (2022–2025) to show the progress being made toward clean energy goals and the equitable distribution of benefits and burdens to all customers as established by the CETA, which was passed by the Washington legislature and enacted into law in 2019. CETA requires electric supply to be greenhouse gas neutral by 2030 and 100 percent renewable or generated from zero-carbon resources by 2045.

Some highlights of our CEIP include:

- Beginning in 2022, we plan to serve 80 percent of our Washington customer demand with owned and purchased renewable energy, then increase this target by 5 percent every two years.
- To minimize rate impacts as we transition to cleaner energy, we are proposing to sell some of our renewable energy credits (RECs) on the open market through 2029. In 2030, we will utilize 100 percent of RECs on behalf of our customers, rather than selling RECs on the open market.
- The plan sets energy efficiency targets to reduce customer load by approximately 2 percent over the next four years by 204,305 megawatt hours through incentives and programs to lower energy use without impacting the customer.
- Our demand response target is to lower peak demand by 30 megawatts in periods of extreme heat or cold as an effort to eliminate the need for future resources.
- We have proposed a variety of initiatives to promote the equitable distribution of the benefits and burdens of renewable energy and are still working to find the best way to achieve these goals.

While the CEIP represents our current objectives, it is subject to change from time-to-time in the future as circumstances warrant including direct input from the WUTC.

Policies Related to Climate Change

Legal and policy changes responding to concerns about long-term global climate changes, and the potential impacts of such changes, could have a significant effect on our business. Our operations could be affected by changes in laws and regulations intended to mitigate the risk of, or alter, global climate changes, including restrictions on the operation of our power generation resources and obligations or limitations imposed on the sale of natural gas. Changing temperatures and precipitation, including snowpack conditions, affect the availability and timing of streamflows, which impact hydroelectric generation. Extreme weather events could increase fire risks, service interruptions, outages and maintenance costs. Changing temperatures could also change the magnitude and timing of customer demand.

Federal Regulatory Actions

In June 2019, the EPA released the final version of the Affordable Clean Energy (ACE) rule, the replacement for the Clean Power Plan (Federal CPP). The final ACE rule finalized the repeal of the Federal CPP and comprised the EPA's determination of the Best System of Emissions Reduction (BSER) for existing coal-fired power plants as heat rate efficiency improvements based on a range of "candidate technologies."

In January 2021, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) vacated the ACE Rule and remanded the record back to the EPA for further consideration consistent with its opinion, finding that the EPA misinterpreted the Clean Air Act when it determined that the language of Section 111 barred consideration of emissions reduction options that were not applied at the source. The Court also vacated the repeal of the Federal CPP. In February 2021, the EPA moved for a partial stay of the Court's mandate, noting that no Section 111(d) rule should go into effect until the EPA conducted new rulemaking in response to the January 2021 decision. The Court subsequently issued an order withholding issuance of the mandate with respect to the repeal of the Federal CPP and directing issuance of the mandate "in the normal course" for the vacatur of the replacement portion of the rule. In April 2021, numerous parties requested the Supreme Court's review of the D.C. Circuit's January 2021 decision, and in October 2021, the Supreme Court granted such review. Oral arguments are scheduled for February 2022 in this case.

Given the status of the EPA's rulemaking, we cannot reasonably predict the timing, outcome or applicability of these issues with respect to any of the Company's generation resources.

Washington Legislation and Regulatory Actions

Clean Air Rule

In September 2016, the Washington State Department of Ecology adopted the Clean Air Rule (CAR) to cap and reduce greenhouse gas (GHG) emissions across the State of Washington in pursuit of the State's GHG goals, which were enacted in 2008 by the Washington State Legislature. In response, the Company, Cascade Natural Gas Corporation, NW Natural and Puget Sound Energy jointly filed actions in both the Eastern District of Washington and in Thurston County Superior Court, challenging the CAR.

In January 2020, the Washington State Supreme Court issued a decision holding that the CAR was invalid as to non-emitters, such as natural gas distributors, but could be enforced against direct emitters, such as natural gas generation plants. The Court has remanded the matter to Thurston County Superior Court, where it has been stayed by the Court. At this time, we are continuing to evaluate the potential impact of the surviving portion of the rule, if any, to our generation facilities, should their emissions exceed the rule's compliance threshold. The rule is not intended to apply to the Kettle Falls Generating Station. We plan to seek recovery of any costs related to compliance with the surviving portion of the CAR through the ratemaking process.

Emissions Performance Standard

Washington also applies a GHG emissions performance standard to electric generation facilities used to serve retail loads in their jurisdictions, whether the facilities are located within its state or elsewhere. The emissions performance standard prevents utilities from constructing or purchasing generation facilities, or entering into power purchase agreements of five years or longer duration to purchase energy produced by plants that, in any case, have emission levels higher than 1,100 pounds of GHG per MWh. The Washington State Department of Commerce reviews the standard every five years. In September 2018, it adopted a new standard of 925 pounds of GHG per MWh. We intend to seek recovery of costs related to ongoing and new requirements through the ratemaking process.

Washington Climate Commitment Act

In 2021, the legislature passed the Climate Commitment Act, which establishes a cap and invest program to help achieve Washington's greenhouse gas limits by 2050. The Washington Department of Ecology is responsible for the implementation and the start of this program by January 1, 2023, including the adoption of annual allowance budgets for the first compliance period of the program by October 1, 2022. There are various rule making proceedings regarding the details of the program pending before the Department of Ecology. We will actively monitor and participate in these rulemakings as they proceed but cannot reasonably predict how these programs may impact our facilities at this time.

Oregon Legislation and Regulatory Actions

Climate Protection Plan

In March 2020, Oregon Governor Kate Brown issued Executive Order No. 20-04, "Directing State Agencies to Take Actions to Reduce and Regulate Greenhouse Gas Emissions." The Executive Order launched rulemaking proceedings for every Oregon agency with jurisdiction over greenhouse gas-related matters, with the aim of reducing Oregon's overall GHG emissions to 80 percent below 1990 levels by 2050. Oregon agencies, including the Oregon Department of Environmental Quality (ODEQ) and the OPUC, issued reports discussing general intent to carry out the Executive Order.

The ODEQ subsequently developed cap and reduce rules known as the Climate Protection Program (Oregon CPP). Final rules were adopted by the Environmental Quality Commission (EQC) in December 2021 and become effective in 2022. The Oregon CPP originally proposed emission reduction targets of at least 45 percent below 1990 levels by 2035 and at least 80 percent below 1990 levels by 2050, in accordance with Executive Order 20-04. However, during the December 2021 ODEQ presentation to the EQC, substantial changes were made to the final version of the Oregon CPP, as compared to the version of the Oregon CPP that was open for public comment. One of the most significant items revises the emissions cap and mandates emissions reductions of at least 50 percent by 2035 and 90 percent by 2050. We are evaluating the potential impacts of these regulations. Compliance efforts to meet the Oregon CPP emissions reduction goals could materially impact our Oregon natural gas business.

The OPUC has opened a Natural Gas Fact-Finding effort to analyze the potential natural gas utility bill impacts that may result from limiting GHG emissions of regulated natural gas utilities under the ODEQ's Oregon CPP and to identify appropriate regulatory tools to mitigate potential customer impacts. According to the OPUC Staff, the ultimate goal of the Fact-Finding Docket will be to inform future policy decisions and other key analyses to be considered in 2022. We expect the OPUC Staff will present a final report on the Fact-Finding effort to the OPUC in late spring of 2022 with recommendations for further OPUC engagement later in 2022.

Emissions Performance Standard

Like Washington, Oregon applies a GHG emissions performance standard to electric generation facilities, requiring that any new baseload natural gas plant, non-base load natural gas plant, and non-generating facility reduce its net carbon dioxide emissions 17 percent below the most efficient combustion-turbine plant in the United States. The Oregon Energy Facility Siting Council issues rules periodically to update the standard, as more efficient power plants are built in other states. The standard can be met by any combination of efficiency, cogeneration, and offsets from carbon dioxide mitigation measures. We have thermal generation located in Oregon, and as such this standard applies to that facility. We intend to seek recovery of costs related to ongoing and new requirements through the ratemaking process.

Clean Electricity and Coal Transition Act

In Oregon, legislation was enacted in 2016 which requires Portland General Electric and PacifiCorp to remove coal-fired generation from their Oregon rate base by 2030. This legislation does not directly relate to Avista Corp. because Avista Corp. is not an electric utility in Oregon. However, because these two utilities, along with Avista Corp., hold minority interests in Colstrip, the legislation could indirectly impact Avista Corp., though specific impacts cannot be reasonably predicted at this time. While the legislation requires Portland General Electric and PacifiCorp to eliminate Colstrip from their rates, they would be permitted to sell the output of their shares of Colstrip into the wholesale market or, as is the case with PacifiCorp, reallocate generation from Colstrip to other states. We cannot predict the eventual outcome of actions arising from this legislation at this time or estimate the effect thereof on Avista Corp.; however, we intend to continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to our generation assets.

Clean Air Act (CAA)

The CAA creates numerous requirements for our thermal generating plants. Colstrip, Kettle Falls GS, Coyote Springs and Rathdrum CT all require CAA Title V operating permits. The Boulder Park GS, Northeast CT and a number of other operations require minor source permits or simple source registration permits. We have secured these permits and certify our compliance with Title V permits on an annual basis. These requirements can change over time as the CAA or applicable implementing regulations are amended and new permits are issued. We actively monitor legislative, regulatory and other program developments of the CAA that may impact our facilities.

Threatened and Endangered Species and Wildlife

A number of species of fish in the Northwest are listed as threatened or endangered under the Federal Endangered Species Act. We are implementing fish protection measures at our hydroelectric project on the Clark Fork River under a 45-year FERC operating license for Cabinet Gorge and Noxon Rapids (issued in 2001) that incorporates a comprehensive settlement agreement. The restoration of native salmonid fish, including bull trout, a threatened species, is a key part of the agreement. The result is a collaborative native salmonid restoration program with the U.S. Fish and Wildlife Service, Native American tribes and the states of Idaho and Montana on the lower Clark Fork River, consistent with requirements of the FERC license. Recent efforts in this program include the development of a permanent fish passage facility at Cabinet Gorge dam, as well as fish capture facilities on tributaries to the Clark Fork River. The U.S. Fish & Wildlife Service issued an updated Critical Habitat Designation for bull trout in 2010 that includes the lower Clark Fork River, as well as portions of the Coeur d'Alene basin within our Spokane River Project area, and issued a final Bull Trout Recovery Plan under the ESA. Regional efforts are underway evaluating the potential of re-establishing anadromous fish above previously blocked areas, including the Spokane River, which is upstream from Grand Coulee dam.

Various statutory authorities, including the Migratory Bird Treaty Act, have established penalties for the unauthorized take of migratory birds. Because we operate facilities that can pose risks to a variety of such birds, we have developed and follow an avian protection plan.

We are also aware of other threatened and endangered species and issues related to them that could be impacted by our operations and we make every effort to comply with all laws and regulations relating to these threatened and endangered species. We expect costs associated with these compliance efforts to be recovered through the ratemaking process.

Cabinet Gorge Total Dissolved Gas Abatement Plan

Dissolved atmospheric gas levels (referred to as "Total Dissolved Gas" or "TDG") in the Clark Fork River exceed state of Idaho and federal water quality numeric standards downstream of Cabinet Gorge particularly during periods when excess river flows must be diverted over the spillway. Under the terms of the Clark Fork Settlement Agreement as incorporated in the FERC license for the Clark Fork Project, we work in consultation with agencies, tribes and other stakeholders to address this issue through structural modifications to the spillgates, monitoring and analysis. After extensive testing, Clark Fork Settlement Agreement stakeholders have agreed that no further spillway modifications are justified. For the remainder of the FERC License term, we will continue to mitigate remaining impacts of TDG while periodically considering the potential for new approaches to further reduce TDG. We continue to work with stakeholders to determine the degree to which TDG abatement impacts future mitigation obligations. We have sought, and intends to continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

Other

For other environmental issues and other contingencies see "Note 22 of the Notes to Consolidated Financial Statements."

Colstrip

Colstrip is a coal-fired generating plant in southeastern Montana that includes four units and which is owned by six separate entities. We have a 15 percent ownership interest in Units 3 & 4. The other owners are Puget Sound Energy, Inc., Portland General Electric Company, NorthWestern Corporation, Pacificorp and Talen Montana, LLC (which is also the operator of the plant). In January 2020, the owners of Units 1 & 2, in which the Company has no ownership, closed those two units. The owners of Units 3 & 4 currently share operating and capital costs pursuant to the terms of an operating agreement among them (the Ownership and Operation Agreement).

Depreciation of Colstrip Assets

We received orders from the IPUC and WUTC allowing us to accelerate the depreciation of our 15 percent ownership interest in Colstrip to 2027 for Idaho and 2025 for Washington.

Coal Ash Management/Disposal

In 2015, the EPA issued a final rule regarding coal combustion residuals (CCRs), also termed coal combustion byproducts or coal ash (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. In December 2019, a proposed revision to the rule was published in the Federal Register to address the D.C. Circuit's decision. The rule includes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act, the nation's primary law for regulating solid waste.

The Colstrip owners developed a multi-year compliance plan to address the CCR requirements along with existing state obligations expressed through the 2012 Administrative Order on Consent (AOC) with Montana Department of Environmental Quality (MDEQ). These requirements continue despite the 2018 federal court ruling.

The AOC requires MDEQ to review Remedy and Closure plans for all parts of the Colstrip plant through an ongoing public process. The AOC also requires the Colstrip owners 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 obligations. We are responsible for our share of two major areas: the Plant Site Area and the Effluent Holding Pond Area. Generally, the plans include the removal of Boron, Chloride, and Sulfate from the groundwater, closure of the existing ash storage ponds, and installation of a new water treatment system to convert the facility to a dry ash storage. We recently adjusted our share of the posted surety bonds to $17.3 million. This amount will be updated annually, with expected obligations decreasing over time as remediation activities are completed.

Colstrip Coal Contract

Colstrip is supplied with fuel from adjacent coal reserves under coal supply and transportation agreements. Several of the co-owners of Colstrip, including us, have a coal contract that runs through December 31, 2025.

Colstrip Arbitration, Litigation, and Other Contingencies

See "Note 22 of the Notes to Consolidated Financial Statements" for disputes, arbitration, litigations and other contingencies related to Colstrip. We continue to assess the best options for Colstrip in conjunction with our co-owners. We intend to seek recovery of any costs associated with Colstrip through the ratemaking process.

Enterprise Risk Management

The material risks to our businesses are discussed in "Item 1A. Risk Factors," "Forward-Looking Statements," as well as "Environmental Issues and Contingencies." The following discussion focuses on our mitigation processes and procedures to address these risks.

We consider the management of these risks an integral part of managing our core businesses and a key element of our approach to corporate governance.

Risk management includes identifying and measuring various forms of risk that may affect the Company. We have an enterprise risk management process for managing risks throughout our organization. Our Board of Directors and its Committees take an active role in the oversight of risk affecting the Company. Our risk management department facilitates the collection of risk information across the Company, providing senior management with a consolidated view of the Company's major risks and risk mitigation measures. Each area identifies risks and implements the related mitigation measures. The enterprise risk process supports management in identifying, assessing, quantifying, managing and mitigating the risks. Despite all risk mitigation measures, however, risks are not eliminated.

Our primary identified categories of risk exposure are:

- Utility regulatory
- Operational
- Climate change
- Cyber and technology
- Strategic
- External mandates
- Financial
- Energy commodity
- Compliance

Our primary categories of risks are described in "Item 1A. Risk Factors."

Utility Regulatory Risk

Regulatory risk is mitigated through a separate regulatory group which communicates with commission regulators and staff regarding the Company's business plans and concerns. The regulatory group also considers the regulator's priorities and rate policies and makes recommendations to senior management on regulatory strategy for the Company. Oversight of our regulatory strategies and policies is performed by senior management and our Board of Directors. See "Regulatory Matters" for further discussion of regulatory matters affecting our Company.

Operational Risk

To manage operational and event risks, we maintain emergency operating plans, business continuity and disaster recovery plans, maintain insurance coverage against some, but not all, potential losses and seek to negotiate indemnification arrangements with contractors for certain event risks. In addition, we design and follow detailed vegetation management and asset management inspection plans, which help mitigate wildfire and storm event risks, as well as identify utility assets which may be failing and in need of repair or replacement. We also have an Emergency Operating Center, which is a team of employees that plan for and train to deal with potential emergencies or unplanned outages at our facilities, resulting from natural disasters or other events. To prevent unauthorized access to our facilities, we have both physical and cyber security in place.

To address the risk related to fuel cost, availability and delivery restraints, we have an energy resources risk policy, which includes our wholesale energy markets credit policy and control procedures to manage energy commodity price and credit risks. Development of the energy resources risk policy includes planning for sufficient capacity to meet our customer and wholesale energy delivery obligations. See further discussion of the energy resources risk policy below.

Oversight of the operational risk management process is performed by the Environmental, Technology and Operations Committee of our Board of Directors and from senior management with input from each operating department.

Climate Change Risk

Multiple departments at the Company work to mitigate risks related to climate change. Climate change adds uncertainty to existing risks that we have historically managed and mitigated. These efforts are reflected in electric and gas operations, investments in assets and asset reliability and resiliency across the Company's operations, and in more specific efforts, such as the Wildfire Resiliency Plan. Power Supply staff, as a regular course of business, monitor items such as snowpack and broader precipitation conditions, patterns and modeled or predicted climate change. These and other assessments are incorporated into our IRP processes. Environmental Affairs, Governmental Affairs and other departments monitor policy and regulatory developments that may relate to climate change in order to engage these efforts constructively and prepare for compliance matters.

The Company has created four councils that are centered around its primary focus areas: our customers, our people, performance and invention. The Perform Council is an interdisciplinary team of management and other employees of the Company which regularly meets to discuss, assess and manage current issues associated with the Company's performance. A key area of focus for the Perform Council is potential risks and opportunities associated with long-term global climate change. Among other things, the Perform Council:

- facilitates internal and external communications regarding climate change and related issues,
- analyzes policy effects, anticipates opportunities and evaluates strategies for the Company,
- develops recommendations on climate related policy positions and action plans, and
- provides direction and oversight with respect to the Company's clean energy goals.

In addition, issues concerning climate-related risk and the Company's clean energy goals are reviewed and regularly discussed by the Board of Directors. The Board's Environmental, Technology and Operations Committee regularly reviews and discusses environmental and climate related risks, and advises the full Board on any critical or emerging risks and/or related policies. Likewise, the Audit Committee provides oversight of the Company's climate-related disclosures.

Cyber and Technology Risk

We mitigate cyber and technology risk through trainings and exercises at all levels of the Company. The Environmental, Technology and Operations Committee of our Board of Directors along with senior management are regularly briefed on security policy, programs and incidents. Annual cyber and physical training and testing of employees are included in our enterprise security program. Our enterprise business continuity program facilitates business impact analysis of core functions for development of emergency operating plans, and coordinates annual testing and training exercises.

Technology governance is led by senior management, which includes new technology strategy, risk planning and major project planning and approval. The technology project management office and enterprise capital planning group provide project cost, timeline and schedule oversight. In addition, there are independent third party audits of our critical infrastructure security program and our business risk security controls.

We have a Technology department dedicated to securing, maintaining, evaluating and developing our information technology systems. There are regular training sessions for the technology and security team. This group also evaluates the Company's technology for obsolescence and makes recommendations for upgrading or replacing systems as necessary. Additionally, this group monitors for intrusion and security events that may include a data breach or attack on our operations.

Strategic Risk

Oversight of our strategic risk is performed by the Board of Directors and senior management. We have a Chief Strategy Officer who leads strategic initiatives, to search for and evaluate opportunities for the Company and makes recommendations to senior management. We not only focus on whether opportunities are financially viable, but also consider whether these opportunities fall within our core policies and our core business strategies. We mitigate our reputational risk primarily through a focus on adherence to our core policies, including our Code of Conduct, maintaining an appropriate Company culture and tone at the top, and through communication and engagement with our external stakeholders.

External Mandates Risk

Oversight of our external mandate risk mitigation strategies is performed by the Environmental, Technology and Operations Committee of our Board of Directors and senior management. We have a Perform Council which meets internally to assess the potential impacts of climate policy to our business and to identify strategies to plan for change. Our ESG program creates a framework that is intended to attract investment, enhancement of our brand, and promotion of sustainable long-term growth. We also have employees dedicated to actively engage and monitor federal, state and local government positions and legislative actions that may affect us or our customers.

To prevent the threat of municipalization, we work to build strong relationships with the communities we serve through, among other things:

- communication and involvement with local business leaders and community organizations,
- providing customers with a multitude of limited income initiatives, including energy fairs, senior outreach, low income workshops, mobile outreach strategy and a Low Income Rate Assistance Plan,
- tailoring our internal company initiatives to focus on choices for our customers, to increase their overall satisfaction with the Company, and
- engaging in the legislative process in a manner that fosters the interests of our customers and the communities we serve.

Financial Risk

Our financial risk is impacted by many factors. Several of these risks include regulation and rates, weather, access to capital markets, interest rate risk, credit risk, and foreign exchange risk. We have a Treasury department that monitors our daily cash position and future cash flow needs, as well as monitoring market conditions to determine the appropriate course of action for capital financing and/or hedging strategies. Oversight of our financial risk mitigation strategies is performed by senior management and the Finance Committee of our Board of Directors.

Regulation and Rates

Our Regulatory department is critical in mitigation of financial risk as they have regular communications with state commission regulators and staff and they monitor and develop rate strategies for the Company. Rate strategies, such as decoupling, help mitigate the impacts of revenue fluctuations due to weather, conservation or the economy.

Weather Risk

To partially mitigate the risk of financial under-performance due to weather-related factors, we developed decoupling rate mechanisms that were approved by the Washington, Idaho and Oregon commissions. Decoupling mechanisms are designed to break the link between a utility's revenues and consumers' energy usage and instead provide revenue based on the number of customers, thus mitigating a large portion of the risk associated with lower customer loads. See "Regulatory Matters" for further discussion of our decoupling mechanisms.

Access to Capital Markets

Our capital requirements rely to a significant degree on regular access to capital markets. We actively engage with rating agencies, banks, investors and state public utility commissions to understand and address the factors that support access to capital markets on reasonable terms. We manage our capital structure to maintain a financial risk profile that we believe these parties will deem prudent. We forecast cash requirements to determine liquidity needs, including sources and variability of cash flows that may arise from our spending plans or from external forces, such as changes in energy prices or interest rates. Our financial and operating forecasts consider various metrics that affect credit ratings. Our regulatory strategies include working with state public utility commissions and filing for rate changes as appropriate to meet financial performance expectations.

Interest Rate Risk

Uncertainty about future interest rates causes risk related to a portion of our existing debt, our future borrowing requirements, and our pension and other postretirement benefit obligations. We manage debt interest rate exposure by limiting our variable rate debt to a percentage of total capitalization of the Company. We hedge a portion of our interest rate risk on forecasted debt issuances with financial derivative instruments. The Finance Committee of our Board of Directors periodically reviews and discusses interest rate risk management processes and the steps management has undertaken to control interest rate risk. Our Risk Management Committee (RMC) also reviews our interest rate risk management plan. Additionally, interest rate risk is managed by monitoring market conditions when timing the issuance of long-term debt and optional debt redemptions and establishing fixed rate long-term debt with varying maturities.

Our interest rate swap derivatives are considered economic hedges against the future forecasted interest rate payments of our long-term debt. Interest rates on our long-term debt are generally set based on underlying U.S. Treasury rates plus credit spreads, which are based on our credit ratings and prevailing market prices for debt. The interest rate swap derivatives hedge against changes in the U.S. Treasury rates but do not hedge the credit spread.

Even though we work to manage our exposure to interest rate risk by locking in certain long-term interest rates through interest rate swap derivatives, if market interest rates decrease below the interest rates we have locked in, this will result in a liability related to our interest rate swap derivatives, which can be significant. However, through our regulatory accounting practices similar to our energy commodity derivatives, any interim mark-to-market gains or losses are offset by regulatory assets and liabilities. Upon settlement of interest rate swap derivatives, the cash payments made or received are recorded as a regulatory asset or liability and are subsequently amortized as a component of interest expense over the life of the associated debt. The settled interest rate swap derivatives are also included as a part of Avista Corp.'s cost of debt calculation for ratemaking purposes.

The following table summarizes our interest rate swap derivatives outstanding as of December 31, 2021 and December 31, 2020 (dollars in thousands):

	2021	2020
Number of agreements	16	16
Notional amount	$ 170,000	$ 175,000
Mandatory cash settlement dates	2022 to 2024	2021 to 2023
Long-term derivative assets (1)	$ 1,149	$ —
Short-term derivative liability (1) (2)	(24,026)	(11,525)
Long-term derivative liability (1) (2)	(78)	(31,238)

(1) *There are offsetting regulatory assets and liabilities for these items on the Consolidated Balance Sheets in accordance with regulatory accounting practices.*

(2) *The balance as of December 31, 2020 reflects the offsetting of $8.1 million, of cash collateral against the net derivative positions where a legal right of offset exists. There is no offsetting cash collateral in the 2021 balances.*

We estimate that a 10 basis point increase in forward LIBOR interest rates as of December 31, 2021 would increase the interest rate swap derivative net liability by $5.3 million, while a 10 basis point decrease would decrease the interest rate swap derivative net liability by $5.4 million.

We estimated that a 10 basis point increase in forward LIBOR interest rates as of December 31, 2020 would have increased the interest rate swap derivative net liability by $5.9 million, while a 10 basis point decrease would decrease the interest rate swap derivative net liability by $6.1 million.

The interest rate on $51.5 million of long-term debt to affiliated trusts is adjusted quarterly, reflecting current market rates. Amounts borrowed under our committed line of credit agreements have variable interest rates.

The following table shows our long-term debt (including current portion) and related weighted-average interest rates, by expected maturity dates as of December 31, 2021 (dollars in thousands):

	2022	2023	2024	2025	2026	Thereafter	Total	Fair Value
Fixed rate long-term debt (1)	$ 250,000	$ 13,500	$ 15,000	$ —	$ —	$ 1,885,000	$ 2,163,500	$ 2,524,270
Weighted-average interest rate	5.13%	7.35%	3.44%	—	—	4.25%	4.37%	
Variable rate long-term debt to affiliated trusts	—	—	—	—	—	$ 51,547	$ 51,547	$ 43,299
Weighted-average interest rate	—	—	—	—	—	1.05%	1.05%	

(1) These balances include the fixed rate long-term debt of Avista Corp., AEL&P and AERC.

Our pension plan is exposed to interest rate risk because the value of pension obligations and other postretirement obligations varies directly with changes in the discount rates, which are derived from end-of-year market interest rates. In addition, the value of pension investments and potential income on pension investments is partially affected by interest rates because a portion of pension investments are in fixed income securities. Oversight of our pension plan investment strategies is performed by the Finance Committee of the Board of Directors, which approves investment and funding policies, objectives and strategies that seek an appropriate return for the pension plan. We manage interest rate risk associated with our pension and other postretirement benefit plans by investing a targeted amount of pension plan assets in fixed income investments that have maturities with similar profiles to future projected benefit obligations. See "Note 11 of the Notes to Consolidated Financial Statements" for further discussion of our investment policy associated with the pension plan assets.

Credit Risk

Counterparty Non-Performance Risk

Counterparty non-performance risk relates to potential losses that we would incur as a result of non-performance of contractual obligations by counterparties to deliver energy or make financial settlements.

Changes in market prices may dramatically alter the size of credit risk with counterparties, even when we establish conservative credit limits. Should a counterparty fail to perform, we may be required to honor the underlying commitment or to replace existing contracts with contracts at then-current market prices.

We enter into bilateral transactions with various counterparties. We also trade energy and related derivative instruments through clearinghouse exchanges.

We seek to mitigate credit risk by:

- transacting through clearinghouse exchanges,
- entering into bilateral contracts that specify credit terms and protections against default,
- applying credit limits and duration criteria to existing and prospective counterparties,
- actively monitoring current credit exposures,
- asserting our collateral rights with counterparties, and
- carrying out transaction settlements timely and effectively.

The extent of transactions conducted through exchanges has increased, as many market participants have shown a preference toward exchange trading and have reduced bilateral transactions. We actively monitor the collateral required by such exchanges to effectively manage our capital requirements.

Counterparties' credit exposure to us is dynamic in normal markets and may change significantly in more volatile markets. The amount of potential default risk to us from each counterparty depends on the extent of forward contracts, unsettled transactions, interest rates and market prices. There is a risk that we do not obtain sufficient additional collateral from counterparties that are unable or unwilling to provide it.

Credit Risk Liquidity Considerations

To address the impact on our operations of energy market price volatility, our hedging practices for electricity (including fuel for generation) and natural gas extend beyond the current operating year. Executing this extended hedging program may increase credit risk and demands for collateral. Our credit risk management process is designed to mitigate such credit risks through limit setting, contract protections and counterparty diversification, among other practices.

Credit risk affects demands on our capital. We are subject to limits and credit terms that counterparties may assert to allow us to enter into transactions with them and maintain acceptable credit exposures. Many of our counterparties allow unsecured credit at limits prescribed by agreements or their discretion. Capital requirements for certain transaction types involve a combination of initial margin and market value margins without any unsecured credit threshold. Counterparties may seek assurances of performance from us in the form of letters of credit, prepayment or cash deposits.

Credit exposure can change significantly in periods of commodity price and interest rate volatility. As a result, sudden and significant demands may be made against our credit facilities and cash. We actively monitor the exposure to possible collateral calls and take steps to minimize capital requirements.

As of December 31, 2021, we had cash deposited as collateral of $30.6 million and letters of credit of $34.0 million outstanding related to our energy contracts. Price movements and/or a downgrade in our credit ratings could impact further the amount of collateral required. See "Credit Ratings" for further information.

For example, in addition to limiting our ability to conduct transactions, if our credit ratings were lowered to below "investment grade" based on our positions outstanding at December 31, 2021 (including contracts that are considered derivatives and those that are considered non-derivatives), we would potentially be required to post the following additional collateral (in thousands):

		2021
Additional collateral taking into account contractual thresholds	$	7,983
Additional collateral without contractual thresholds		9,194

Under the terms of interest rate swap derivatives that we enter into periodically, we may be required to post cash or letters of credit as collateral depending on fluctuations in the fair value of the instrument. As of December 31, 2021, we had interest rate swap agreements outstanding with a notional amount totaling $170.0 million and we had deposited no cash as collateral for these interest rate swap derivatives.

If our credit ratings were lowered to below "investment grade" based on our interest rate swap derivatives outstanding at December 31, 2021, we would potentially be required to post the following additional collateral (in thousands):

		2021
Additional collateral taking into account contractual thresholds (1)	$	11,730
Additional collateral without contractual thresholds		25,273

(1) This amount is different from the amount disclosed in "Note 7 of the Notes to Consolidated Financial Statements" because, while this analysis includes contracts that are not considered derivatives in addition to the contracts considered in Note 7, this analysis also takes into account contractual threshold limits that are not considered in Note 7.

Foreign Currency Risk

A significant portion of our utility natural gas supply (including fuel for electric generation) is obtained from Canadian sources. Most of those transactions are executed in U.S. dollars, which avoids foreign currency risk. A portion of our 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 typically settled within sixty days with U.S. dollars. We hedge a portion of the foreign currency risk by purchasing Canadian currency exchange derivatives when such commodity transactions are initiated. This risk has not had a material effect on our 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.

Further information for derivatives and fair values is disclosed at "Note 7 of the Notes to Consolidated Financial Statements" and "Note 18 of the Notes to Consolidated Financial Statements."

Energy Commodity Risk

We mitigate energy commodity risk primarily through our energy resources risk policy, which includes oversight from the RMC and oversight from the Audit Committee and the Environmental, Technology and Operations Committee of our Board of Directors. In conjunction with the oversight committees, our management team develops hedging strategies, detailed resource procurement plans, resource optimization strategies and long-term integrated resource planning to mitigate some of the risk associated with energy commodities. The various plans and strategies are monitored daily and developed with quantitative methods.

Our energy resources risk policy includes our wholesale energy markets credit policy and control procedures to manage energy commodity price and credit risks. Nonetheless, adverse changes in commodity prices, generating capacity, customer loads, regulation and other factors may result in losses of earnings, cash flows and/or fair values.

We measure the volume of monthly, quarterly and annual energy imbalances between projected power loads and resources. The measurement process is based on expected loads at fixed prices (including those subject to retail rates) and expected resources to the extent that costs are essentially fixed by virtue of known fuel supply costs or projected hydroelectric conditions. To the extent that expected costs are not fixed, either because of volume mismatches between loads and resources or because fuel cost is not locked in through fixed price contracts or derivative instruments, our risk policy guides the process to manage this open forward position over a period of time. Normal operations result in seasonal mismatches between power loads and available resources. We are able to vary the operation of generating resources to match parts of intra-hour, hourly, daily and weekly load fluctuations. We use the wholesale power markets, including the natural gas market as it relates to power generation fuel, to sell projected resource surpluses and obtain resources when deficits are projected. We buy and sell fuel for thermal generation facilities based on comparative power market prices and marginal costs of fueling and operating available generating facilities and the relative economics of substitute market purchases for generating plant operation.

To address the impact on our operations of energy market price volatility, our hedging practices for electricity (including fuel for generation) and natural gas extend beyond the current operating year. Executing this extended hedging program may increase our credit risks. Our credit risk management process is designed to mitigate such credit risks through limit setting, contract protections and counterparty diversification, among other practices.

Our projected retail natural gas loads and resources are regularly reviewed by operating management and the RMC. To manage the impacts of volatile natural gas prices, we seek to procure natural gas through a diversified mix of spot market purchases and forward fixed price purchases from various supply basins and time periods. We have an active hedging program that extends into future years with the goal of reducing price volatility in our natural gas supply costs. We use natural gas storage capacity to support high demand periods and to procure natural gas when price spreads are favorable. Securing prices throughout the year and even into subsequent years mitigates potential adverse impacts of significant purchase requirements in a volatile price environment.

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2021 that are expected to settle in each respective year (dollars in thousands). There are no expected deliveries of energy commodity derivatives after 2025:

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)
2022	(269)	—	(260)	6,198	650	1,572	(3,479)	(16,859)
2023	—	—	(54)	1,964	—	—	(1,612)	(757)
2024	—	—	(34)	296	—	—	(1,603)	5
2025	—	—	—	—	—	—	(1,146)	—

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2020 that were expected to settle in each respective year (dollars in thousands). There were no expected deliveries of energy commodity derivatives after 2025:

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)
2021	$ 2	$ (414)	$ (87)	$ 10,549	$ (15)	$ 716	$ (2,152)	$ (10,672)
2022	—	—	247	1,920	—	—	(1,697)	(1,536)
2023	—	—	—	(122)	—	—	(1,599)	(42)
2024	—	—	—	—	—	—	(1,673)	—
2025	—	—	—	—	—	—	(1,219)	—

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

The above electric and natural gas derivative contracts will be included in either power supply costs or natural gas supply costs during the period they are 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 eventually be collected through retail rates from customers.

See "Item 1. Business—Electric Operations" and "Item 1. Business—Natural Gas Operations," for additional discussion of the risks associated with Energy Commodities.

Compliance Risk

Compliance risk is mitigated through separate Regulatory and Environmental Compliance departments that monitor legislation, regulatory orders and actions to determine the overall potential impact to our Company and develop strategies for complying with the various rules and regulations. We also engage outside attorneys and consultants, when necessary, to help ensure compliance with laws and regulations. Oversight of our compliance risk strategy is performed by senior management, including our Chief Compliance Officer, and the Environmental, Technology and Operations Committee and the Audit Committee of our Board of Directors.

See "Item 1. Business, Regulatory Issues" through "Item 1. Business, Reliability Standards" and "Environmental Issues and Contingencies" for further discussion of compliance issues that impact our Company.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The information required by this item is set forth in the Enterprise Risk Management section of "Item 7. Management's Discussion and Analysis" and is incorporated herein by reference.

Item 8. Financial Statements and Supplementary Data

The Report of Independent Registered Public Accounting Firm and Financial Statements begin on the next page.

Report of Independent Registered Public Accounting Firm

To the shareholders and the Board of Directors of
Avista Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Avista Corporation and subsidiaries (the "Company") as of December 31, 2021 and 2020, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2021, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 22, 2022, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Matters—Refer to Notes 1, 22, and 23 to the financial statements

Critical Audit Matter Description

The Company accounts for its regulated operations in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 980, Regulated Operations ("ASC 980"). The provisions of this accounting guidance require, among other things, that financial statements of a rate-regulated enterprise reflect the actions of regulators, where appropriate. These actions may result in the recognition of revenues and expenses in time periods that are different than non-rate-regulated enterprises. When this occurs, costs are deferred as assets in the balance sheet (regulatory assets) and recorded as expenses when those amounts are reflected in rates. Also, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for recovery of costs that are expected to be incurred in the future (regulatory liabilities).

The Company is subject to regulation by the Washington Utilities and Transportation Commission, the Idaho Public Utilities Commission, the Public Utility Commission of Oregon, the Public Service Commission of the State of Montana and the Regulatory Commission of Alaska (collectively, the "Commissions"), which have jurisdiction with respect to, among other things, the rates of electric and natural gas distribution companies in Washington, Idaho, Oregon, Montana, and Alaska, respectively. Accounting for the economics of rate regulation has an impact on multiple financial statement line items and disclosures, such as property, plant, and equipment, regulatory assets and liabilities, operating revenues, operation and maintenance expense, and depreciation expense.

The Company's rates are subject to the rate-setting processes of the Commissions and, in certain jurisdictions, annual earnings oversight. Rates are determined and approved in regulatory proceedings based on analyses of the Company's costs to provide utility service and are designed to recover the Company's prudently incurred investments in the utility business and provide a return thereon. Decisions to be made by the Commissions in the future will impact the accounting for regulated operations under ASC 980 as described above. While the Company has indicated that it expects to recover costs from customers through regulated rates, there is a risk that the Commissions will not approve (1) full recovery of the costs of providing utility service or (2) full recovery of all amounts invested in the utility business and a reasonable return on that investment.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of part of the cost of recently completed plant or plant under construction and (3) refunds to customers. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following procedures, among others:

- We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs incurred as property, plant, and equipment and deferred as regulatory assets and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management's controls over the initial recognition of amounts as property, plant and equipment; regulatory assets or liabilities; and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the Commissions for the Company and other public utilities in the Company's jurisdictions, regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on the precedents of the Commissions' treatment of similar costs under similar circumstances. We evaluated the external information and compared it to management's recorded regulatory asset and liability balances for completeness.
- We inspected the Company's filings with the Commissions and the filings with the Commissions by intervenors that may impact the Company's future rates, evaluating the evidence in relation to management's assertions, as applicable.
- We inquired of management about property, plant, and equipment that may be abandoned. We inspected the capital-projects budget and construction-work-in-process listings and inquired of management to identify projects that are designed to replace assets that may be retired prior to the end of their useful life. We inspected minutes of the Board of Directors and regulatory orders and other filings with the Commissions, evaluating the evidence in relation to management's assertions, as applicable, regarding probability of an abandonment.
- We obtained an analysis from management regarding probability of recovery for regulatory assets or probability of either refund or future reduction in rates for regulatory liabilities not yet addressed in a regulatory order in order to assess management's assertion that amounts are probable of recovery and/or that a future refund or reduction in rates is not probable.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 22, 2022

We have served as the Company's auditor since 1933.

Consolidated Statements of Income

Avista Corporation

For the Years Ended December 31,

Dollars in thousands, except per share amounts

	2021	2020	2019
Operating Revenues:			
Utility revenues:			
Utility revenues, exclusive of alternative revenue programs	$ 1,445,000	$ 1,324,091	$ 1,323,524
Alternative revenue programs	(6,635)	(3,814)	9,614
Total utility revenues	1,438,365	1,320,277	1,333,138
Non-utility revenues	571	1,614	12,484
Total operating revenues	1,438,936	1,321,891	1,345,622
Operating Expenses:			
Utility operating expenses:			
Resource costs	497,123	398,509	439,817
Other operating expenses	366,125	354,614	345,212
Merger transaction costs	—	—	19,675
Depreciation and amortization	231,915	223,507	205,365
Taxes other than income taxes	109,353	106,501	105,652
Non-utility operating expenses:			
Other operating expenses	5,927	5,344	18,883
Depreciation and amortization	261	716	629
Total operating expenses	1,210,704	1,089,191	1,135,233
Income from operations	228,232	232,700	210,389
Interest expense	105,731	104,348	103,012
Interest expense to affiliated trusts	421	713	1,342
Capitalized interest	(3,987)	(4,083)	(4,174)
Merger termination fee	—	—	(103,000)
Other income—net	(33,298)	(4,817)	(14,928)
Income before income taxes	159,365	136,539	228,137
Income tax expense	12,031	7,051	31,374
Net income	147,334	129,488	196,763
Net loss attributable to noncontrolling interests	—	—	216
Net income attributable to Avista Corp. shareholders	$ 147,334	$ 129,488	$ 196,979
Weighted-average common shares outstanding (thousands)—basic	69,951	67,962	66,205
Weighted-average common shares outstanding (thousands)—diluted	70,085	68,102	66,329
Earnings per common share attributable to Avista Corp. shareholders:			
Basic	$ 2.11	$ 1.91	$ 2.98
Diluted	$ 2.10	$ 1.90	$ 2.97

The Accompanying Notes are an Integral Part of These Statements.

Consolidated Statements of Comprehensive Income

Avista Corporation

For the Years Ended December 31,

Dollars in thousands

	2021	2020	2019
Net income	$ 147,334	$ 129,488	$ 196,763
Other Comprehensive Income (loss):			
Change in unfunded benefit obligation for pension and other postretirement benefit plans—net of taxes of $888, $(1,095) and $(636), respectively	3,339	(4,119)	(2,393)
Total other comprehensive income (loss)	3,339	(4,119)	(2,393)
Comprehensive income	150,673	125,369	194,370
Comprehensive loss attributable to noncontrolling interests	—	—	216
Comprehensive income attributable to Avista Corporation shareholders	$ 150,673	$ 125,369	$ 194,586

The Accompanying Notes are an Integral Part of These Statements.

Consolidated Balance Sheets

Avista Corporation
As of December 31,
Dollars in thousands

	2021	2020
Assets:		
Current Assets:		
Cash and cash equivalents	$ 22,168	$ 14,196
Accounts and notes receivable—net	203,035	163,772
Materials and supplies, fuel stock and stored natural gas	84,733	67,451
Regulatory assets	43,783	13,673
Other current assets	80,754	84,885
Total current assets	434,473	343,977
Net utility property	5,225,515	4,991,612
Goodwill	52,426	52,426
Non-current regulatory assets	860,626	750,443
Other property and investments—net and other non-current assets	280,543	263,639
Total assets	$ 6,853,583	$ 6,402,097
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 133,096	$ 106,613
Current portion of long-term debt	250,000	—
Short-term borrowings	284,000	203,000
Regulatory liabilities	77,149	46,435
Other current liabilities	168,861	149,831
Total current liabilities	913,106	505,879
Long-term debt	1,898,370	2,008,534
Long-term debt to affiliated trusts	51,547	51,547
Pensions and other postretirement benefits	153,467	211,880
Deferred income taxes	642,709	594,712
Non-current regulatory liabilities	861,515	784,820
Other non-current liabilities and deferred credits	178,125	214,999
Total liabilities	4,698,839	4,372,371
Commitments and Contingencies (See Notes to Consolidated Financial Statements)		
Equity:		
Avista Corporation Shareholders' Equity:		
Common stock, no par value; 200,000,000 shares authorized; 71,497,523 and 69,238,901 shares issued and outstanding, respectively	1,380,152	1,286,068
Accumulated other comprehensive loss	(11,039)	(14,378)
Retained earnings	785,631	758,036
Total equity	2,154,744	2,029,726
Total liabilities and equity	$ 6,853,583	$ 6,402,097

The Accompanying Notes are an Integral Part of These Statements.

Consolidated Statements of Cash Flows

Avista Corporation
For the Years Ended December 31,
Dollars in thousands

	2021	2020	2019
Operating Activities:			
Net income	$ 147,334	$ 129,488	$ 196,763
Non-cash items included in net income:			
Depreciation and amortization	232,176	224,223	205,994
Provision for deferred income taxes	11,224	44,964	15,098
Power and natural gas cost amortizations (deferrals)—net	(51,847)	(9,923)	(45,917)
Amortization of debt expense	2,606	3,237	2,680
Amortization of investment in exchange power	—	—	1,633
Stock-based compensation expense	4,713	5,846	11,353
Equity-related AFUDC	(7,004)	(6,970)	(6,585)
Pension and other postretirement benefit expense	29,077	33,812	36,417
Other regulatory assets and liabilities and deferred debits and credits	676	10,287	65
Change in decoupling regulatory deferral	6,056	2,971	(10,327)
Realized and unrealized gain on assets and investments	(23,187)	(5,170)	(13,077)
Other	(2,859)	2,373	(7,899)
Contributions to defined benefit pension plan	(42,000)	(22,000)	(22,000)
Cash paid on settlement of interest rate swap agreements	(17,568)	(33,499)	(13,325)
Cash received on settlement of interest rate swap agreements	324	—	—
Changes in certain current assets and liabilities:			
Accounts and notes receivable	(46,107)	(10,960)	(4,366)
Materials and supplies, fuel stock and stored natural gas	(17,282)	(868)	(6,148)
Collateral posted for derivative instruments	(17,564)	1,579	63,974
Income taxes receivable	20,199	(41,363)	(8,736)
Other current assets	930	(2,401)	(3,657)
Accounts payable	33,369	(10,152)	7,471
Other current liabilities	4,074	15,530	(1,199)
Net cash provided by operating activities	267,340	331,004	398,212
Investing Activities:			
Utility property capital expenditures (excluding equity-related AFUDC)	(439,939)	(404,306)	(442,510)
Issuance of notes receivable	(1,841)	(4,393)	(7,303)
Equity and property investments	(16,001)	(5,925)	(13,508)
Proceeds from sale of investments	8,306	6,786	16,407
Other	4,559	(2,905)	1,403
Net cash used in investing activities	$ (444,916)	$ (410,743)	$ (445,511)

The Accompanying Notes are an Integral Part of These Statements.

Consolidated Statements of Cash Flows (continued)

Avista Corporation

For the Years Ended December 31,

Dollars in thousands

	2021	2020	2019
Financing Activities:			
Net increase (decrease) in short-term borrowings	$ 81,000	$ 17,200	$ (4,200)
Proceeds from issuance of long-term debt	140,000	165,000	180,000
Maturity of long-term debt and finance leases	(2,935)	(54,800)	(92,660)
Issuance of common stock, net of issuance costs	89,998	72,200	64,573
Cash dividends paid	(118,211)	(110,254)	(102,772)
Other	(4,304)	(5,307)	(2,402)
Net cash provided by financing activities	185,548	84,039	42,539
Net increase (decrease) in cash and cash equivalents	7,972	4,300	(4,760)
Cash and cash equivalents at beginning of year	14,196	9,896	14,656
Cash and cash equivalents at end of year	$ 22,168	$ 14,196	$ 9,896
Supplemental Cash Flow Information:			
Cash paid (received) during the year:			
Interest	$ 98,592	$ 97,717	$ 99,060
Income taxes paid	3,652	1,901	26,764
Income tax refunds	(22,330)	(918)	(979)
Non-cash financing and investing activities:			
Accounts payable for capital expenditures	23,938	32,039	25,644

The Accompanying Notes are an Integral Part of These Statements.

Consolidated Statements of Equity

Avista Corporation
For the Years Ended December 31,
Dollars in thousands, except per share amounts

	2021	2020	2019
Common Stock, Shares:			
Shares outstanding at beginning of year	69,238,901	67,176,996	65,688,356
Shares issued through equity compensation plans	93,806	139,726	75,399
Shares issued through Employee Investment Plan	14,480	17,179	3,653
Shares issued through sales agency agreements	2,150,336	1,905,000	1,409,588
Shares outstanding at end of year	71,497,523	69,238,901	67,176,996
Common Stock, Amount:			
Balance at beginning of year	$ 1,286,068	$ 1,210,741	$ 1,136,491
Equity compensation expense	5,079	5,535	10,568
Issuance of common stock through equity compensation plans	931	965	827
Issuance of common stock through Employee Investment Plan	610	674	175
Issuance of common stock through sales agency agreements—net of issuance costs	88,457	70,561	63,571
Payment of minimum tax withholdings for share-based payment awards	(993)	(2,408)	(891)
Balance at end of year	1,380,152	1,286,068	1,210,741
Accumulated Other Comprehensive Loss:			
Balance at beginning of year	(14,378)	(10,259)	(7,866)
Other comprehensive income (loss)	3,339	(4,119)	(2,393)
Balance at end of year	(11,039)	(14,378)	(10,259)
Retained Earnings:			
Balance at beginning of year	758,036	738,802	644,595
Net income attributable to Avista Corporation shareholders	147,334	129,488	196,979
Dividends on common stock	(119,739)	(110,254)	(102,772)
Balance at end of year	785,631	758,036	738,802
Total Avista Corporation shareholders' equity	$ 2,154,744	$ 2,029,726	$ 1,939,284
Noncontrolling Interests:			
Balance at beginning of year	$ —	$ —	$ 825
Net loss attributable to noncontrolling interests	—	—	(216)
Deconsolidation of noncontrolling interests related to sale of METALfx	—	—	(609)
Balance at end of year	—	—	—
Total equity	$ 2,154,744	$ 2,029,726	$ 1,939,284
Dividends declared per common share	$ 1.69	$ 1.62	$ 1.55

The Accompanying Notes are an Integral Part of These Statements.

Notes to Consolidated Financial Statements

Note 1. Summary of Significant Accounting Policies

Nature of Business

Avista Corp. is primarily an electric and natural gas utility with certain other business ventures. Avista Utilities is an operating division of Avista Corp., comprising its regulated utility operations in the Pacific Northwest. Avista Utilities provides electric distribution and transmission, and natural gas distribution services in parts of eastern Washington and northern Idaho. Avista Utilities also provides natural gas distribution service in parts of northeastern and southwestern Oregon. Avista Utilities has electric generating facilities in Washington, Idaho, Oregon and Montana. Avista Utilities also supplies electricity to a small number of customers in Montana, most of whom are employees who operate the Company's Noxon Rapids generating facility.

AERC is a wholly owned subsidiary of Avista Corp. The primary subsidiary of AERC is 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 all of the subsidiary companies in the non-utility businesses, with the exception of AJT Mining Properties, Inc., which is a subsidiary of AERC. See Note 24 for business segment information. See Note 26 for discussion of the sale of METALfx, which was an unregulated subsidiary of the Company.

Basis of Reporting

The consolidated financial statements include the assets, liabilities, revenues and expenses of the Company and its subsidiaries and other majority owned subsidiaries and variable interest entities for which the Company or its subsidiaries are the primary beneficiaries. Intercompany balances were eliminated in consolidation. The accompanying consolidated financial statements include the Company's proportionate share of utility plant and related operations resulting from its interests in jointly owned plants (see Note 8).

Use of Estimates

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported for assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates include:

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

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

Regulation

The Company is subject to state regulation in Washington, Idaho, Montana, Oregon and Alaska. The Company is also 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:

	2021	2020	2019
Avista Utilities			
Ratio of depreciation to average depreciable property	3.54%	3.43%	3.28%
Alaska Electric Light and Power Company			
Ratio of depreciation to average depreciable property	2.77%	2.77%	2.48%

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

	Avista Utilities	Alaska Electric Light and Power Company
Electric thermal/other production	26	42
Hydroelectric production	81	42
Electric transmission	50	43
Electric distribution	39	40
Natural gas distribution property	44	N/A
Other shorter-lived general plant	8	18

Allowance for Funds Used During Construction

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 Consolidated Statements of Income in the line item "capitalized interest." The equity component of AFUDC is included in the Consolidated Statements of Income in the line item "other income—net." The Company is permitted, under established regulatory rate practices, to recover the capitalized AFUDC, and a reasonable return thereon, through its inclusion in rate base and the provision for depreciation after the related utility plant is placed in service. Cash inflow related to AFUDC does not occur until the related utility plant is placed in service and included in rate base.

The WUTC and IPUC have authorized Avista Utilities to calculate AFUDC using its allowed rate of return. To the extent amounts calculated using this rate exceed the AFUDC amounts calculated using the FERC formula, Avista Utilities capitalizes the excess as a regulatory asset. The regulatory asset associated with plant in service is amortized over the average useful life of Avista Utilities' 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:

	2021	2020	2019
Avista Utilities	7.19%	7.25%	7.39%
Alaska Electric Light and Power Company	8.90%	8.04%	8.96%

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 consolidated income tax returns. The effect on deferred income taxes from a change in tax rates is recognized in income in the period that includes the enactment date unless a regulatory order specifies deferral of the effect of the change in tax rates over a longer period of time. The Company establishes a valuation allowance when it is more likely than not that all, or a portion, of a deferred tax asset will not be realized. Deferred income tax assets and liabilities and regulatory assets and liabilities are established for income tax benefits flowed through to customers.

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

The Company did not incur any penalties on income tax positions in 2021, 2020 or 2019. The Company would recognize interest accrued related to income tax positions as interest expense and any penalties incurred as other operating expense.

Stock-Based Compensation

The Company currently issues three types of stock-based compensation awards—restricted shares, market-based awards and performance-based awards. Historically, these stock compensation awards have not been material to the Company's overall financial results. 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 Consolidated Statements of Income of the following amounts for the years ended December 31 (dollars in thousands):

	2021	2020	2019
Stock-based compensation expense	$ 4,713	$ 5,846	$ 11,353
Income tax benefits	990	1,228	2,384
Excess tax expenses on settled share-based employee payments	(909)	(165)	(612)

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 eventually vest 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 that 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 that incorporates the probability of meeting the market targets based on historical returns relative to a peer group. The estimated fair value of the CEPS awards was estimated on the date of grant as the share price of Avista Corp. common stock on the date of grant.

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:

	2021	2020	2019
Restricted Shares			
Shares granted during the year	62,594	45,540	50,061
Shares vested during the year	34,854	56,203	48,228
Unvested shares at end of year	96,127	71,706	93,351
Unrecognized compensation expense at end of year (in thousands)	$ 2,215	$ 2,003	$ 2,054
TSR Awards			
TSR shares granted during the year	64,910	47,848	99,214
TSR shares vested during the year	77,174	71,299	106,858
TSR shares earned based on market metrics	58,652	—	—
Unvested TSR shares at end of year	107,854	122,133	178,035
Unrecognized compensation expense at end of year (in thousands)	$ 2,653	$ 2,296	$ 3,377
CEPS Awards			
CEPS shares granted during the year	64,910	47,848	49,609
CEPS shares vested during the year	38,590	35,622	53,454
CEPS shares earned based on market metrics	26,627	63,763	106,908
Unvested CEPS shares at end of year	107,854	83,464	88,990
Unrecognized compensation expense at end of year (in thousands)	$ 1,223	$ 1,090	$ 2,401

Outstanding restricted, TSR and CEPS share awards include a dividend component that is 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, 2021 and 2020, the Company had recognized a liability of $1.5 million and $0.8 million, respectively, related to the dividend equivalents payable on the outstanding and unvested share grants.

Other Income–Net

Other income—net consisted of the following items for the years ended December 31 (dollars in thousands):

	2021	2020	2019
Interest income	$ (1,943)	$ (1,952)	$ (2,587)
Interest on regulatory deferrals	(1,206)	(1,222)	(1,460)
Equity-related AFUDC	(7,004)	(6,970)	(6,585)
Non-service portion of pension and other postretirement benefit expenses	1,386	6,433	8,899
Earnings on investments	(21,402)	(905)	(14,299)
Other expense (income)	(3,129)	(201)	1,104
Total	$ (33,298)	$ (4,817)	$ (14,928)

Earnings per Common Share Attributable to Avista Corporation Shareholders

Basic earnings per common share attributable to Avista Corp. shareholders is computed by dividing net income attributable to Avista Corp. shareholders by the weighted-average number of common shares outstanding for the period. Diluted earnings per common share attributable to Avista Corp. shareholders is calculated by dividing net income attributable to Avista Corp. shareholders by diluted weighted-average common shares outstanding during the period, including common stock equivalent shares outstanding using the treasury stock method, unless such shares are anti-dilutive. Common stock equivalent shares include shares issuable under contingent stock awards. See Note 21 for earnings per common share calculations.

Cash and Cash Equivalents

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

Allowance for Doubtful Accounts

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

The following table presents the activity in the allowance for doubtful accounts during the years ended December 31 (dollars in thousands):

	2021	2020	2019
Allowance as of the beginning of the year	$ 11,387	$ 2,419	$ 5,233
Additions expensed during the year [1]	9,279	11,280	460
Net deductions [2]	(10,201)	(2,312)	(3,274)
Allowance as of the end of the year	$ 10,465	$ 11,387	$ 2,419

(1) Increases in 2021 and 2020 related to COVID-19 bad debt expense in excess of the amount recovered through rates.

(2) Increase in 2021 relates to COVID forgiveness program.

Utility Plant in Service

The cost of additions to utility plant in service, including an allowance for funds used during construction 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

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 10 for further discussion of the Company's AROs).

The Company recovers certain asset retirement costs through rates charged to customers as a portion of its depreciation expense for which the Company has not recorded asset retirement obligations.

The Company has recorded the amount of estimated retirement costs collected from customers (that do not represent legal or contractual obligations) and included them as a non-current regulatory liability on the Consolidated Balance Sheets in the following amounts as of December 31 (dollars in thousands):

	2021	2020
Regulatory liability for utility plant retirement costs	$ 350,190	$ 325,832

Goodwill

Goodwill arising from acquisitions represents the future economic benefit arising from other assets acquired in a business combination that are not individually identified and separately recognized. The Company evaluates goodwill for impairment using a fair value to carrying amount comparison (Step 1). The Company completed its annual evaluation of goodwill for potential impairment as of November 30, 2021 and determined that goodwill was not impaired at that time (carrying value was less than the determined fair value). There were no events or circumstances that changed between November 30, 2021 and December 31, 2021 that would more likely than not reduce the fair values of the reporting units below their carrying amounts.

There were no changes in the carrying amount of goodwill during 2020 and 2021, and the balance was as follows (dollars in thousands):

	AEL&P	Accumulated Impairment Losses	Total
Balance as of December 31, 2020 and 2021	$ 52,426	$ —	$ 52,426

Derivative Assets and Liabilities

Derivatives are recorded as either assets or liabilities on the Consolidated 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 PGAs, the ERM in Washington, the PCA mechanism in Idaho, and periodic general rates cases. The resulting regulatory assets associated with energy commodity derivative instruments have been concluded to be 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 that are 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 that is determined to be other-than-temporary.

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

The Company has multiple master netting agreements with a variety of entities that allow for cross-commodity netting of derivative agreements with the same counterparty (i.e., power derivatives can be netted with natural gas derivatives). In addition, some master netting agreements allow for the netting of commodity derivatives and interest rate swap derivatives for the same counterparty. The Company does not have any 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 Consolidated 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 swap derivatives and foreign currency exchange derivatives, are reported at estimated fair value on the Consolidated Balance Sheets. See Note 18 for the Company's fair value disclosures.

Regulatory Deferred Charges and Credits

The Company prepares its consolidated 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 that 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), are reflected as deferred charges or credits on the Consolidated Balance Sheets. These costs and/or obligations are not reflected in the Consolidated Statements of Income until the period during which matching revenues are recognized. The Company also has decoupling revenue deferrals. See Note 4 for discussion on decoupling revenue deferrals.

If at some point in the future the Company determines that 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.

See Note 23 for further details of regulatory assets and liabilities.

Unamortized Debt Expense

Unamortized debt expense includes debt issuance costs that are amortized over the life of the related debt. These costs are recorded as an offset to Long-Term Debt on the Consolidated Balance Sheets.

Unamortized Debt Repurchase Costs

Premiums paid or discounts received to repurchase debt are amortized over the remaining life of the original debt that was repurchased or, if new debt is issued in connection with the repurchase, these costs are amortized over the life of the new debt. These costs are recovered 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 any earnings in excess of the specified rate of return on the Company's investment in the licenses for its various hydroelectric projects. Per section 10(d) of the FPA, the Company must maintain these excess earnings in an appropriated retained earnings account until the termination of the licensing agreements or apply them to reduce the net investment in the licenses of the hydroelectric projects at the discretion of the FERC. The Company calculates the earnings in excess of the specified rate of return on an annual basis, usually during the second quarter.

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

	2021	2020
Appropriated retained earnings	$ 53,620	$ 47,473

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, 2021, the Company has not recorded any significant amounts related to unresolved contingencies. See Note 22 for further discussion of the Company's commitments and contingencies.

COVID-19

In 2020, the WUTC, IPUC, and OPUC approved accounting orders that allow the Company to defer certain net COVID-19 related costs and benefits. As such, as of December 31, 2021, the Company has deferred net costs of $1.1 million for all jurisdictions.

The respective regulatory authorities will determine the appropriateness and prudency of any deferred expenses when the Company seeks recovery. See "Regulatory Deferred Charges and Credits."

Note 2. New Accounting Standards

ASU 2018-13 "Fair Value Measurement (Topic 820)"

In August 2018, the FASB issued ASU No. 2018-13, which amends the fair value measurement disclosure requirements of ASC 820. The requirements of this ASU include additional disclosure regarding the range and weighted-average used to develop significant unobservable inputs for Level 3 fair value estimates and the elimination of certain other previously required disclosures, such as the narrative description of the valuation process for Level 3 fair value measurements. This ASU became effective on January 1, 2020 and the requirements of this ASU did not have a material impact on the Company's fair value disclosures. See Note 18 for the Company's fair value disclosures.

ASU No. 2018-14 "Compensation—Retirement Benefits—Defined Benefit Plans—General (Subtopic 715-20)"

In August 2018, the FASB issued ASU No. 2018-14, which amends ASC 715 to add, remove and/or clarify certain disclosure requirements related to defined benefit pension and other postretirement plans. The additional disclosure requirements are primarily narrative discussion of significant changes in the benefit obligations and plan assets. The removed disclosures are primarily information about accumulated other comprehensive income expected to be recognized over the next year and the effects of changes associated with assumed health care costs. This ASU became effective for periods ending after December 15, 2020 and the requirements of this ASU did not have a material impact on the Company's disclosures upon adoption.

Note 3. Balance Sheet Components

Materials and Supplies, Fuel Stock and Stored Natural Gas

Inventories of materials and supplies, fuel stock and stored natural gas are recorded at average cost for regulated operations and the lower of cost or market for non-regulated operations and consisted of the following as of December 31 (dollars in thousands):

	2021	2020
Materials and supplies	$ 62,003	$ 53,258
Fuel stock	5,126	4,658
Stored natural gas	17,604	9,535
Total	$ 84,733	$ 67,451

Other Current Assets

Other current assets consisted of the following as of December 31 (dollars in thousands):

	2021	2020
Collateral posted for derivative instruments after netting with outstanding derivative liabilities	$ 21,477	$ 4,336
Prepayments	24,387	24,411
Income taxes receivable	29,615	49,814
Other	5,275	6,324
Total	$ 80,754	$ 84,885

Other Property and Investments–Net and Other Non-Current Assets

Other property and investments—net and other non-current assets consisted of the following as of December 31 (dollars in thousands):

	2021	2020
Operating lease ROU assets	$ 70,133	$ 71,891
Finance lease ROU assets	43,697	47,338
Non-utility property	20,033	19,508
Equity investments	91,057	59,318
Investment in affiliated trust	11,547	11,547
Notes receivable	14,949	14,454
Deferred compensation assets	9,513	9,174
Assets held for sale (1)	—	3,462
Other	19,614	26,947
Total	$ 280,543	$ 263,639

(1) The Company sold certain subsidiary assets associated with Steam Plant Square and Brew Pub during 2021.

Other Current Liabilities

Other current liabilities consisted of the following as of December 31 (dollars in thousands):

	2021	2020
Accrued taxes other than income taxes	$ 41,706	$ 45,099
Derivative liabilities	28,801	14,008
Employee paid time off accruals	27,741	26,495
Accrued interest	17,538	17,083
Pensions and other postretirement benefits	13,582	11,987
Other	39,493	35,159
Total	$ 168,861	$ 149,831

Other Non-Current Liabilities and Deferred Credits

Other non-current liabilities and deferred credits consisted of the following as of December 31 (dollars in thousands):

	2021	2020
Operating lease liabilities	$ 66,068	$ 67,716
Finance lease liabilities	45,730	48,815
Deferred investment tax credits	29,313	29,866
Asset retirement obligations	17,142	17,194
Derivative liabilities	4,525	37,427
Other	15,347	13,981
Total	$ 178,125	$ 214,999

Note 4. Revenue

ASC 606 defines 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. Given that 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. Given that all revenue recognition criteria are met upon the delivery of energy to customers, revenue is recognized immediately at that time.

Revenues from contracts with customers are presented in the Consolidated Statements of Income in the line item "Utility revenues, exclusive of alternative revenue programs."

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,
- current rates,
- meter reading dates,
- actual native load for electricity,
- actual throughput for natural gas, and
- electric line losses and natural gas system losses.

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

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

	2021	2020
Unbilled accounts receivable	$ 74,479	$ 71,258

Non-Derivative Wholesale Contracts

The Company has certain wholesale contracts which are not accounted for as derivatives and, accordingly, are within the scope of ASC 606 and considered revenue from contracts with customers. Revenue is recognized as energy is delivered to the customer or the service is available for specified period of time, consistent with the discussion of rate regulated sales above.

Alternative Revenue Programs (Decoupling)

ASC 606 retained existing GAAP associated with alternative revenue programs, which specified that alternative revenue programs are contracts between an entity and a regulator of utilities, not a contract between an entity and a customer. GAAP requires that an entity present revenue arising from alternative revenue programs separately from revenues arising from contracts with customers on the face of the Consolidated 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 Consolidated 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 any 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 current period Consolidated Statements of Income. Any 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 which must be 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 Consolidated 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 specifically scoped out of ASC 606. As such, these revenues 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 those transactions that are entered into and settled within the same month.

Other Utility Revenue

Other utility revenue includes rent, sales of materials, late fees and other charges that do not represent contracts with customers. This revenue is scoped out of ASC 606, as this revenue does not represent items where a customer is a party that has contracted with the Company to obtain goods or services that are an output of the Company's ordinary activities in exchange for consideration. As such, these revenues are presented separately from revenue from contracts with customers.

Other Considerations for Utility Revenues

Gross Versus Net Presentation

Revenues and resource costs from Avista Utilities' settled energy contracts that are "booked out" (not physically delivered) are reported on a net basis as part of derivative revenues.

Utility-related taxes collected from customers (primarily state excise taxes and city utility taxes) are taxes that are imposed on Avista Utilities as opposed to being imposed on its customers; therefore, Avista Utilities 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). The utility-related taxes collected from customers at AEL&P are imposed on the customers rather than AEL&P; therefore, the customers are the taxpayers and AEL&P is acting as their agent. As such, these transactions at AEL&P are presented on a net basis within revenue from contracts with customers.

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

	2021	2020	2019
Utility-related taxes	$ 62,736	$ 59,319	$ 59,528

Non-Utility Revenues

Revenue from Contracts with Customers

Non-utility revenue from contracts with customers is derived from contracts with one performance obligation. Prior to its sale in April 2019 (See Note 26 for further discussion on the sale of METALfx), METALfx had one performance obligation, the delivery of a product, and revenues were recognized when the risk of loss transferred to the customer, which occurred when products were shipped.

Other Revenue

Other non-utility revenue primarily relates to rent revenue, which is scoped out of ASC 606; therefore, this revenue is presented separately from revenue from contracts with customers.

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 does have one capacity agreement where the customer makes payments throughout the year. As of December 31, 2021, the Company estimates it had unsatisfied capacity performance obligations of $17.4 million, which will be recognized as revenue in future periods as the capacity is provided to the customers. These performance obligations are not reflected in the financial statements, as the Company has not received payment for these services.

Disaggregation of Total Operating Revenue

The following table disaggregates total operating revenue by segment and source for the years ended December 31 (dollars in thousands):

	2021	2020	2019
AVISTA UTILITIES			
Revenue from contracts with customers	$ 1,233,904	$ 1,157,746	$ 1,152,125
Derivative revenues	152,590	110,313	118,741
Alternative revenue programs	(6,635)	(3,814)	9,614
Deferrals and amortizations for rate refunds to customers	2,984	5,335	4,509
Other utility revenues	10,156	7,888	10,884
Total Avista Utilities	1,392,999	1,277,468	1,295,873
AEL&P			
Revenue from contracts with customers	45,051	42,624	36,779
Deferrals and amortizations for rate refunds to customers	(190)	(190)	(190)
Other utility revenues	505	375	676
Total AEL&P	45,366	42,809	37,265
OTHER			
Revenue from contracts with customers	2	564	11,286
Other revenues	569	1,050	1,198
Total Other	571	1,614	12,484
Total operating revenues	$ 1,438,936	$ 1,321,891	$ 1,345,622

Utility Revenue from Contracts with Customers by Type and Service

The following table disaggregates revenue from contracts with customers associated with the Company's electric operations for the years ended December 31 (dollars in thousands):

	2021			2020			2019		
	Avista Utilities	AEL&P	Total Utility	Avista Utilities	AEL&P	Total Utility	Avista Utilities	AEL&P	Total Utility
ELECTRIC OPERATIONS									
Revenue from contracts with customers									
Residential	$ 394,717	$ 18,940	$ 413,657	$ 377,785	$ 18,618	$ 396,403	$ 369,102	$ 17,134	$ 386,236
Commercial and governmental	326,173	25,861	352,034	303,972	23,754	327,726	317,589	19,391	336,980
Industrial	106,756	—	106,756	103,103	—	103,103	105,802	—	105,802
Public street and highway lighting	7,472	250	7,722	7,303	252	7,555	7,448	254	7,702
Total retail revenue	835,118	45,051	880,169	792,163	42,624	834,787	799,941	36,779	836,720
Transmission	21,005	—	21,005	18,236	—	18,236	18,180	—	18,180
Other revenue from contracts with customers	33,870	—	33,870	19,252	—	19,252	26,969	—	26,969
Total revenue from contracts with customers	$ 889,993	$ 45,051	$ 935,044	$ 829,651	$ 42,624	$ 872,275	$ 845,090	$ 36,779	$ 881,869

The following table disaggregates revenue from contracts with customers associated with the Company's natural gas operations for the years ended December 31 (dollars in thousands):

	2021 Avista Utilities	2020 Avista Utilities	2019 Avista Utilities
NATURAL GAS OPERATIONS			
Revenue from contracts with customers			
Residential	$ 221,405	$ 213,612	$ 196,430
Commercial	100,819	94,937	92,168
Industrial and interruptible	7,796	7,128	5,263
Total retail revenue	330,020	315,677	293,861
Transportation	8,547	7,917	8,674
Other revenue from contracts with customers	5,344	4,501	4,500
Total revenue from contracts with customers	$ 343,911	$ 328,095	$ 307,035

Note 5. Leases

ASC 842, outlines a model for entities to use in accounting for leases. The core principle of the model is that an entity should recognize the ROU assets and liabilities that arise 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 consolidated financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases.

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 arising from the lease. Operating and finance 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 and finance lease ROU assets also include any 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 that the Company will exercise that option. Lease expense for lease payments is recognized on a straight-line basis over the lease term. Any 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 Energy. In addition, the State of Montana and Avista Corp. are engaged in litigation regarding lease terms, including how much money, if any, the State of Montana should return to Avista Corp. Amounts recorded for this lease are uncertain and amounts may change in the future depending on the outcome of the ongoing litigation. Any reduction in future lease payments or the return of previously paid amounts to Avista Corp. will be included in the future ratemaking process.

In addition to the lease with the State of Montana, the Company also 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 72 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 any material residual value guarantees or material restrictive covenants.

Avista Corp. does not record leases with a term of 12 months or less in the Consolidated Balance Sheets. Total short-term lease costs for the year ended December 31, 2021 are immaterial.

Finance Lease

AEL&P has a PPA which is treated as a finance lease for accounting purposes related to the Snettisham Hydroelectric Project, which expires in 2034. For ratemaking purposes, this lease is treated as an operating lease with a constant level of annual rental expense (straight line rent expense). Because of this regulatory treatment, any difference between the operating lease expense for ratemaking purposes and the expenses recognized under GAAP (interest expense and amortization of the finance lease ROU asset) is recorded as a regulatory asset and amortized during the later years of the lease when the finance lease expense is less than the operating lease expense included in base rates. The amortization of the ROU asset is included in depreciation and amortization and the interest associated with the lease liability is included in interest expense on the Consolidated Statements of Income.

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

	2021	2020
Operating lease cost:		
Fixed lease cost (Other operating expenses)	$ 4,970	$ 4,746
Variable lease cost (Other operating expenses)	1,180	1,099
Total operating lease cost	$ 6,150	$ 5,845
Finance lease cost:		
Amortization of ROU asset (Depreciation and amortization)	$ 3,641	$ 3,641
Interest on lease liabilities (Interest expense)	2,522	2,662
Total finance lease cost	$ 6,163	$ 6,303

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

	2021	2020
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash outflows:		
Operating lease payments	$ 4,805	$ 4,612
Interest on finance lease	2,522	2,662
Total operating cash outflows	$ 7,327	$ 7,274
Finance cash outflows:		
Principal payments on finance lease	$ 2,935	$ 2,800

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

	2021	2020
Operating Leases		
Operating lease ROU assets (Other property and investments—net and other non-current assets)	$ 70,133	$ 71,891
Other current liabilities	$ 4,301	$ 4,249
Other non-current liabilities and deferred credits	66,068	67,716
Total operating lease liabilities	$ 70,369	$ 71,965
Finance Leases		
Finance lease ROU assets (Other property and investments—net and other non-current assets)	$ 43,697	$ 47,338
Other current liabilities	$ 3,085	$ 2,935
Other non-current liabilities and deferred credits	45,730	48,815
Total finance lease liabilities	$ 48,815	$ 51,750
Weighted-Average Remaining Lease Term		
Operating leases	24.22 years	25.20 years
Finance leases	6.32 years	7.22 years
Weighted-Average Discount Rate		
Operating leases	4.28%	4.28%
Finance leases	4.35%	4.62%

Maturities of lease liabilities (including principal and interest) were as follows as of December 31, 2021 (dollars in thousands):

	Operating Leases	Finance Leases
2022	$ 4,820	$ 5,460
2023	4,849	5,456
2024	4,875	5,459
2025	4,882	5,454
2026	4,867	5,456
Thereafter	91,845	38,204
Total lease payments	$ 116,138	$ 65,489
Less: imputed interest	(45,769)	(16,674)
Total	$ 70,369	$ 48,815

Maturities of lease liabilities (including principal and interest) were as follows as of December 31, 2020 (dollars in thousands):

	Operating Leases	Finance Leases
2021	$ 4,779	$ 5,457
2022	4,799	5,460
2023	4,827	5,456
2024	4,852	5,459
2025	4,865	5,454
Thereafter	96,734	43,661
Total lease payments	$ 120,856	$ 70,947
Less: imputed interest	(48,891)	(19,197)
Total	$ 71,965	$ 51,750

Note 6. Variable Interest Entities

Lancaster Power Purchase Agreement

The Company has a PPA for the purchase of all the output of the Lancaster Plant, a 270 MW natural gas-fired combined cycle combustion turbine plant located in Kootenai County, Idaho, owned by an unrelated third-party (Rathdrum Power LLC), through 2026.

Avista Corp. has a variable interest in the PPA. Accordingly, Avista Corp. made an evaluation of which interest holders have the power to direct the activities that most significantly impact the economic performance of the entity and which interest holders have the obligation to absorb losses or receive benefits that could be significant to the entity. Avista Corp. pays a fixed capacity and operations and maintenance payment and certain monthly variable costs under the PPA. Under the terms of the PPA, Avista Corp. makes the dispatch decisions, provides all natural gas fuel and receives all of the electric energy output from the Lancaster Plant. However, Rathdrum Power LLC (the owner) controls the daily operation of the Lancaster Plant and makes operating and maintenance decisions. Rathdrum Power LLC controls all of the rights and obligations of the Lancaster Plant after the expiration of the PPA in 2026 and Avista Corp. does not have any further obligations after the expiration. It is estimated that the plant will have 15 to 25 years of useful life after that time. Rathdrum Power LLC bears the maintenance risk of the plant and will receive the residual value of the Lancaster Plant. Avista Corp. has no debt or equity investments in the Lancaster Plant and does not provide financial support through liquidity arrangements or other commitments (other than the PPA). Based on its analysis, Avista Corp. does not consider itself to be the primary beneficiary of the Lancaster Plant. Accordingly, neither the Lancaster Plant nor Rathdrum Power LLC is included in Avista Corp.'s consolidated financial statements. The Company has a future contractual obligation of $143.4 million under the PPA (representing the fixed capacity and operations and maintenance payments through 2026) and believes this would be its maximum exposure to loss. However, the Company believes that such costs will be recovered through retail rates.

Limited Partnerships and Similar Entities

Under current GAAP, a limited partnership or similar legal entity that is the functional equivalent of a limited partnership is considered a VIE regardless of whether it otherwise qualifies as a voting interest entity unless a simple majority or lower threshold of the "unrelated" limited partners (i.e., parties other than the general partner, entities under common control with the general partner, and other parties acting on behalf of the general partner) have substantive kick-out rights (including liquidation rights) or participating rights.

The Company has investments in limited partnerships (or the functional equivalent) where Avista Corp. is a limited partner investor in an investment fund where the general partner makes all of the investment and operating decisions with regards to the partnership and fund. To remove the general partner from any of the funds, approval from greater than a simple majority of the limited partners is required. As such, the limited partners do not have substantive kick-out rights and these investments are considered VIEs. Consolidation of these VIEs by Avista Corp. is not required because the Company does not have majority ownership in any of the funds, it does not have the power to direct any activities of the funds, and it does not have the power to appoint executive leadership, including the board of directors.

Avista Corp. participates in profits and losses of the investment funds based on its ownership percentage and its losses are capped at its total initial investment in the funds. As of December 31, 2021, Avista Corp. has invested $75.4 million in these investment funds, with an additional commitment of $27.0 million remaining to be invested. In addition, the Company is not allowed to withdraw any capital contributions from the investment funds until after the funds' expiration dates and all liabilities of the funds are settled. The expiration dates range from 2022 to 2040, with three investments having no termination date (as they are perpetual). One of the funds is closed and expired and the Company is awaiting final distribution as soon as the underlying investments are liquidated. As of December 31, 2021, the Company has a total carrying amount of $79.2 million in these investment funds.

Note 7. Derivatives and Risk Management

Energy Commodity Derivatives

Avista Corp. is exposed to market risks relating to changes in electricity and natural gas commodity prices and certain other fuel prices. Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. Avista Corp. utilizes derivative instruments, such as forwards, futures, swap derivatives and options in order 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, the Company 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. On the basis of 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, 2021 that are expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)
Year	MWh	MWh	mmBTUs	mmBTUs	MWh	MWh	mmBTUs	mmBTUs
2022	129	—	7,114	61,405	234	452	3,933	31,485
2023	—	—	378	23,218	—	—	1,360	9,323
2024	—	—	228	3,413	—	—	1,370	228
2025	—	—	—	—	—	—	1,115	—

As of December 31, 2021, there are no expected deliveries of energy commodity derivatives after 2025.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2020 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	
	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)
Year	MWh	MWh	mmBTUs	mmBTUs	MWh	MWh	mmBTUs	mmBTUs
2021	1	224	10,353	65,188	17	451	5,448	39,273
2022	—	—	450	25,525	—	—	1,360	12,030
2023	—	—	—	4,950	—	—	1,360	900
2024	—	—	—	—	—	—	1,370	—
2025	—	—	—	—	—	—	1,115	—

As of December 31, 2020, there were no expected deliveries of energy commodity derivatives after 2025.

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

The electric and natural gas derivative contracts above will be included in either power supply costs or natural gas supply costs during the period they are scheduled to be delivered and will be included in the various deferral and recovery mechanisms (ERM, PCA, and PGAs), or in the general rate case process, and are expected to be collected 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 that Avista Corp. has outstanding as of December 31 (dollars in thousands):

	2021	2020
Number of contracts	25	22
Notional amount (in United States dollars)	$ 8,571	$ 3,860
Notional amount (in Canadian dollars)	10,957	4,949

Interest Rate Swap Derivatives

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

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

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
December 31, 2021	13	140,000	2022
	2	20,000	2023
	1	10,000	2024
December 31, 2020	4	45,000	2021
	11	120,000	2022
	1	10,000	2023

See Note 16 for discussion of the bond purchase agreement and the related settlement of interest rate swaps in connection with the pricing of the bonds in September 2021.

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

Summary of Outstanding Derivative Instruments

The amounts recorded on the Consolidated Balance Sheets as of December 31, 2021 and December 31, 2020 reflect the offsetting of derivative assets and liabilities where a legal right of offset exists.

The following table presents the fair values and locations of derivative instruments recorded on the Consolidated Balance Sheets as of December 31, 2021 (in thousands):

	Fair Value			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) on Balance Sheet
Foreign currency exchange derivatives				
Other current liabilities	$ —	$ (19)	$ —	$ (19)
Interest rate swap derivatives				
Other property and investments—net and other non-current assets	1,149	—	—	1,149
Other current liabilities	1,170	(25,196)	—	(24,026)
Other non-current liabilities and deferred credits	—	(78)	—	(78)
Energy commodity derivatives				
Other current assets	1,506	(107)	—	1,399
Other property and investments—net and other non-current assets	6,844	(5,335)	—	1,509
Other current liabilities	25,771	(39,616)	9,089	(4,756)
Other non-current liabilities and deferred credits	141	(4,589)	—	(4,448)
Total derivative instruments recorded on the balance sheet	$ 36,581	$ (74,940)	$ 9,089	$ (29,270)

The following table presents the fair values and locations of derivative instruments recorded on the Consolidated Balance Sheets as of December 31, 2020 (in thousands):

Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Fair Value Net Asset (Liability) on Balance Sheet
Foreign currency exchange derivatives				
Other current assets	$ 30	$ —	$ —	$ 30
Interest rate swap derivatives				
Other current liabilities	—	(19,575)	8,050	(11,525)
Other non-current liabilities and deferred credits	952	(32,190)	—	(31,238)
Energy commodity derivatives				
Other current assets	9,203	(8,306)	—	897
Other property and investments—net and other non-current assets	1,755	(1,159)	—	596
Other current liabilities	11,037	(14,007)	487	(2,483)
Other non-current liabilities and deferred credits	1,725	(8,043)	129	(6,189)
Total derivative instruments recorded on the balance sheet	$ 24,702	$ (83,280)	$ 8,666	$ (49,912)

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 a downgrade in Avista Corp.'s credit ratings or changes in market prices, additional collateral may be required. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against Avista Corp.'s credit facilities and cash. Avista Corp. actively monitors the exposure to possible collateral calls and takes steps to mitigate capital requirements.

The following table presents Avista Corp.'s collateral outstanding related to its derivative instruments as of December 31 (in thousands):

	2021	2020
Energy commodity derivatives		
Cash collateral posted	$ 30,567	$ 4,953
Letters of credit outstanding	34,000	23,500
Balance sheet offsetting (cash collateral against net derivative positions)	9,089	616
Interest rate swap derivatives		
Cash collateral posted (offset by net derivative positions)	—	8,050

There were no letters of credit outstanding related to interest rate swap derivatives as of December 31, 2021 and December 31, 2020.

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

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

	2021	2020
Interest rate swap derivatives		
Liabilities with credit-risk-related contingent features	$ 25,274	$ 50,813
Additional collateral to post	25,274	42,763

Note 8. Jointly Owned Electric Facilities

The Company has a 15 percent ownership interest in Units 3 & 4 of the Colstrip generating station, a coal-fired plant located in southeastern Montana, and provides financing for its ownership interest in the project. Pursuant to the ownership and operating agreements among the co-owners, the Company's share of related fuel costs as well as operating expenses for plant in service are included in the corresponding accounts in the Consolidated Statements of Income.

The Company's share of utility plant in service for Colstrip and accumulated depreciation (inclusive of the ARO assets and accumulated amortization) were as follows as of December 31 (dollars in thousands):

	2021	2020
Utility plant in service	$ 395,028	$ 391,922
Accumulated depreciation	(302,220)	(284,282)

See Note 10 for further discussion of AROs.

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

Note 9. Property, Plant and Equipment

Net Utility Property

Net utility property consisted of the following as of December 31 (dollars in thousands):

	2021	2020
Utility plant in service	$ 7,166,580	$ 6,809,797
Construction work in progress	205,405	175,767
Total	7,371,985	6,985,564
Less: Accumulated depreciation and amortization	2,146,470	1,993,952
Total net utility property	$ 5,225,515	$ 4,991,612

Gross Property, Plant and Equipment

The gross balances of the major classifications of property, plant and equipment are detailed in the following table as of December 31 (dollars in thousands):

	2021	2020
Avista Utilities:		
Electric production	$ 1,494,371	$ 1,457,497
Electric transmission	945,624	862,987
Electric distribution	2,093,937	1,978,868
Electric construction work-in-progress (CWIP) and other	424,733	384,372
Electric total	4,958,665	4,683,724
Natural gas underground storage	55,684	53,351
Natural gas distribution	1,356,477	1,282,563
Natural gas CWIP and other	87,852	83,644
Natural gas total	1,500,013	1,419,558
Common plant (including CWIP)	740,339	712,609
Total Avista Utilities	7,199,017	6,815,891
AEL&P:		
Electric production	106,094	105,076
Electric transmission	22,691	22,419
Electric distribution	27,138	25,814
Electric CWIP and other	7,319	6,677
Electric total	163,242	159,986
Common plant	9,726	9,687
Total AEL&P	172,968	169,673
Total gross utility property	7,371,985	6,985,564
Other (1)	17,818	16,394
Total	$ 7,389,803	$ 7,001,958

(1) Included in other property and investments-net and other non-current assets on the Consolidated Balance Sheets. Accumulated depreciation was $2.3 million as of December 31, 2021 and $2.2 million as of December 31, 2020 for the other businesses.

Note 10. Asset Retirement Obligations

The Company has recorded liabilities for future AROs to:

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

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

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

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

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

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

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

	2021	2020	2019
Asset retirement obligation at beginning of year	$ 17,194	$ 20,338	$ 18,266
Liabilities incurred	825	(2,315)	2,699
Liabilities settled	(1,541)	(1,645)	(1,503)
Accretion expense	664	816	876
Asset retirement obligation at end of year	$ 17,142	$ 17,194	$ 20,338

Note 11. Pension Plans and Other Postretirement Benefit Plans

The pension and other postretirement benefit plans described below only relate to Avista Utilities. AEL&P (not discussed below) participates in a defined contribution multiemployer plan for its union workers and a defined contribution money purchase pension plan for its nonunion workers. None of the subsidiary retirement plans, individually or in the aggregate, are significant to Avista Corp.

Avista Utilities

The Company has a defined benefit pension plan covering the majority of all regular full-time employees at Avista Utilities that were hired prior to January 1, 2014. 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 participate in a defined contribution 401(k) plan in lieu of a defined benefit pension plan. Union employees hired on or after January 1, 2014 are still covered under the defined benefit pension plan. The Company's funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. The Company contributed $42.0 million in cash to the pension plan in 2021, and $22.0 million in 2020 and 2019. The Company expects to contribute $42.0 million in cash to the pension plan in 2022.

The Company also has a SERP that provides additional pension benefits to certain executive officers and certain key employees of the Company. The SERP is intended to provide 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 that benefit payments under the pension plan and the SERP will total (dollars in thousands):

	2022	2023	2024	2025	2026	Total 2027–2031
Expected benefit payments	$ 43,282	$ 43,218	$ 43,675	$ 44,319	$ 43,810	$ 228,585

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

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

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

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

	2022	2023	2024	2025	2026	Total 2027–2031
Expected benefit payments	$ 6,960	$ 7,140	$ 7,291	$ 7,453	$ 7,560	$ 39,646

The Company expects to contribute $7.2 million to other postretirement benefit plans in 2022, representing expected benefit payments to be paid during the year excluding the Medicare Part D subsidy. The Company uses a December 31 measurement date for its pension and other postretirement benefit plans.

The following table sets forth the pension and other postretirement benefit plan disclosures as of December 31, 2021 and 2020 and the components of net periodic benefit costs for the years ended December 31, 2021, 2020 and 2019 (dollars in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2021	2020	2021	2020
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 826,915	$ 742,382	$ 161,233	$ 159,296
Service cost	25,306	22,392	4,114	3,902
Interest cost	26,160	27,853	5,139	6,042
Actuarial (gain)/loss	(13,997)	74,688	2,808	(2,589)
Benefits paid	(65,342)	(40,400)	(5,696)	(5,418)
Benefit obligation as of end of year	$ 799,042	$ 826,915	$ 167,598	$ 161,233
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 722,024	$ 642,063	52,173	$ 44,853
Actual return on plan assets	50,370	96,591	7,371	7,320
Employer contributions	42,000	22,000	—	—
Benefits paid	(63,431)	(38,630)	—	—
Fair value of plan assets as of end of year	$ 750,963	$ 722,024	$ 59,544	$ 52,173
Funded status	$ (48,079)	$ (104,891)	$ (108,054)	$ (109,060)
Amounts recognized in the Consolidated Balance Sheets:				
Other current liabilities	$ (1,951)	$ (1,943)	$ (684)	$ (669)
Non-current liabilities	(46,128)	(102,948)	(107,370)	(108,391)
Net amount recognized	$ (48,079)	$ (104,891)	$ (108,054)	$ (109,060)
Accumulated pension benefit obligation	$ 685,493	$ 710,023		
Accumulated postretirement benefit obligation:				
For retirees			$ 78,347	$ 75,876
For fully eligible employees			$ 32,144	$ 32,097
For other participants			$ 57,107	$ 53,260
Included in accumulated other comprehensive loss (income) (net of tax):				
Unrecognized prior service cost (credit)	$ 1,699	$ 1,902	$ (2,741)	$ (3,570)
Unrecognized net actuarial loss	94,109	119,318	48,872	53,737
Total	95,808	121,220	46,131	50,167
Less regulatory asset	(85,550)	(108,301)	(45,350)	(48,708)
Accumulated other comprehensive loss for unfunded benefit obligation for pensions and other postretirement benefit plans	$ 10,258	$ 12,919	$ 781	$ 1,459

	Pension Benefits		Other Postretirement Benefits	
	2021	2020	2021	2020
Weighted-average assumptions as of December 31:				
Discount rate for benefit obligation	3.39%	3.25%	3.40%	3.27%
Discount rate for annual expense	3.25%	3.85%	3.27%	3.89%
Expected long-term return on plan assets	5.40%	5.50%	4.60%	5.30%
Rate of compensation increase	4.66%	4.74%		
Medical cost trend pre-age 65—initial			6.00%	6.25%
Medical cost trend pre-age 65—ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2026	2026
Medical cost trend post-age 65—initial			6.00%	6.25%
Medical cost trend post-age 65—ultimate			5.00%	5.00%
Ultimate medical cost trend year post-age 65			2026	2026

	Pension Benefits			Other Postretirement Benefits		
	2021	2020	2019	2021	2020	2019
Components of net periodic benefit cost:						
Service cost [(a)]	$ 25,306	$ 22,392	$ 19,755	$ 4,114	$ 3,902	$ 3,006
Interest cost	26,160	27,853	28,417	5,139	6,042	5,598
Expected return on plan assets	(39,088)	(34,886)	(31,763)	(2,400)	(2,377)	(2,101)
Amortization of prior service cost (credit)	257	257	257	(921)	(958)	(981)
Net loss recognition	6,645	6,717	10,216	3,865	4,871	4,013
Net periodic benefit cost	$ 19,280	$ 22,333	$ 26,882	$ 9,797	$ 11,480	$ 9,535

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

Plan Assets

The Finance Committee of the Company's 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, trusts and partnerships that hold marketable debt and equity securities, real estate, and absolute return. 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 also investment ranges for each asset class. The target investment allocation percentages are typically the midpoint of the established range.

The target investment allocation percentages by asset classes are indicated in the table below:

	2021	2020
Equity securities	55%	35%
Debt securities	40%	49%
Real estate	5%	7%
Absolute return	0%	9%

The target investment allocation percentages were revised in the first quarter of 2021 and the pension plan assets were reinvested to move toward the new target investment allocation percentages. The target asset allocation percentages were modified to better align the asset allocations with the funded status of the pension plan.

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 that are comparable in coupon, rating, maturity and industry).

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

The Company's investments in common/collective trusts have redemption limitations that permit quarterly redemptions following notice requirements of 45 to 60 days. Most of the Company's investments in closely held investments and partnership interests have redemption limitations that range from bi-monthly to semi-annually following redemption notice requirements of 60 to 90 days. One investment in a partnership has a lock-up for redemption currently expiring in 2022 and is subject to extension.

The following table discloses by level within the fair value hierarchy (see Note 18 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2021 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 6,259	$ —	$ 6,259
Fixed income securities:				
U.S. government issues	—	19,310	—	19,310
Corporate issues	—	233,496	—	233,496
International issues	—	34,270	—	34,270
Municipal issues	—	18,558	—	18,558
Mutual funds:				
U.S. equity securities	236,552	—	—	236,552
International equity securities	112,873	—	—	112,873
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts:				
Real estate	—	—	—	31,040
Partnership/closely held investments:				
Absolute return (1)	—	—	—	363
International equity securities	—	—	—	50,427
Real estate	—	—	—	7,815
Total	$ 349,425	$ 311,893	$ —	$ 750,963

The following table discloses by level within the fair value hierarchy (see Note 18 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2020 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 3,309	$ —	$ 3,309
Fixed income securities:				
U.S. government issues	—	10,990	—	10,990
Corporate issues	—	279,857	—	279,857
International issues	—	39,634	—	39,634
Municipal issues	—	22,431	—	22,431
Mutual funds:				
U.S. equity securities	146,375	—	—	146,375
International equity securities	96,311	—	—	96,311
Absolute return (1)	11,640	—	—	11,640
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts:				
Real estate	—	—	—	29,532
Partnership/closely held investments:				
Absolute return (1)	—	—	—	47,188
International equity securities	—	—	—	26,760
Real estate	—	—	—	7,997
Total	$ 254,326	$ 356,221	$ —	$ 722,024

(1) This category invests in multiple strategies to diversify risk and reduce volatility. The strategies include: (a) event driven, relative value, convertible, and fixed income arbitrage, (b) distressed investments, (c) long/short equity and fixed income and (d) market neutral strategies.

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 will determine fair value based upon other inputs (including valuations of securities that are comparable in coupon, rating, maturity and industry). The target asset allocation was 60 percent equity securities and 40 percent debt securities in both 2021 and 2020.

The fair value of other postretirement plan assets was determined as of December 31, 2021 and 2020.

The following table discloses by level within the fair value hierarchy (see Note 18 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2021 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Balanced index mutual fund [(1)]	$ 59,545	$ —	$ —	$ 59,545

The following table discloses by level within the fair value hierarchy (see Note 18 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2020 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Balanced index mutual fund [(1)]	$ 52,173	$ —	$ —	$ 52,173

(1) The balanced index fund for 2021 and 2020 is a single mutual fund that includes a percentage of U.S. equity and fixed income securities and International equity and fixed income securities.

401(k) Plans and Executive Deferral Plan

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

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

	2021	2020	2019
Employer 401(k) matching contributions	$ 11,671	$ 11,742	$ 10,412

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 included in other property and investments-net and corresponding deferred compensation liabilities included in other non-current liabilities and deferred credits on the Consolidated Balance Sheets of the following amounts as of December 31 (dollars in thousands):

	2021	2020
Deferred compensation assets and liabilities	$ 9,513	$ 9,174

Note 12. Accounting for Income Taxes

Income Tax Expense

Income tax expense consisted of the following for the years ended December 31 (dollars in thousands):

	2021	2020	2019
Current income tax expense (benefit)	$ 807	$ (37,913)	$ 16,276
Deferred income tax expense	11,224	44,964	15,098
Total income tax expense	$ 12,031	$ 7,051	$ 31,374

State income taxes do not represent a significant portion of total income tax expense on the Consolidated Statements of Income for any periods presented.

A reconciliation of federal income taxes derived from the statutory federal tax rate of 21 percent applied to income before income taxes as set forth in the accompanying Consolidated Statements of Income is as follows for the years ended December 31 (dollars in thousands):

	2021		2020		2019	
Federal income taxes at statutory rates	$ 33,467	21.0%	$ 28,673	21.0%	$ 47,909	21.0%
Increase (decrease) in tax resulting from:						
Tax effect of regulatory treatment of utility plant differences	(13,820)	(8.7)	(12,893)	(9.4)	(9,967)	(4.3)
State income tax expense	1,385	0.8	814	0.6	1,465	0.6
Acquisition costs	—	—	—	—	(1,712)	(0.7)
Flow through related to deduction of meters and mixed service costs (1)	(8,678)	(5.4)	—	—	—	—
Non-plant excess deferred turnaround (2)	—	—	(8,476)	(6.2)	(5,690)	(2.5)
Tax loss on sale of METALfx	—	—	—	—	(1,272)	(0.6)
Customer refunds related to prior years at 35 percent	—	—	(1,189)	(0.9)	—	—
Other	(323)	(0.2)	122	0.1	641	0.3
Total income tax expense	$ 12,031	7.5%	$ 7,051	5.2%	$ 31,374	13.8%

(1) With the approval of the Idaho and Washington general rate cases in 2021, a change in tax methodology resulted in recognizing a flow through benefit related to meters and mixed service costs.

(2) In March 2020, the WUTC approved an all-party settlement agreement related to electric tax benefits that were set aside for Colstrip in the 2020 general rate case order. In the approved settlement agreement, the parties agreed to utilize $10.9 million ($8.4 million when tax-effected) of the electric benefits to offset costs associated with accelerating the depreciation of Colstrip Units, to reflect a remaining useful life through December 31, 2025. In the second quarter of 2020, the Company recorded a one-time increase to depreciation expense with an offsetting decrease to income tax expense.

In March 2019, the IPUC approved an all-party settlement agreement related to electric tax benefits that were set aside for Colstrip in the 2020 general rate case order. In the approved settlement agreement, the parties agreed to utilize $6.4 million ($5.1 million when tax-effected) of the electric benefits to offset costs associated with accelerating the depreciation of Colstrip, to reflect a remaining useful life through December 31, 2027. In the second quarter of 2019, the Company recorded a one-time increase to depreciation expense with an offsetting decrease to income tax expense.

Deferred Income Taxes

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes and tax credit carryforwards.

The total net deferred income tax liability consisted of the following as of December 31 (dollars in thousands):

	2021	2020
Deferred income tax assets:		
Regulatory liabilities	$ 200,513	$ 179,871
Tax credits and NOL carryforwards	64,994	57,516
Provisions for pensions	25,650	37,501
Other	38,181	42,641
Total gross deferred income tax assets	329,338	317,529
Valuation allowances for deferred tax assets	(9,626)	(10,021)
Total deferred income tax assets after valuation allowances	319,712	307,508
Deferred income tax liabilities:		
Utility property, plant, and equipment	688,856	666,639
Regulatory assets	264,978	232,697
Other	8,587	2,884
Total deferred income tax liabilities	962,421	902,220
Net long-term deferred income tax liability	$ 642,709	$ 594,712

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, 2021, the Company had $17.1 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 $7.5 million of the state tax credits. As such, the Company has recorded a valuation allowance of $9.6 million against the state tax credit carryforwards and reflected the net amount of $7.5 million as an asset as of December 31, 2021. State tax credits expire from 2022 to 2035.

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 2017 are open for an IRS tax examination.

The Company also 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.

The Idaho State Tax Commission is currently reviewing tax years 2014 through 2017. All tax years after 2017 are open for examination in Idaho, Oregon, Montana and Alaska.

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

Note 13. Energy Purchase Contracts

The below discussion only relates to Avista Utilities. The sole energy purchase contract at AEL&P is a PPA for the Snettisham Hydroelectric Project and it is accounted for as a lease. AEL&P does not have any other significant operating agreements or contractual obligations. See Note 5 for further discussion of the Snettisham PPA.

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

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

	2021	2020	2019
Utility power resources	$ 431,199	$ 324,297	$ 376,769

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

	2022	2023	2024	2025	2026	Thereafter	Total
Power resources	$ 198,052	$ 187,552	$ 200,693	$ 193,877	$ 184,230	$ 1,888,038	$ 2,852,442
Natural gas resources	87,228	66,508	42,581	36,423	32,094	382,981	647,815
Total	$ 285,280	$ 254,060	$ 243,274	$ 230,300	$ 216,324	$ 2,271,019	$ 3,500,257

These energy purchase contracts were entered into as part of Avista Utilities' obligation to serve its retail electric and natural gas customers' energy requirements, including contracts entered into for resource optimization. As a result, 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 above future contractual commitments for power resources include fixed contractual amounts related to the Company's contracts with certain PUDs to purchase portions of the output of certain generating facilities. Although Avista Utilities has no investment in the PUD generating facilities, the fixed contracts obligate Avista Utilities to pay certain minimum amounts whether or not the facilities are operating. The cost of power obtained under the contracts, including payments made when a facility is not operating, is included in utility resource costs in the Consolidated Statements of Income. The contractual amounts included above consist of Avista Utilities' share of existing debt service cost and its proportionate share of the variable operating expenses of these projects. The minimum amounts payable under these contracts are based in part on the proportionate share of the debt service requirements of the PUD's revenue bonds for which the Company is indirectly responsible. The Company's total future debt service obligation associated with the revenue bonds outstanding at December 31, 2021 (principal and interest) was $278.3 million.

In addition, Avista Utilities has operating agreements, settlements and other contractual obligations related to its generating facilities and transmission and distribution services. The expenses associated with these agreements are reflected as other operating expenses in the Consolidated Statements of Income.

The following table details future contractual commitments under these agreements (dollars in thousands):

	2022	2023	2024	2025	2026	Thereafter	Total
Contractual obligations	$ 28,912	$ 29,680	$ 30,471	$ 31,287	$ 32,127	$ 212,852	$ 365,329

Note 14. Committed Lines of Credit

Avista Corp.

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million. In June 2021, the Company entered into an amendment to its committed line of credit that extends the expiration date to June 2026, with the option to extend 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.

The committed line of credit agreement contains customary covenants and default provisions. The credit agreement has 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, 2021, the Company was in compliance with this covenant.

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

	2021	2020
Balance outstanding at end of period	$ 284,000	$ 102,000
Letters of credit outstanding at end of period	$ 34,000	$ 27,618
Average interest rate at end of period	1.11%	1.22%

As of December 31, 2021 and 2020, the borrowings outstanding under Avista Corp.'s committed line of credit were classified as short-term borrowings on the Consolidated Balance Sheets.

AEL&P

AEL&P has a committed line of credit in the amount of $25.0 million that expires in November 2024. The committed line of credit is secured by non-transferable first mortgage bonds of AEL&P issued to the agent bank that would only become due and payable in the event, and then only to the extent, that AEL&P defaults on its obligations under the committed line of credit.

The committed line of credit agreement contains customary covenants and default provisions. The credit agreement has a covenant which does not permit the ratio of "consolidated total debt at AEL&P" to "consolidated total capitalization at AEL&P," including the impact of the Snettisham bonds to be greater than 67.5 percent at any time. As of December 31, 2021, AEL&P was in compliance with this covenant.

As of December 31, 2021, there were no borrowings under the AEL&P committed line of credit. As of December 31, 2020, there was $1.0 million outstanding with an average interest rate of 1.65 percent.

Note 15. Credit Agreement

In April 2020, the Company entered into a Credit Agreement with various financial institutions, in the amount of $100 million. The Company borrowed the entire $100 million available under this agreement in April 2020 and repaid the outstanding balance in April 2021.

Note 16. Long-Term Debt

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

Maturity Year	Description	Interest Rate	2021	2020
Avista Corp. Secured Long-Term Debt				
2022	First Mortgage Bonds	5.13%	250,000	250,000
2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (1)	(1)	66,700	66,700
2034	Secured Pollution Control Bonds (1)	(1)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
2040	First Mortgage Bonds	5.55%	35,000	35,000
2041	First Mortgage Bonds	4.45%	85,000	85,000
2044	First Mortgage Bonds	4.11%	60,000	60,000
2045	First Mortgage Bonds	4.37%	100,000	100,000
2047	First Mortgage Bonds	4.23%	80,000	80,000
2047	First Mortgage Bonds	3.91%	90,000	90,000
2048	First Mortgage Bonds	4.35%	375,000	375,000
2049	First Mortgage Bonds	3.43%	180,000	180,000
2050	First Mortgage Bonds	3.07%	165,000	165,000
2051	First Mortgage Bonds	3.54%	175,000	175,000
2051	First Mortgage Bonds (2)	2.90%	140,000	—
	Total Avista Corp. secured long-term debt		2,157,200	2,017,200
Alaska Electric Light and Power Company Secured Long-Term Debt				
2044	First Mortgage Bonds	4.54%	75,000	75,000
	Total secured long-term debt		2,232,200	2,092,200
Alaska Energy and Resources Company Unsecured Long-Term Debt				
2024	Unsecured Term Loan	3.44%	15,000	15,000
	Total secured and unsecured long-term debt		2,247,200	2,107,200
Other Long-Term Debt Components				
	Unamortized debt discount		(632)	(710)
	Unamortized long-term debt issuance costs		(14,498)	(14,256)
	Total		2,232,070	2,092,234
	Secured Pollution Control Bonds held by Avista Corporation (1)		(83,700)	(83,700)
	Current portion of long-term debt		(250,000)	—
	Total long-term debt		$ 1,898,370	$ 2,008,534

(1) In December 2010, $66.7 million and $17.0 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) due in 2032 and 2034, respectively, which had been held by Avista Corp. since 2008 and 2009, respectively, were refunded by new variable rate bond issues (Series 2010A and Series 2010B). The new bonds were not offered to the public and were purchased by Avista Corp. due to market conditions. The Company expects that at a later date, subject to market conditions, these bonds may be remarketed to unaffiliated investors. So long as Avista Corp. is the holder of these bonds, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Consolidated Balance Sheets.

(2) In September 2021, the Company issued and sold $70.0 million of 2.90 percent first mortgage bonds due in 2051 pursuant to a bond purchase agreement with institutional investors in the private placement market. In December 2021, the Company issued and sold the remaining $70.0 million of bonds pursuant to the same agreement. The total net proceeds from the sale of the bonds were used to repay a portion of the outstanding balance under Avista Corp.'s $400.0 million committed line of credit. In connection with the pricing of the first mortgage bonds in September 2021, the Company cash settled four interest rate swap derivatives (notional aggregate amount of $45.0 million) and paid a net amount of $17.2 million. See Note 7 for a discussion of interest rate swap derivatives.

The following table details future long-term debt maturities including long-term debt to affiliated trusts (see Note 17) (dollars in thousands):

	2022	2023	2024	2025	2026	Thereafter	Total
Debt maturities	$ 250,000	$ 13,500	$ 15,000	$ —	$ —	$ 1,936,547	$ 2,215,047

Substantially all of Avista Utilities' and AEL&P'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 Utilities and AEL&P may each issue additional first mortgage bonds under their specific mortgage in an aggregate principal amount equal to the sum of:

- $66\frac{2}{3}$ percent of the cost or fair value (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 Utilities and AEL&P 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, 2021, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.8 billion in an aggregate principal amount of additional first mortgage bonds at Avista Utilities and $38.2 million by AEL&P, at an assumed interest rate of 8 percent in each case.

Note 17. Long-Term Debt to Affiliated Trusts

In 1997, the Company issued Floating Rate Junior Subordinated Deferrable Interest Debentures, Series B, with a principal amount of $51.5 million to Avista Capital II, an affiliated business trust formed by the Company. Avista Capital II issued $50.0 million of Preferred Trust Securities with a floating distribution rate of LIBOR plus 0.875 percent, calculated and reset quarterly.

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

	2021	2020	2019
Low distribution rate	0.99%	1.10%	2.79%
High distribution rate	1.10%	2.79%	3.61%
Distribution rate at the end of the year	1.05%	1.10%	2.79%

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

The Company owns 100 percent of Avista Capital II and has solely and unconditionally guaranteed the payment of distributions on, and redemption price and liquidation amount for, the Preferred Trust Securities to the extent that 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. The Company does not include these capital trusts in its consolidated financial statements as Avista Corp. is not the primary beneficiary. As such, the sole assets of the capital trusts are $51.5 million of junior subordinated deferrable interest debentures of Avista Corp., which are reflected on the Consolidated Balance Sheets. Interest expense to affiliated trusts in the Consolidated Statements of Income represents interest expense on these debentures.

Note 18. Fair Value

The carrying values of cash and cash equivalents, accounts and notes receivable, accounts payable and short-term borrowings are reasonable estimates of their fair values. Long-term debt (including current portion), finance leases, and long-term debt to affiliated trusts are reported at carrying value on the Consolidated Balance Sheets.

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

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

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

Level 2—Pricing inputs are other than quoted prices in active markets included in Level 1, but which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are 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 that are generally unobservable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

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

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

	2021		2020	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 963,500	$ 1,157,651	$ 963,500	$ 1,189,824
Long-term debt (Level 3)	1,200,000	1,366,619	1,060,000	1,235,248
Snettisham finance lease obligation (Level 3)	48,815	54,000	51,750	58,700
Long-term debt to affiliated trusts (Level 3)	51,547	43,299	51,547	43,815

These estimates of fair value of long-term debt and long-term debt to affiliated trusts were primarily based on available market information, which generally consists of estimated market prices from third-party brokers for debt with similar risk and terms. The price ranges obtained from the third-party brokers consisted of par values of 84.0 to 140.27, where a par value of 100.00 represents the carrying value recorded on the Consolidated Balance Sheets. Level 2 long-term debt represents publicly issued bonds with quoted market prices; however, due to their limited trading activity, they are classified as Level 2 because brokers must generate quotes and make estimates using comparable debt with similar risk and terms if there is no trading activity near a period end. Level 3 long-term debt consists of private placement bonds and debt to affiliated trusts, which typically have no secondary trading activity. Fair values in Level 3 are estimated based on market prices from third-party brokers using secondary market quotes for debt with similar risk and terms to generate quotes for Avista Corp. bonds. Due to the unique nature of the Snettisham finance lease obligation, the estimated fair value of these items was determined based on a discounted cash flow model using available market information. The Snettisham finance lease obligation was discounted to present value using the Morgan Markets A Ex-Fin discount rate as published on December 31, 2021.

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Consolidated Balance Sheets as of December 31, 2021 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting [1]	Total
December 31, 2021					
Assets:					
Energy commodity derivatives	$ —	$ 34,119	$ —	$ (31,211)	$ 2,908
Level 3 energy commodity derivatives:					
Natural gas exchange agreements	—	—	143	(143)	—
Interest rate swap derivatives	—	2,319	—	(1,170)	1,149
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities [2]	1,809	—	—	—	1,809
Equity securities [2]	7,594	—	—	—	7,594
Total	$ 9,403	$ 36,438	$ 143	$ (32,524)	$ 13,460
Liabilities:					
Energy commodity derivatives	$ —	$ 41,733	$ —	$ (40,300)	$ 1,433
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	7,914	(143)	7,771
Foreign currency exchange derivatives	—	19	—	—	19
Interest rate swap derivatives	—	25,274	—	(1,170)	24,104
Total	$ —	$ 67,026	$ 7,914	$ (41,613)	$ 33,327

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Consolidated Balance Sheets as of December 31, 2020 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting [1]	Total
December 31, 2020					
Assets:					
Energy commodity derivatives	$ —	$ 23,645	$ —	$ (22,152)	$ 1,493
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	75	(75)	—
Foreign currency exchange derivatives	—	30	—	—	30
Interest rate swap derivatives	—	952	—	(952)	—
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities [2]	2,471	—	—	—	2,471
Equity securities [2]	6,228	—	—	—	6,228
Total	$ 8,699	$ 24,627	$ 75	$ (23,179)	$ 10,222
Liabilities:					
Energy commodity derivatives	$ —	$ 23,030	$ —	$ (22,768)	$ 262
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	8,485	(75)	8,410
Interest rate swap derivatives	—	51,765	—	(9,002)	42,763
Total	$ —	$ 74,795	$ 8,485	$ (31,845)	$ 51,435

(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 any payables and receivables for cash collateral held or placed with these same counterparties.

(2) These assets are included in other property and investments—net and other non-current assets on the Consolidated Balance Sheets.

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 Consolidated Balance Sheets is due to netting arrangements with certain counterparties. See Note 7 for additional discussion of derivative netting.

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

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

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

Deferred compensation assets and liabilities represent funds held by the Company in a Rabbi Trust for an executive deferral plan. These funds consist of actively traded equity and bond funds with quoted prices in active markets. The balance disclosed in the table above excludes cash and cash equivalents of $0.1 million as of December 31, 2021 and $0.5 million as of December 31, 2020.

Level 3 Fair Value

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

The following table presents the quantitative information which was used to estimate the fair values of the Level 3 assets and liabilities above as of December 31, 2021 (dollars in thousands):

	Fair Value (Net) at December 31, 2021	Valuation Technique	Unobservable Input	Range
Natural gas exchange	(7,771)	Internally derived	Forward purchase prices	\$2.35–\$4.08/mmBTU
		weighted-average		\$2.96 Weighted-Average
		cost of gas	Forward sales prices	\$2.38–\$9.50/mmBTU
				\$4.51 Weighted-Average
			Purchase volumes	130,000–310,000 mmBTUs
			Sales volumes	25,000–310,000 mmBTUs

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

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

	Natural Gas Exchange Agreement	Power Exchange Agreement	Total
Year ended December 31, 2021:			
Balance as of January 1, 2021	\$ (8,410)	\$ —	\$ (8,410)
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets (1)	4,292	—	4,292
Settlements	(3,653)	—	(3,653)
Ending balance as of December 31, 2021 (2)	\$ (7,771)	\$ —	\$ (7,771)
Year ended December 31, 2020:			
Balance as of January 1, 2020	\$ (2,976)	\$ —	\$ (2,976)
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets (1)	(4,311)	—	(4,311)
Settlements	(1,123)	—	(1,123)
Ending balance as of December 31, 2020 (2)	\$ (8,410)	\$ —	\$ (8,410)
Year ended December 31, 2019:			
Balance as of January 1, 2019	\$ (2,774)	\$ (2,488)	\$ (5,262)
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets (1)	8,175	435	8,610
Settlements	(8,377)	2,053	(6,324)
Ending balance as of December 31, 2019 (2)	\$ (2,976)	\$ —	\$ (2,976)

(1) All gains and losses are included in other regulatory assets and liabilities. There were no gains and losses included in either net income or other comprehensive income during any of the periods presented in the table above.

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

Nonrecurring Fair Value Measurements

The Company holds equity investments without a readily determinable fair value, and these assets are recorded at fair value and adjusted on a nonrecurring basis as a result of observable changes in fair value using the measurement alternative.

Amounts recognized in the consolidated financial statements related to equity investments without readily determinable fair value include the following (dollars in thousands):

	December 31, 2021	December 31, 2020
Carrying Value (1)	$ 24,161	$ 15,110
Gains (losses)	8,761	925

(1) Carrying value is adjusted to fair value as of the measurement date when observable changes in fair value occur, such as a transaction involving the underlying asset. These assets are measured using a market approach and are level 2 assets.

Note 19. Common Stock

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

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

The requirements of the OPUC approval of the AERC acquisition are the most restrictive. Under the OPUC restriction, the amount available for dividends at December 31, 2021 was $322.3 million.

See the Consolidated Statements of Equity for dividends declared in the years 2019 through 2021.

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2021 and 2020.

Common Stock Issuances

The Company issued common stock in 2021 for total net proceeds of $90.0 million. Most of these issuances came through the Company's sales agency agreements under which the sales agents may offer and sell new shares of common stock from time-to-time. The Company has board and regulatory authority to issue a maximum of 4.3 million shares under these agreements, of which 2.1 million remain unissued as of December 31, 2021. In 2021, 2.2 million shares were issued under these agreements resulting in total net proceeds of $88.5 million.

Note 20. Accumulated Other Comprehensive Loss

Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss, net of tax, consisted of the following as of December 31 (dollars in thousands):

	2021	2020
Unfunded benefit obligation for pensions and other postretirement benefit plans—net of taxes of $2,934 and $3,822, respectively	$ 11,039	$ 14,378

The following table details the reclassifications out of accumulated other comprehensive loss by component for the years ended December 31 (dollars in thousands):

Details about Accumulated Other Comprehensive Loss Components (Affected Line Item in Statement of Income)	Amounts Reclassified from Accumulated Other Comprehensive Loss 2021	2020	2019
Amortization of defined benefit pension items			
Amortization of net prior service cost [a]	$ (793)	$ (794)	$ (794)
Amortization of net loss [a]	38,070	5,586	17,074
Adjustment due to effects of regulation [a]	(33,050)	(10,006)	(19,309)
Total before tax [b]	4,227	(5,214)	(3,029)
Tax expense [b]	(888)	1,095	636
Net of tax [b]	$ 3,339	$ (4,119)	$ (2,393)

(a) These accumulated other comprehensive loss components are included in the computation of net periodic pension cost (see Note 11 for additional details).

(b) Description is also the affected line item on the Consolidated Statements of Income

Note 21. Earnings Per Common Share Attributable to Avista Corporation Shareholders

The following table presents the computation of basic and diluted earnings per common share attributable to Avista Corp. shareholders for the years ended December 31 (in thousands, except per share amounts):

	2021	2020	2019
Numerator:			
Net income attributable to Avista Corp. shareholders	$ 147,334	$ 129,488	$ 196,979
Denominator:			
Weighted-average number of common shares outstanding—basic	69,951	67,962	66,205
Effect of dilutive securities:			
Performance and restricted stock awards	134	140	124
Weighted-average number of common shares outstanding—diluted	70,085	68,102	66,329
Earnings per common share attributable to Avista Corp. Shareholders:			
Basic	$ 2.11	$ 1.91	$ 2.98
Diluted	$ 2.10	$ 1.90	$ 2.97

There were no shares excluded from the calculation because they were antidilutive.

Note 22. 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 intends to vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the ultimate outcome of any particular matter because litigation and other contested proceedings are inherently subject to numerous uncertainties. For matters that affect Avista Utilities' or AEL&P's operations, the Company intends to seek, to the extent appropriate, recovery of incurred costs through the ratemaking process.

Collective Bargaining Agreements

The Company's collective bargaining agreement with the IBEW represents approximately 40 percent of all of Avista Utilities' employees. The Company's largest represented group, representing approximately 90 percent of Avista Utilities' bargaining unit employees in Washington and Idaho, were covered under a three-year agreement which expired in March 2021.

The Company is in the process of negotiating a new agreement with the IBEW. However, there is a risk that if a new agreement is not reached, employees subject to that agreement could strike. Given the number of employees that are covered by the collective bargaining agreement, a strike could result in disruptions to the Company's operations. However, the Company believes that the possibility of this occurring is remote.

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

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

The lawsuits were filed in the Superior Court of Ferry County, Washington. The Company continues to vigorously defend itself in the litigation. However, the Company cannot predict the outcome of these matters.

Labor Day Windstorm

General

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

The Company has become aware of instances where, during the course of the storm, otherwise healthy trees and limbs, located in areas outside its maintenance right-of-way, broke under the extraordinary wind conditions and caused damage to its energy delivery system at or near what is believed to be the potential area of origin of a wildfire. Those instances include what has been referred to as: the Babb Road Fire (near Malden and Pine City, Washington); the Christensen Road fire (near Airway Heights, Washington); and the Mile Marker 49 fire (near Orofino, Idaho). These wildfires covered, in total, approximately 22,000 acres. The Company currently estimates approximately 230 residential, commercial and other structures were impacted. With respect to the Christensen Road Fire and the Mile Marker 49 Fire, the Company's investigation determined that the primary cause of the fires was extreme high winds. To date, the Company has not found any evidence that the fires were caused by any deficiencies in its equipment, maintenance activities or vegetation management practices. See further discussion below regarding the Babb Road Fire.

In addition to the instances identified above, the Company is aware of a 5-acre fire that occurred in Colfax, Washington, which damaged several residential structures. The Company's investigation determined that the Company's facilities were not involved in the ignition of this fire.

The Company's investigation has found no evidence of negligence with respect to any of the fires, and the Company intends to vigorously defend any claims for damages that may be asserted against it with respect to the wildfires arising out of the extreme wind event.

Babb Road Fire

On May 14, 2021 the Company learned that the Washington Department of Natural Resources (DNR) had completed its investigation and issued a report on the Babb Road Fire. The Babb Road Fire covered approximately 15,000 acres and destroyed approximately 220 structures. There are no reports of personal injury or death resulting from the fire.

The DNR report concluded, among other things, that:

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

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

The DNR report acknowledged that, other than the multi-dominant nature of the tree, the conditions mentioned above would not have been easily visible without close-up inspection of, or cutting into, the tree. The report also acknowledged that, while the presence of multiple tops would have been visible from the nearby roadway, the tree did not fail at a v-fork due to the presence of multiple tops. The Company contends that applicable inspection standards did not require a closer inspection of the otherwise healthy tree, nor was the Company negligent with respect to its maintenance, inspection or vegetation management practices. The Company intends to vigorously defend any such assertion, if made. At this time, no material claims have been asserted against Avista Corp. for damages resulting from the Babb Road Fire.

Colstrip

Colstrip Owners Arbitration and Litigation

Colstrip Units 3 & 4 are jointly owned by the Company, PSE, Pacificorp, PGE (collectively, the "Western Co-Owners"), as well as NorthWestern and Talen, and are operated pursuant to an Ownership and Operating Agreement dated May 6, 1981, as amended (O&O Agreement). Avista Corp. is a 15 percent owner in Units 3 & 4. No single owner owns more than 30 percent of either generating unit.

The Washington CETA imposes deadlines by which coal-fired resources, such as Colstrip, must be excluded from the rate base of Washington utilities and by which electricity from such resources may no longer be delivered to Washington retail customers. The co-owners of Colstrip have differing needs for the generating capacity of these units. Accordingly, business disagreements have arisen among the co-owners, including, but not limited to, disagreements as to the shut-down date or dates of these units. These business disagreements, in turn, have led to disagreements as to the interpretation of the O&O Agreement, including, but not limited to, what percentage voting requirement under the O&O Agreement (55 percent vs. 100 percent) is needed to remove one or more of the Colstrip units from service or to make a determination that the project can no longer be operated consistent with prudent utility practice or the requirements of governmental agencies having jurisdiction. These disagreements are the subject of pending litigation in Montana Federal District Court in which the Western Co-Owners are plaintiffs and NorthWestern and Talen are defendants, as well as in the Montana District for Yellowstone County, in which Talen is the plaintiff and the Western Co-Owners and NorthWestern are defendants.

In addition, there are legal proceedings pending in Montana Federal District Court with respect to the validity and constitutionality of changes to Montana law enacted in 2021 after the foregoing disputes arose. The Western Co-Owners are plaintiffs in those proceedings and NorthWestern and Talen are defendants. The changes to Montana law at issue purport to (a) dictate the location of any arbitration under the O&O Agreement, overriding the express provisions of that agreement; and (b) define actions relating to closing or not operating Colstrip as violations of Montana's Consumer Protection Act. These legal proceedings remain pending.

The Company is not able to predict the outcome, nor an amount or range of potential impact in the event of an outcome that is adverse to the Company's interests. However, the Company will continue to vigorously defend and protect its interests (and those of its stakeholders) in all legal proceedings relating to Colstrip.

Burnett et al. v. Talen et al.

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

Westmoreland Mine Permits

Two lawsuits have been commenced by the Montana Environmental Information Center, challenging certain permits relating to the operation of the Westmoreland Rosebud Mine, which provides coal to Colstrip. The first, filed in the Montana District Court for Rosebud County, challenges the approval, by the Montana Board of Environmental Review, of a permit for mining what is designated as the "AM4" area of the mine, alleging procedural flaws in the approval process and substantive errors in its assessment of environmental impacts. On January 28, 2022, the Montana District Court for Rosebud County issued an order vacating the AM4 permit but deferring the annulment until April 1, 2022.

The second proceeding, filed in the Montana Federal District Court, challenged the Office of Surface Mining Reclamation and Enforcement's decision approving Westmoreland's expansion of the mine into what is designated as "Area F" on the grounds that it violated the National Environmental Protection Act and the Endangered Species Act. On February 11, 2022, a Magistrate Judge issued findings and recommended that approval decision be vacated but that the annulment be delayed for 365 days from the date of a final order.

Avista Corp. is not a party to either of these proceedings. Avista Corp. is continuing to monitor the progress of both lawsuits and assess the impact, if any, of the proceedings on Westmoreland's ability to meet its contractual coal supply obligations.

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

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

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

Rathdrum, Idaho Natural Gas Incident

In October 2021, there was an incident in Rathdrum, Idaho involving the Company's natural gas infrastructure. The incident occurred after a third party damaged those facilities during the course of excavation work. The incident resulted in a fire which destroyed one residence and resulted in minor injuries to the occupants. At this time, the Company is unable to predict the likelihood of a claim arising out of the matter, nor an amount or range of a potential loss, if any, in the event of such a claim.

Other Contingencies

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes that any ultimate liability arising from these actions will not have a material impact on its financial condition, results of operations or cash flows. It is possible that 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 State of Montana is examining the status of all water right claims within state boundaries through a general adjudication. Claims within the Clark Fork River basin could adversely affect the energy production of the Company's Cabinet Gorge and Noxon Rapids hydroelectric facilities. The state of Idaho has initiated adjudication in northern Idaho, which will ultimately include the lower Clark Fork River, the Spokane River and the Coeur d'Alene basin. The Company is and will continue to be a participant in these and any other relevant 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 23. Regulatory Matters

Regulatory Assets and Liabilities

The following table presents the Company's regulatory assets and liabilities as of December 31, 2021 (dollars in thousands):

	Remaining Amortization Period	Receiving Regulatory Treatment: Earning A Return [1]	Receiving Regulatory Treatment: Not Earning A Return	Expected Recovery or Refund [2]	2021 Current	2021 Non-current	2020 Current	2020 Non-Current
Regulatory Assets:								
Deferred income tax	[3]	$ 244,154	$ —	$ —	$ —	$ 244,154	$ —	$ 108,517
Pensions and other postretirement benifit plans	[4]	—	165,696	—	—	165,696	—	198,746
Energy commodity derivatives	[5]	—	15,385	—	12,447	2,938	2,073	5,722
Unamortized debt repurchase costs	[6]	6,768	—	—	—	6,768	—	7,512
Settlement with Coeur d'Alene Tribe	2059	38,926	—	—	—	38,926	—	40,043
Demand side management programs	[3]	—	3,974	—	—	3,974	—	3,814
Decoupling surcharge	2023	24,532	—	—	9,907	14,625	7,123	17,123
Utility plant to be abandoned	[7]	26,771	—	—	—	26,771	—	28,916
Interest rate swaps	[8]	158,082	—	41,672	—	199,754	—	214,851
Deferred power costs	[3]	10,835	—	—	7,334	3,501	1,775	1,562
Deferred natural gas costs	[3]	21,027	—	—	14,095	6,932	2,308	—
AFUDC above FERC allowed rate	[11]	48,455	—	—	—	48,455	—	47,393
COVID-19 deferrals	[12]	—	—	13,591	—	13,591	—	8,166
Advanced meter infrastructure	[13]	36,008	—	—	—	36,008	—	26,379
Other regulatory assets	[3]	37,045	8,563	2,925	—	48,533	394	41,699
Total regulatory assets		$ 652,603	$ 193,618	$ 58,188	$ 43,783	$ 860,626	$ 13,673	$ 750,443
Regulatory Liabilities:								
Deferred natural gas costs	[3]	$ —	$ —	$ —	$ —	$ —	$ 874	$ —
Deferred power costs	[3]	11,891	—	—	6,457	5,434	20,299	17,570
Utility plant retirement costs	[9]	350,190	—	—	—	350,190	—	325,832
Income tax related liabilities	[3] [10]	346,847	24,411	143,862	56,331	458,789	14,952	399,677
Interest rate swaps	[8]	13,589	—	1,473	—	15,062	—	15,046
Decoupling rebate	2022	9,308	—	—	3,049	6,259	1,447	1,519
COVID-19 deferrals	[12]	—	—	12,500	—	12,500	—	10,949
Other regulatory liabilities	[3]	6,905	17,688	—	11,312	13,281	8,863	14,227
Total regulatory liabilities		$ 738,730	$ 42,099	$ 157,835	$ 77,149	$ 861,515	$ 46,435	$ 784,820

(1) Earning a return includes either interest on the regulatory asset/liability or a return on the investment as a component of rate base at the allowed rate of return.

(2) Expected recovery is pending regulatory treatment including regulatory assets and liabilities with prior regulatory precedence.

(3) Remaining amortization period varies depending on timing of underlying transactions.

(4) As the Company has historically recovered and currently recovers its pension and other postretirement benefit costs related to its regulated operations in retail rates, the Company records a regulatory asset for that portion of its pension and other postretirement benefit funding deficiency.

(5) 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 losses result in adjustments to retail rates through PGAs, the ERM in Washington, the PCA mechanism in Idaho and periodic general rates cases. The resulting regulatory assets associated with energy commodity derivative instruments have been concluded to be probable of recovery through future rates.

(6) Premiums paid or discounts received to repurchase debt are amortized over the remaining life of the original debt that was repurchased or, if new debt is issued in connection with the repurchase, these costs are amortized over the life of the new debt. These costs are recovered through retail rates as a component of interest expense.

(7) The WUTC approved recovery of AMI project costs through the 2020 general rate case settlements, including amortization of retired meters replaced through the project through 2033. There are additional smaller projects included in the balance that the Company expects to fully recover, which have not yet been through the regulatory process.

(8) For interest rate swap derivatives, Avista Corp. records all mark-to-market gains and losses in each accounting period as assets and liabilities, as well as offsetting regulatory assets and liabilities, such that there is no income statement impact. The interest rate swap derivatives are risk management tools similar to energy commodity derivatives. Upon settlement of interest rate swap derivatives, the regulatory asset or liability is amortized as a component of interest expense over the term of the associated debt. The Company records an offset of interest rate swap derivative assets and liabilities with regulatory assets and liabilities, based on the prior practice of the commissions to provide recovery through the ratemaking process. Settled interest rate swap derivatives which have been through a general rate case proceeding are classified as earning a return in the table above, whereas all unsettled interest rate swap derivatives and settled interest rate swap derivatives which have not been included in a general rate case are classified as expected recovery.

(9) This amount is dependent upon the cost of removal of underlying utility plant assets and the life of utility plant.

(10) The majority of this balance represents amounts due back to customers and resulted from the Tax Cuts and Jobs Act signed into law in December 2017, which changed the federal income tax rate from 35 percent to 21 percent. The Company revalued all deferred income taxes as of December 31, 2017. The Company expects the amounts for utility plant items for Avista Utilities to be returned to customers over a period of approximately 32 years. The Company expects the AEL&P amounts to be returned to customers over a period of approximately 40 years. A significant portion of the regulatory liability attributable to non-plant excess deferred taxes was used to offset a portion of the costs associated with accelerating the depreciation of Colstrip based on settlements in Washington and Idaho.

(11) This amount is being amortized based on the underlying utility plant assets and the life of utility plant.

(12) The WUTC, IPUC and OPUC issued accounting orders allowing the Company to defer certain costs, net of any benefits, related to the COVID-19 pandemic. The Company has recorded all benefits on a gross basis as a regulatory liability to customers and all additional allowed costs are a regulatory asset. The ratemaking treatment will be determined in future general rate cases in each jurisdiction.

(13) This amount represents the deferral of the depreciation expense of the Company's AMI project in Washington state. Recovery of these amounts was approved by WUTC in the 2021 general rate case order.

Power Cost Deferrals and Recovery Mechanisms

Deferred power supply costs are recorded as a deferred charge or liability on the Consolidated 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 Utilities 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 Utilities 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 and defer these differences (over the $4.0 million deadband and sharing bands) for future surcharge or rebate to customers. For 2021, the Company recognized a pre-tax expense of $7.7 million under the ERM in Washington compared to a benefit of $6.2 million for 2020. Total net deferred power costs under the ERM were a liability of $11.9 million as of December 31, 2021 and a liability of $37.9 million as of December 31, 2020. These deferred power cost balances 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. As the cumulative rebate balance exceeded $30 million, the Company's 2019 filing contained a proposed rate refund. The ERM proceeding was considered with the Company's 2019 general rate case proceeding and a refund was approved and is being returned to customers over a two-year period that began on April 1, 2020. Avista Utilities 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.

Avista Utilities has a PCA mechanism in Idaho that allows it to modify electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, Avista Utilities 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 an asset of $10.8 million as of December 31, 2021 and $2.5 million as of December 31, 2020. Deferred power cost assets represent amounts due from customers and liabilities represent amounts due to customers.

Natural Gas Cost Deferrals and Recovery Mechanisms

Avista Utilities 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. Total net deferred natural gas costs were an asset of $21.0 million as of December 31, 2021 and $1.4 million as of December 31, 2020. Asset balances represent amounts due from customers and liabilities represent amounts due to customers.

Decoupling and Earnings Sharing Mechanisms

Decoupling (also known as an FCA in Idaho) is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. In each of Avista Utilities' jurisdictions, Avista Utilities' 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 for a five-year period beginning January 1, 2015. In 2019, the WUTC approved an extension of the mechanisms for an additional five-year term through March 31, 2025, with one modification in that new customers added after any test period would not be decoupled until included in a future test period.

Electric and natural gas decoupling surcharge rate adjustments to customers are limited to a 3 percent increase on an annual basis, with any remaining surcharge balance carried forward for recovery in a future period. There is no limit on the level of rebate rate adjustments.

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. If the Company earns more than its authorized ROR in Washington, 50 percent of excess earnings are rebated to customers through adjustments to decoupling surcharge or rebate balances. See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

The Company has proposed to modify this earnings test in its 2022 general rate case, so that if the Company earns more than 0.5 percent higher than the ROR authorized by the WUTC in the multi-year rate plan, the Company would defer these excess revenues and later return them to customers.

Idaho FCA and Earnings Sharing Mechanisms

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

Oregon Decoupling Mechanism

In Oregon, the Company has a decoupling mechanism for natural gas. An earnings review is conducted on an annual basis. In the annual earnings review, if the Company earns more than 100 basis points above its allowed ROE, 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, 2021 and December 31, 2020, the Company had the following cumulative balances outstanding related to decoupling and earnings sharing mechanisms in its various jurisdictions (dollars in thousands):

	2021	2020
Washington		
Decoupling surcharge	$ 13,522	$ 21,340
Idaho		
Decoupling (rebate) surcharge	$ (1,450)	$ 1,202
Provision for earnings sharing rebate	(686)	(686)
Oregon		
Decoupling surcharge (rebate)	$ 3,152	$ (1,262)

There were no earnings sharing rebates associated with Washington and Oregon as of December 31, 2021 and December 31, 2020.

Note 24. Information by Business Segments

The business segment presentation reflects the basis used by the Company's management to analyze performance and determine the allocation of resources. The Company's management evaluates performance based on income (loss) from operations before income taxes as well as net income (loss) attributable to Avista Corp. shareholders. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. Avista Utilities' business is managed based on the total regulated utility operation; therefore, it is considered one segment. AEL&P is a separate reportable business segment as it has separate financial reports that are reviewed in detail by the Chief Operating Decision Maker and its operations and risks are sufficiently different from Avista Utilities and the other businesses at AERC that it cannot be aggregated with any other operating segments. The Other category, which is not a reportable segment, includes other investments and operations of various subsidiaries, as well as certain other operations of Avista Capital.

The following table presents information for each of the Company's business segments (dollars in thousands):

	Avista Utilities	Alaska Electric Light and Power Company	Total Utility	Other	Intersegment Eliminations (1)	Total
For the year ended December 31, 2021:						
Operating revenues	$ 1,392,999	$ 45,366	$ 1,438,365	$ 571	$ —	$ 1,438,936
Resource costs	493,289	3,834	497,123	—	—	497,123
Other operating expenses	352,241	13,884	366,125	5,927	—	372,052
Depreciation and amortization	221,552	10,363	231,915	261	—	232,176
Income (loss) from operations	217,663	16,186	233,849	(5,617)	—	228,232
Interest expense (2)	99,629	6,096	105,725	522	(95)	106,152
Income taxes	6,029	2,763	8,792	3,239	—	12,031
Net income from continuing operations attributable to Avista Corp. shareholders	125,558	7,224	132,782	14,552	—	147,334
Capital expenditures (3)	435,887	4,052	439,939	1,270	—	441,209
For the year ended December 31, 2020:						
Operating revenues	$ 1,277,468	$ 42,809	$ 1,320,277	$ 1,614	$ —	$ 1,321,891
Resource costs	396,543	1,966	398,509	—	—	398,509
Other operating expenses	341,709	12,905	354,614	5,344	—	359,958
Depreciation and amortization	213,701	9,806	223,507	716	—	224,223
Income (loss) from operations	220,058	17,088	237,146	(4,446)	—	232,700
Interest expense (2)	98,451	6,272	104,723	524	(186)	105,061
Income taxes	4,921	3,011	7,932	(881)	—	7,051
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	124,810	8,095	132,905	(3,417)	—	129,488
Capital expenditures (3)	397,292	7,014	404,306	1,368	—	405,674
For the year ended December 31, 2019:						
Operating revenues	$ 1,295,873	$ 37,265	$ 1,333,138	$ 12,484	$ —	$ 1,345,622
Resource costs	442,471	(2,654)	439,817	—	—	439,817
Other operating expenses (4)	352,170	12,717	364,887	18,883	—	383,770
Depreciation and amortization	195,697	9,668	205,365	629	—	205,994
Income (loss) from operations	200,994	16,423	217,417	(7,028)	—	210,389
Interest expense (2)	97,866	6,385	104,251	1,032	(929)	104,354
Income taxes	28,363	2,816	31,179	195	—	31,374
Net income from continuing operations attributable to Avista Corp. shareholders	183,977	7,458	191,435	5,544	—	196,979
Capital expenditures (3)	434,077	8,433	442,510	835	—	443,345
Total Assets:						
As of December 31, 2021	$ 6,458,244	$ 265,422	$ 6,723,666	$ 132,158	$ (2,241)	$ 6,853,583
As of December 31, 2020	$ 6,035,340	$ 268,971	$ 6,304,311	$ 109,658	$ (11,872)	$ 6,402,097
As of December 31, 2019	$ 5,713,268	$ 271,393	$ 5,984,661	$ 113,390	$ (15,595)	$ 6,082,456

(1) Intersegment eliminations reported as interest expense represent intercompany interest. Intersegment eliminations reported as assets represent intersegment accounts receivable.

(2) Including interest expense to affiliated trusts.

(3) The capital expenditures for the other businesses are included in other investing activities on the Consolidated Statements of Cash Flows.

(4) Other operating expenses for Avista Utilities for 2019 include merger transaction costs which are separately disclosed on the Consolidated Statements of Income.

Note 25. Termination of Proposed Acquisition by Hydro One

In July 2017, Avista Corp. entered into a Merger Agreement that provided for Avista Corp. to become an indirect, wholly owned subsidiary of Hydro One, subject to the satisfaction or waiver of specified closing conditions, including approval by regulatory agencies.

Termination of the Merger Agreement

Due to the denial of the proposed merger by certain of the Company's regulatory commissions, in January 2019, Avista Corp., Hydro One and certain subsidiaries thereof, entered into a Termination Agreement indicating their mutual agreement to terminate the Merger Agreement. Pursuant to the terms of the Termination Agreement, Hydro One paid Avista Corp. a $103 million termination fee in January 2019. The termination fee was used for reimbursing the Company's transaction costs incurred from 2017 to 2019. The balance of the termination fee remaining after payment of 2019 transaction costs and applicable income taxes was used for general corporate purposes and reduced the Company's need for external financing. The 2019 costs were $19.7 million pre-tax and included financial advisers' fees, legal fees, consulting fees and employee time.

Note 26. Sale of METALfx

In April 2019, Bay Area Manufacturing, Inc., a non-regulated subsidiary of Avista Corp., entered into a definitive agreement to sell its interest in METALfx to an independent third party. The transaction was a stock sale for a total cash purchase price of $17.5 million, plus cash on-hand, subject to customary closing adjustments. The transaction closed in April 2019, and as of that date the Company has no further involvement with METALfx.

The purchase price of $17.5 million, as adjusted, was divided among the security holders of METALfx, including the minority shareholder, pro-rata based on ownership (Avista Corp. owned 89.2 percent of the equity of METALfx).

The sales transaction provided cash proceeds to Avista Corp., net of payments to the minority holder, contractually obligated compensation payments and other transaction expenses, of $16.5 million and resulted in a net gain after-tax of $3.3 million. The gross gain is included in "Other income," the transaction expenses paid are included in "Non-utility Other operating expenses" and any taxes associated with the sale are included in "Income tax expense" on the Consolidated Statements of Income.

Prior to the completion of the sales transaction, METALfx was not a reportable business segment and was included in Other in the business segment footnote at Note 24. This transaction does not meet the criteria for discontinued operations as it does not represent a strategic shift that will have a major effect on the Company's ongoing operations.

Item 9. Changes In and Disagreements With Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

The Company has disclosure controls and procedures (as defined in Rules 13a–15(e) and 15d–15(e) under the Securities Exchange Act of 1934, as amended (Act) that are designed to ensure that information required to be disclosed in the reports it files or submits under the Act is recorded, processed, summarized and reported on a timely basis. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Act is accumulated and communicated to the Company's management, including its principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. With the participation of the Company's principal executive officer and principal financial officer, the Company's management evaluated its disclosure controls and procedures as of the end of the period covered by this report. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures are effective at a reasonable assurance level as of December 31, 2021.

Management's Report on Internal Control Over Financial Reporting

The Company's management, together with its consolidated subsidiaries, is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a–15(f) under the Securities Exchange Act of 1934). The Company's internal control over financial reporting is a process designed under the supervision of the Company's principal executive officer and principal financial officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with accounting principles generally accepted in the United States of America.

The Company's internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets; provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of the Company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the Company's financial statements.

Under the supervision and with the participation of the Company's management, including the Company's principal executive officer and principal financial officer, the Company conducted an assessment of the effectiveness of the Company's internal control over financial reporting based on the framework established in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management determined that the Company's internal control over financial reporting as of December 31, 2021 is effective at a reasonable assurance level.

The Company's independent registered public accounting firm, Deloitte & Touche LLP, has issued an attestation report on the Company's internal control over financial reporting as of December 31, 2021.

Changes in Internal Control Over Financial Reporting

There have been no changes in the Company's internal control over financial reporting that occurred during the Company's last fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Report of Independent Registered Public Accounting Firm

To the shareholders and the Board of
Directors of Avista Corporation

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Avista Corporation and subsidiaries (the "Company") as of December 31, 2021, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2021, of the Company and our report dated February 22, 2022, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 22, 2022

Item 9B. Other Information

None.

Item 9C. Disclosure Regarding Foreign Jurisdictions That Prevent Inspections

Not applicable.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this Item (other than the information regarding executive officers and the Company's Code of Business Conduct and Ethics set forth below) is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 12, 2022, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2021, relating to its Annual Meeting of Shareholders held on May 11, 2021.

Information about our Executive Officers

Name	Age	Business Experience
Dennis P. Vermillion	60	Chief Executive Officer since October 2019; President of Avista Corp since January 2018; Director since January 2018; Senior Vice President from January 2010–January 2018; Vice President July 2007–December 2009; President—Avista Utilities since January 2009; Vice President of Energy Resources and Optimization—Avista Utilities July 2007–December 2008; President and Chief Operating Officer of Avista Energy February 2001–July 2007; various other management and staff positions with the Company since 1985.
Mark T. Thies	58	Executive Vice President since October 2019; Treasurer since January 2013; Chief Financial Officer since September 2008; Senior Vice President from September 2008–October 2019; prior to employment with the Company held the following positions with Black Hills Corporation: Executive Vice President and Chief Financial Officer March 2003–January 2008; Senior Vice President and Chief Financial Officer March 2000–March 2003; Controller May 1997–March 2000.
Kevin J. Christie	54	Senior Vice President, External Affairs and Chief Customer Officer since October 2019; Vice President, External Affairs and Chief Customer Officer January 2018; Vice President of Customer Solutions February 2015–January 2018; various other management and staff positions with the Company since 2005.
Heather L. Rosentrater	44	Senior Vice President, Energy Delivery and Shared Services since January 2020; Senior Vice President, Energy Delivery from October 2019–December 2019; Vice President of Energy Delivery December 2015; various other management and staff positions with the Company since 1996.
Jason R. Thackston	52	Senior Vice President since January 2014; Environmental Compliance Officer since May 2018; Vice President of Energy Resources since December 2012; Vice President of Customer Solutions—Avista Utilities June 2012–December 2012; Vice President of Energy Delivery April 2011–December 2012; Vice President of Finance June 2009–April 2011; various other management and staff positions with the Company since 1996.
Bryan A. Cox	52	Vice President, Safety and Human Resources since January 2020; Vice President, Safety and HR Shared Services January 2018–January 2020; various other management and staff positions with the Company since 1997.

Gregory C. Hesler	44	Vice President, General Counsel, Corporate Secretary and Chief Ethics/Compliance Officer since May 2020; Vice President, General Counsel and Chief Compliance Officer January 2020–May 2020; various other management and staff positions with the Company since 2015.
Latisha D. Hill	43	Vice President of Community and Economic Vitality since January 2020; various other management and staff positions with the Company since 2005.
James M. Kensok	63	Vice President, Chief Information Officer and Chief Security Officer since January 2013; Vice President and Chief Information Officer January 2007–January 2013; Chief Information Officer February 2001–December 2006; various other management and staff positions with the Company since 1996.
Ryan L. Krasselt	52	Vice President, Controller and Principal Accounting Officer since October 2015; various other management and staff positions with the Company since 2001.
David J. Meyer	68	Vice President and Chief Counsel for Regulatory and Governmental Affairs since February 2004; Senior Vice President and General Counsel September 1998–February 2004.
Edward D. Schlect Jr.	61	Vice President and Chief Strategy Officer since September 2015; prior to employment with the Company, Executive Vice President of Corporate Development at Ecova, Inc.

All of the Company's executive officers, with the exception of David J. Meyer, Kevin J. Christie, and Heather L. Rosentrater, were officers or directors of one or more of the Company's subsidiaries in 2021. The Company's executive officers are appointed annually by the Board of Directors.

The Company has adopted a Code of Conduct for directors, officers (including the principal executive officer, principal financial officer and principal accounting officer), and employees. The Code of Conduct is available on the Company's website at www.avistacorp.com and will also be provided to any shareholder without charge upon written request to:

Avista Corp.
General Counsel
P.O. Box 3727 MSC-10
Spokane, Washington 99220-3727

Any changes to or waivers for executive officers and directors of the Company's Code of Conduct will be posted on the Company's website.

Item 11. Executive Compensation

The information required by this Item is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 12, 2022, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2021, relating to its Annual Meeting of Shareholders held on May 11, 2021.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

(a) Security ownership of certain beneficial owners (owning 5 percent or more of Registrant's voting securities):

Information regarding security ownership of certain beneficial owners (owning 5 percent or more of Registrant's voting securities) has been omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 12, 2022, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2021, relating to its Annual Meeting of Shareholders held on May 11, 2021; reference also being made to Schedules 13G, as amended, on file with the SEC with respect to the Registrant's voting securities (the information contained in such schedules 13G, as amended, not being incorporated herein by reference).

(b) Security ownership of management:

The information required by this Item regarding the security ownership of management is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 12, 2022, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2021, relating to its Annual Meeting of Shareholders held on May 11, 2021.

(c) Changes in control:

None.

(d) Securities authorized for issuance under equity compensation plans as of December 31, 2021:

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights [(1)]	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders [(2)]	—	$ —	1,130,521

(1) Excludes unvested restricted shares and performance share awards granted under Avista Corp.'s Long-Term Incentive Plan. At December 31, 2021, 96,127 Restricted Share awards were outstanding. Performance and market-based share awards may be paid out at zero shares at a minimum achievement level; 215,708 shares at target level; or 431,416 shares at a maximum level. Because there is no exercise price associated with restricted shares or performance and market-based share awards, such shares are not included in the weighted-average price calculation.

(2) Includes the Long-Term Incentive Plan approved by shareholders in 1998 (amended in 2016) and the Non-Employee Director Stock Plan approved by shareholders in 1996. In February 2005, the Board of Directors elected to terminate the Non-Employee Director Stock Plan.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this Item is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 12, 2022, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2021, relating to its Annual Meeting of Shareholders held on May 11, 2021.

Item 14. Principal Accounting Fees and Services

The information required by this Item is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 12, 2022, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2021, relating to its Annual Meeting of Shareholders held on May 11, 2021.

Part IV

Item 15. Exhibits, Financial Statement Schedules

(a) 1. Financial Statements (Included in Part II of this report):

Report of Independent Registered Public Accounting Firm

Consolidated Statements of Income for the Years Ended December 31, 2021, 2020 and 2019

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2021, 2020 and 2019

Consolidated Balance Sheets as of December 31, 2021 and 2020

Consolidated Statements of Cash Flows for the Years Ended December 31, 2021, 2020 and 2019

Consolidated Statements of Equity for the Years Ended December 31, 2021, 2020 and 2019

Notes to Consolidated Financial Statements

(a) 2. Financial Statement Schedules:

None.

(a) 3. Exhibits:

Reference is made to the Exhibit Index commencing on the following page. The Exhibits include the management contracts and compensatory plans or arrangements required to be filed as exhibits to this Form 10-K pursuant to Item 15(b).

Exhibit Index

Exhibit	Previously Filed (1) With Registration Number	Previously Filed (1) As Exhibit	
2.1	(with Form 8-K filed as of July 19, 2017)	2.1	Agreement and Plan of Merger, dated as of July 19, 2017, by and among Avista Corporation, Hydro One Limited, Olympus Holding Corp. and Olympus Corp.
2.2	(with Form 8-K filed as of January 23, 2019)	2.1	Termination Agreement, dated as of January 23, 2019, by and among Avista Corporation, Hydro One Limited, Olympus Holding Corp. and Olympus Corp.
3.1	(with June 30, 2012 Form 10-Q)	3.1	Restated Articles of Incorporation of Avista Corporation, as amended and restated June 6, 2012.
3.2	(with Form 8-K filed as of August 17, 2016)	3.2	Bylaws of Avista Corporation, as amended August 17, 2016.
4.1	2-4077	B-3	Mortgage and Deed of Trust, dated as of June 1, 1939.*
4.2	2-9812	4(c)	First Supplemental Indenture, dated as of October 1, 1952.*
4.3	2-60728	2(b)-2	Second Supplemental Indenture, dated as of May 1, 1953.*
4.4	2-13421	4(b)-3	Third Supplemental Indenture, dated as of December 1, 1955.*
4.5	2-13421	4(b)-4	Fourth Supplemental Indenture, dated as of March 15, 1967.*
4.6	2-60728	2(b)-5	Fifth Supplemental Indenture, dated as of July 1, 1957.*
4.7	2-60728	2(b)-6	Sixth Supplemental Indenture, dated as of January 1, 1958.*
4.8	2-60728	2(b)-7	Seventh Supplemental Indenture, dated as of August 1, 1958.*
4.9	2-60728	2(b)-8	Eighth Supplemental Indenture, dated as of January 1, 1959.*
4.10	2-60728	2(b)-9	Ninth Supplemental Indenture, dated as of January 1, 1960.*
4.11	2-60728	2(b)-10	Tenth Supplemental Indenture, dated as of April 1, 1964.*
4.12	2-60728	2(b)-11	Eleventh Supplemental Indenture, dated as of March 1, 1965.*
4.13	2-60728	2(b)-12	Twelfth Supplemental Indenture, dated as of May 1, 1966.*
4.14	2-60728	2(b)-13	Thirteenth Supplemental Indenture, dated as of August 1, 1966.*
4.15	2-60728	2(b)-14	Fourteenth Supplemental Indenture, dated as of April 1, 1970.*
4.16	2-60728	2(b)-15	Fifteenth Supplemental Indenture, dated as of May 1, 1973.*
4.17	2-60728	2(b)-16	Sixteenth Supplemental Indenture, dated as of February 1, 1975.*
4.18	2-60728	2(b)-17	Seventeenth Supplemental Indenture, dated as of November 1, 1976.*
4.19	2-69080	2(b)-18	Eighteenth Supplemental Indenture, dated as of June 1, 1980.*
4.20	(with 1980 Form 10-K)	4(a)-20	Nineteenth Supplemental Indenture, dated as of January 1, 1981.*

Exhibit Index (continued)

Exhibit	Previously Filed[1] With Registration Number	As Exhibit	
4.21	2-79571	4(a)-21	Twentieth Supplemental Indenture, dated as of August 1, 1982.*
4.22	(with Form 8-K dated September 20, 1983)	4(a)-22	Twenty-First Supplemental Indenture, dated as of September 1, 1983.*
4.23	2-94816	4(a)-23	Twenty-Second Supplemental Indenture, dated as of March 1, 1984.*
4.24	(with 1986 Form 10-K)	4(a)-24	Twenty-Third Supplemental Indenture, dated as of December 1, 1986.*
4.25	(with 1987 Form 10-K)	4(a)-25	Twenty-Fourth Supplemental Indenture, dated as of January 1, 1988.*
4.26	(with 1989 Form 10-K)	4(a)-26	Twenty-Fifth Supplemental Indenture, dated as of October 1, 1989.*
4.27	33-51669	4(a)-27	Twenty-Sixth Supplemental Indenture, dated as of April 1, 1993.*
4.28	(with 1993 Form 10-K)	4(a)-28	Twenty-Seventh Supplemental Indenture, dated as of January 1, 1994.
4.29	(with 2001 Form 10-K)	4(a)-29	Twenty-Eighth Supplemental Indenture, dated as of September 1, 2001.
4.30	333-82502	4(b)	Twenty-Ninth Supplemental Indenture, dated as of December 1, 2001.
4.31	(with June 30, 2002 Form 10-Q)	4(f)	Thirtieth Supplemental Indenture, dated as of May 1, 2002.
4.32	333-39551	4(b)	Thirty-First Supplemental Indenture, dated as of May 1, 2003.
4.33	(with September 30, 2003 Form 10-Q)	4(f)	Thirty-Second Supplemental Indenture, dated as of September 1, 2003.
4.34	333-64652	4(a)33	Thirty-Third Supplemental Indenture, dated as of May 1, 2004.
4.35	(with Form 8-K dated as of December 15, 2004)	4.1	Thirty-Fourth Supplemental Indenture, dated as of November 1, 2004.
4.36	(with Form 8-K dated as of December 15, 2004)	4.2	Thirty-Fifth Supplemental Indenture, dated as of December 1, 2004.
4.37	(with Form 8-K dated as of December 15, 2004)	4.3	Thirty-Sixth Supplemental Indenture, dated as of December 1, 2004.
4.38	(with Form 8-K dated as of December 15, 2004)	4.4	Thirty-Seventh Supplemental Indenture, dated as of December 1, 2004.
4.39	(with Form 8-K dated as of May 12, 2005)	4.1	Thirty-Eighth Supplemental Indenture, dated as of May 1, 2005.
4.40	(with Form 8-K dated as of November 17, 2005)	4.1	Thirty-Ninth Supplemental Indenture, dated as of November 1, 2005.
4.41	(with Form 8-K dated as of April 6, 2006)	4.1	Fortieth Supplemental Indenture, dated as of April 1, 2006.
4.42	(with Form 8-K dated as of December 15, 2006)	4.1	Forty-First Supplemental Indenture, dated as of December 1, 2006.

Exhibit	Previously Filed [1] With Registration Number	As Exhibit	
4.43	(with Form 8-K dated as of April 3, 2008)	4.1	Forty-Second Supplemental Indenture, dated as of April 1, 2008.
4.44	(with Form 8-K dated as of November 26, 2008)	4.1	Forty-Third Supplemental Indenture, dated as of November 1, 2008.
4.45	(with Form 8-K dated as of December 16, 2008)	4.1	Forty-Fourth Supplemental Indenture, dated as of December 1, 2008.
4.46	(with Form 8-K dated as of December 30, 2008)	4.3	Forty-Fifth Supplemental Indenture, dated as of December 1, 2008.
4.47	(with Form 8-K dated as of September 15, 2009)	4.1	Forty-Sixth Supplemental Indenture, dated as of September 1, 2009.
4.48	(with Form 8-K dated as of November 25, 2009)	4.1	Forty-Seventh Supplemental Indenture, dated as of November 1, 2009.
4.49	(with Form 8-K dated as of December 15, 2010)	4.5	Forty-Eighth Supplemental Indenture, dated as of December 1, 2010.
4.50	(with Form 8-K dated as of December 20, 2010)	4.1	Forty-Ninth Supplemental Indenture, dated as of December 1, 2010.
4.51	(with Form 8-K dated as of December 30, 2010)	4.1	Fiftieth Supplemental Indenture, dated as of December 1, 2010.
4.52	(with Form 8-K dated as of February 11, 2011)	4.1	Fifty-First Supplemental Indenture, dated as of February 1, 2011.
4.53	(with Form 8-K dated as of August 16, 2011)	4.1	Fifty-Second Supplemental Indenture, dated as of August 1, 2011.
4.54	(with Form 8-K dated as of December 14, 2011)	4.1	Fifty-Third Supplemental Indenture, dated as of December 1, 2011.
4.55	(with Form 8-K dated as of November 30, 2012)	4.1	Fifty-Fourth Supplemental Indenture, dated as of November 1, 2012.
4.56	(with Form 8-K dated as of August 14, 2013)	4.1	Fifty-Fifth Supplemental Indenture, dated as of August 1, 2013.
4.57	(with Form 8-K dated as of April 18, 2014)	4.1	Fifty-Sixth Supplemental Indenture, dated as of April 1, 2014.
4.58	(with Form 8-K dated as of December 18, 2014)	4.1	Fifty-Seventh Supplemental Indenture, dated as of December 1, 2014.
4.59	(with Form 8-K dated as of December 16, 2015)	4.1	Fifty-Eighth Supplemental Indenture, dated as of December 1, 2015.
4.60	(with Form 8-K dated as of December 16, 2016)	4.1	Fifty-Ninth Supplemental Indenture, dated as of December 1, 2016.

Exhibit	Previously Filed[1] With Registration Number	As Exhibit	
4.61	(with Form 8-K dated as of December 14, 2017)	4.1	Sixtieth Supplemental Indenture, dated as of December 1, 2017.
4.62	(with Form 8-K dated as of May 15, 2018)	4(a)(62)	Sixty-First Supplemental Indenture, dated as of May 1, 2018.
4.63	(with Form 8-K dated as of November 26, 2019)	4.1	Sixty-Second Supplemental Indenture, dated as of November 1, 2019.
4.64	(with Form 8-K dated as of June 4, 2020)	4.1	Sixty-Third Supplemental Indenture, dated as of June 1, 2020.
4.65	(with Form 8-K dated as of September 30, 2020)	4.1	Sixty-Fourth Supplemental Indenture, dated as of September 1, 2020.
4.66	(with Form 8-K dated as of September 30, 2021)	4.1	Sixty-Fifth Supplemental Indenture, dated as of September 1, 2021.
4.67	333-82165	4(a)	Indenture dated as of April 1, 1998 between Avista Corporation and The Bank of New York, as Successor Trustee.
4.68	(with Form 8-K dated as of December 15, 2004)	4.5	Supplemental Indenture No. 1, dated as of December 1, 2004 to the Indenture dated as of April 1, 1998 between Avista Corporation and JPMorgan Chase Bank, N.A.
4.69	(with Form 8-K dated as of December 15, 2010)	4.1	Loan Agreement between City of Forsyth, Montana and Avista Corporation $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010A dated as of December 1, 2010.
4.70	(with Form 8-K dated as of December 15, 2010)	4.3	Trust Indenture between City of Forsyth, and the Bank of New York Mellon Trust Company, N.A., as Trustee, $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010A, dated as of December 1, 2010.
4.71	(with Form 8-K dated as of December 15, 2010)	4.2	Loan Agreement between City of Forsyth, Montana and Avista Corporation $17,000,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010B dated as of December 1, 2010.
4.72	(with Form 8-K dated as of December 15, 2010)	4.4	Trust Indenture between City of Forsyth, and the Bank of New York Mellon Trust Company, N.A., as Trustee, $17,000,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010B, dated as of December 1, 2010.
4.73	(with June 30, 2012 Form 10-Q)	3.1	Restated Articles of Incorporation of Avista Corporation, as amended and restated June 6, 2012 (see Exhibit 3.1 herein).
4.74	(with Form 8-K filed as of August 17, 2016)	3.2	Bylaws of Avista Corporation, as amended August 17, 2016 (see Exhibit 3.2 herein).
4.75	[2]		Description of the Registrant's Securities registered under Section 12 of the Securities Exchange Act of 1934.

Exhibit	Previously Filed [1] With Registration Number	As Exhibit	
10.1	(with Form 8-K dated as of February 11, 2011)	10.1	Credit Agreement, dated as of February 11, 2011, among Avista Corporation, the Banks Party hereto, The Bank of New York Mellon, Keybank National Association, and U.S. Bank National Association, as Co-Documentation Agents, Wells Fargo Bank National Association as Syndication Agent and an Issuing Bank, and Union Bank N.A. as Administrative Agent and an Issuing Bank.
10.2	(with Form 8-K dated as of April 18, 2014)	10.1	Second Amendment to Credit Agreement, dated as of April 18, 2014, among Avista Corporation, Wells Fargo Bank, National Association, as an Issuing Bank, Union Bank, N.A. as Administrative Agent and an Issuing Bank, and the financial institutions identified hereof as Continuing Lenders and Exiting Lender.
10.3	(with Form 8-K dated as of April 18, 2014)	10.2	Bond Delivery Agreement, dated as of April 18, 2014, between Avista Corporation and Union Bank, N.A.
10.4	(with Form 8-K dated as of December 14, 2011)	10.1	First Amendment and Waiver Thereunder, dated as of December 14, 2011, to the Credit Agreement dated as of February 11, 2011, among Avista Corporation, the Banks Party hereto, Wells Fargo Bank National Association as an Issuing Bank, and Union Bank N.A. as Administrative Agent and an Issuing Bank.
10.5	(with 2002 Form 10-K)	10(b)-3	Priest Rapids Project Product Sales Contract executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
10.6	(with 2002 Form 10-K)	10(b)-4	Priest Rapids Project Reasonable Portion Power Sales Contract executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
10.7	(with 2002 Form 10-K)	10(b)-5	Additional Product Sales Agreement (Priest Rapids Project) executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
10.8	2-60728	5(g)	Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of September 18, 1963.*
10.9	2-60728	5(g)-1	Amendment to Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of February 9, 1965.*
10.10	2-60728	5(h)	Reserved Share Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of September 18, 1963.*
10.11	2-60728	5(h)-1	Amendment to Reserved Share Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of February 9, 1965.*

Exhibit Index (continued)

Exhibit	With Registration Number	Previously Filed [1] As Exhibit	
10.12	(with September 30, 1985 Form 10-Q)	1	Settlement Agreement and Covenant Not to Sue executed by the United States Department of Energy acting by and through the Bonneville Power Administration and the Company, dated as of September 17, 1985, describing the settlement of Project 3 litigation.*
10.13	(with 1981 Form 10-K)	10(s)-7	Ownership and Operation Agreement for Colstrip Units No. 3 & 4, dated as of May 6, 1981.*
10.14	(with 2019 Form 10-K)	10.14	Avista Corporation Executive Deferral Plan (2020 Component). [3][5]
10.15	(with 2019 Form 10-K)	10.15	Avista Corporation Supplemental Executive Retirement Plan (Post-2004 Component, Amended in 2018). [3][6]
10.16	(with 1992 Form 10-K)	10(t)-11	The Company's Unfunded Supplemental Executive Disability Plan. [3]*
10.17	(with 2007 Form 10-K)	10.34	Income Continuation Plan of the Company. [3]
10.18	(with 2018 Form 10-K)	10.21	Avista Corporation Long-Term Incentive Plan. [3]
10.19	(with 2010 Form 10-K)	10.23	Avista Corporation Performance Award Plan Summary. [3]
10.20	(with 2019 Form 10-K)	10.22	Avista Corporation Performance Award Agreement 2019. [3]
10.21	(with 2020 Form 10-K)	10.22	Avista Corporation Performance Award Agreement 2020. [3]
10.22	[2]		Avista Corporation Performance Award Agreement 2021. [3]
10.23	[2]		Avista Corporation Officer Incentive Plan. [3]
10.24	(with Form 8-K dated August 13, 2008)	10.1	Employment Agreement between the Company and Mark T. Thies in the form of a Letter of Employment. [3]
10.25	(with September 30, 2019 Form 10-Q)	10.1	Form of Change of Control Plan between the Company and its Executive Officers. [3][7]
10.26	[2]		Avista Corporation Non-Employee Director Compensation.
10.27	(with Form 8-K dated April 6, 2020)	10.1	Credit Agreement, dated as of April 6, 2020, among Avista Corporation, U.S. Bank National Association, as Lender and Administrative Agent, and CoBank, ACB, as Lender.
21	[2]		Subsidiaries of Registrant.
23	[2]		Consent of Independent Registered Public Accounting Firm.
31.1	[2]		Certification of Chief Executive Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002).
31.2	[2]		Certification of Chief Financial Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002).
32	[4]		Certification of Corporate Officers (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002).

	Previously Filed [1]		
Exhibit	With Registration Number	As Exhibit	
101.INS	(2)		Inline XBRL Instance Document—the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH	(2)		Inline XBRL Taxonomy Extension Schema Document.
101.CAL	(2)		Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	(2)		Inline XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	(2)		Inline XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	(2)		Inline XBRL Taxonomy Extension Presentation Linkbase Document.
104	(2)		Cover page formatted as Inline XBRL and contained in Exhibit 101.

* *Exhibit originally filed with the U.S. Securities and Exchange Commission in paper format and as such, a hyperlink is not available.*

(1) *Incorporated herein by reference.*

(2) *Filed herewith.*

(3) *Management contracts or compensatory plans filed as exhibits to this Form 10-K pursuant to Item 15(b).*

(4) *Furnished herewith.*

(5) *Applies to Kevin J. Christie, Bryan A. Cox, Gregory C. Hesler, Latisha D. Hill, James M. Kensok, Ryan L. Krasselt, David J. Meyer, Heather L. Rosentrater, Edward D. Schlect, Jason R. Thackston, Mark T. Thies, and Dennis P. Vermillion.*

(6) *Applies to Kevin J. Christie, Bryan A. Cox, Latisha D. Hill, James M. Kensok, Ryan L. Krasselt, David J. Meyer, Heather L. Rosentrater, Jason R. Thackston, Mark T. Thies, and Dennis P. Vermillion.*

(7) *Applies to Kevin J. Christie, Bryan A. Cox, Gregory C. Hesler, Latisha D. Hill, James M. Kensok, Ryan L. Krasselt, David J. Meyer, Heather L. Rosentrater, Edward D. Schlect, Jason R. Thackston, Mark T. Thies, and Dennis P. Vermillion.*

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

AVISTA CORPORATION

February 22, 2022	By /s/ Dennis P. Vermillion
Date	Dennis P. Vermillion
	President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Dennis P. Vermillion Dennis P. Vermillion President and Chief Executive Officer	Principal Executive Officer and Director	February 22, 2022
/s/ Mark T. Thies Mark T. Thies Executive Vice President, Chief Financial Officer, and Treasurer	Principal Financial Officer	February 22, 2022
/s/ Ryan L. Krasselt Ryan L. Krasselt Vice President, Controller and Principal Accounting Officer	Principal Accounting Officer	February 22, 2022
/s/ Scott L. Morris Scott L. Morris Chairman of the Board	Director	February 22, 2022
/s/ Julie A. Bentz Julie A. Benz	Director	February 22, 2022
/s/ Kristianne Blake Kristianne Blake	Director	February 22, 2022
/s/ Donald C. Burke Donald C. Burke	Director	February 22, 2022
/s/ Rebecca A. Klein Rebecca A. Klein	Director	February 22, 2022
/s/ Sena M. Kwawu Sena M. Kwawu	Director	February 22, 2022
/s/ Scott H. Maw Scott H. Maw	Director	February 22, 2022
/s/ Jeffry L. Philipps Jeffry L. Philipps	Director	February 22, 2022
/s/ Heidi B. Stanley Heidi B. Stanley	Director	February 22, 2022
/s/ Janet D. Widmann Janet D. Widmann	Director	February 22, 2022

Exhibit 21

Avista Corporation

Subsidiaries of Registrant

Subsidiary	State or Country of Incorporation
Avista Capital, Inc.	Washington
Avista Development, Inc.	Washington
Avista Edge, Inc.	Washington
Avista Northwest Resources, LLC	Washington
Pentzer Corporation	Washington
Pentzer Venture Holding II, Inc.	Washington
Avista Capital II	Delaware
Courtyard Office Center, LLC	Washington
Alaska Energy and Resources Company	Alaska
Alaska Electric Light and Power Company	Alaska
AJT Mining Properties, Inc.	Alaska
Snettisham Electric Company	Alaska
Salix, Inc.	Washington
University Development Company, LLC	Washington

Exhibit 23

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in Registration Statement Nos. 333-33790, 333-179042 and 333-208986 on Form S-8 and in Registration Statement No. 333-231431 on Form S-3 of our reports dated February 22, 2022, relating to the financial statements of Avista Corporation, and the effectiveness of Avista Corporation's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Avista Corporation for the year ended December 31, 2021.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 22, 2022

Exhibit 31.1

Certification

I, Dennis P. Vermillion, certify that:

1. I have reviewed this report on Form 10-K of Avista Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 22, 2022

/s/ Dennis P. Vermillion
Dennis P. Vermillion
President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

Certification

I, Mark T. Thies, certify that:

1. I have reviewed this report on Form 10-K of Avista Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 22, 2022

/s/ Mark T. Thies
Mark T. Thies
Executive Vice President,
Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Exhibit 32

Avista Corporation

Certification of Corporate Officers

(Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)

Each of the undersigned, Dennis P. Vermillion, President and Chief Executive Officer of Avista Corporation (the "Company"), and Mark T. Thies, Executive Vice President and Chief Financial Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Company's Annual Report on Form 10-K for the year ended December 31, 2021 fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended, and that the information contained therein fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 22, 2022

/s/ Dennis P. Vermillion
Dennis P. Vermillion
President and Chief Executive Officer

/s/ Mark T. Thies
Mark T. Thies
Executive Vice President,
Chief Financial Officer, and Treasurer

Selected Financial Data

Avista Corporation

As of and for the years ended December 31,

Dollars in thousands, except per share data and ratios

	2021	2020	2019	2018	2017	2011
FINANCIAL RESULTS						
Operating revenues	$ 1,438,936	$ 1,321,891	$ 1,345,622	$ 1,396,893	$ 1,445,929	$ 1,481,932
Operating expenses	1,210,704	1,089,191	1,135,233	1,135,780	1,153,750	1,274,845
Income from continuing operations	228,232	232,700	210,389	261,113	292,179	207,087
Interest expense	106,152	105,061	104,354	100,936	96,192	73,903
Income taxes	12,031	7,051	31,374	26,060	82,758	48,780
Net income from continuing operations	147,334	129,488	196,763	136,598	115,932	90,658
Net income (loss) from discontinued operations	—	—	—	—	—	12,881
Net income	147,334	129,488	196,763	136,598	115,932	103,539
Net income attributable to noncontrolling interests	—	—	216	(169)	(16)	(3,315)
Net income attributable to Avista Corp. shareholders:						
Net income from continuing operations attributable to Avista Corp. shareholders	$ 147,334	$ 129,488	$ 196,979	$ 136,429	$ 115,916	$ 90,553
Net income from discontinued operations attributable to Avista Corp. shareholders	$ —	$ —	$ —	$ —	$ —	$ 9,671
Net income attributable to Avista Corp. shareholders	$ 147,334	$ 129,488	$ 196,979	$ 136,429	$ 115,916	$ 100,224
Earnings per common share attributable to Avista Corp shareholders—diluted:						
Earnings from continuing operations	2.10	1.90	2.97	2.07	1.79	$ 1.56
Earnings from discontinued operations	—	—	—	—	—	0.16
Total	2.10	1.90	2.97	2.07	1.79	1.72
Earnings per common share attributable to Avista Corp. shareholders—basic:	2.11	1.91	2.98	2.08	1.80	1.73
COMMON STOCK STATISTICS						
Dividends paid per common share	$ 1.69	$ 1.62	$ 1.55	$ 1.49	$ 1.43	$ 1.10
Book value per common share	$ 30.14	$ 29.31	$ 28.87	$ 26.99	$ 26.41	$ 20.30
Shares of common stock:						
Outstanding at year-end	71,498	69,239	67,177	65,688	65,494	58,423
Average—basic	69,951	67,962	66,205	65,673	64,496	57,872
Average—diluted	70,085	68,102	66,329	65,946	64,806	58,092
Return on average Avista Corp. stockholders' equity:						
Total company	7.1%	6.6%	10.5%	7.8%	6.9%	8.7%
Utility only	6.7%	7.1%	11.0%	8.5%	7.5%	8.4%
Non-utility only	10.0%	2.2%	6.6%	1.0%	0.7%	12.4%
Common stock price:						
High	$ 49.14	$ 53.00	$ 49.47	$ 52.91	$ 52.74	$ 26.53
Low	$ 36.68	$ 32.09	$ 39.75	$ 42.48	$ 37.94	$ 21.13
Year-end close	$ 42.49	$ 40.14	$ 48.09	$ 42.48	$ 51.49	$ 25.75

Selected Financial Data (continued)

Avista Corporation

As of and for the years ended December 31,

Dollars in thousands, except per share data and ratios

	2021	2020	2019	2018	2017	2011
DEBT AND PREFERRED STOCK STATISTICS						
Pretax interest coverage:						
Including AFUDC/AFUCE	2.54(x)	2.37(x)	3.30(x)	2.67(x)	3.11(x)	3.16(x)
Excluding AFUDC/AFUCE	2.43(x)	2.26(x)	3.19(x)	2.57(x)	3.00(x)	3.09(x)
Embedded cost of long-term debt	4.95%	5.06%	5.17%	5.33%	5.58%	5.76%
FINANCIAL CONDITION						
Total assets (1) (2)	$ 6,853,583	$ 6,402,097	$ 6,082,456	$ 5,782,576	$ 5,514,732	$ 3,909,305
Total net Avista Utilities property	5,078,326	4,842,995	4,649,884	4,450,078	4,196,691	2,860,776
Avista Utilities property capital expenditures (excluding equity-related AFUDC)	435,887	397,292	434,077	418,741	405,938	239,782
Long-term debt and leases (including current portion) (2)	2,267,554	2,132,249	2,020,011	1,863,174	1,769,237	1,165,014
Nonrecourse long-term debt of Spokane Energy (including current portion)	—	—	—	—	—	46,471
Long-term debt to affiliated trusts	51,547	51,547	51,547	51,547	51,547	51,547
Avista Corporation stockholders' equity	$ 2,154,744	$ 2,029,726	$ 1,939,284	$ 1,773,220	$ 1,729,828	$ 1,185,701

(1) The total assets at year-end for 2011 exclude the total assets associated with Ecova of $292.9 million.

(2) The total assets and total long-term debt for 2011 were adjusted in accordance with a change in accounting standards.

Selected Financial Data (continued)

Avista Corporation

As of and for the years ended December 31,

	2021	2020	2019	2018	2017	2011
AVISTA UTILITIES						
Electric Operations						
Electric operating revenues (millions of dollars):						
Residential	$ 394.7	$ 377.8	$ 369.1	$ 368.8	$ 381.7	$ 324.9
Commercial	326.2	304.0	317.6	314.5	311.6	280.1
Industrial	106.8	103.1	105.8	109.8	111.0	122.6
Public street and highway lighting	7.5	7.3	7.4	7.5	7.5	6.9
Total retail	835.1	792.2	799.9	800.6	811.8	734.5
Wholesale	89.8	77.3	73.2	85.0	81.5	78.3
Sales of fuel	63.7	28.8	48.0	62.2	64.9	153.5
Other	36.3	30.1	29.0	29.3	31.6	21.9
Decoupling	(19.5)	(4.4)	8.7	4.9	(8.2)	—
Provision for earning sharing	1.7	3.5	3.1	(11.5)	(1.2)	—
Total electric operating revenues	$ 1,007.1	$ 927.5	$ 962.0	$ 970.5	$ 980.4	$ 988.2
Electric energy sales (millions of kWhs):						
Residential	3,955	3,807	3,766	3,627	3,840	3,728
Commercial	3,158	2,995	3,170	3,156	3,222	3,122
Industrial	1,666	1,615	1,691	1,772	1,815	2,147
Public street and highway lighting	17	18	18	18	20	26
Total retail	8,796	8,435	8,645	8,573	8,897	9,023
Wholesale	2,461	2,680	2,787	3,632	2,881	2,796
Total electric energy sales	11,257	11,115	11,432	12,205	11,778	11,819
Retail electric customers (average per year):						
Residential	356,387	350,669	345,064	340,308	334,848	316,762
Commercial	44,110	43,497	42,930	42,618	42,154	39,618
Industrial	1,205	1,277	1,305	1,318	1,328	1,380
Public street and highway lighting	666	639	612	594	569	455
Total retail electric customers	402,368	396,082	389,911	384,838	378,899	358,215
Retail electric customers (at year-end):						
Residential	359,452	354,191	348,111	342,996	337,936	318,694
Commercial	44,303	43,968	42,790	42,621	42,280	39,826
Industrial	1,195	1,210	1,293	1,297	1,320	1,385
Public street and highway lighting	672	649	634	604	595	456
Total retail electric customers	405,622	400,018	392,828	387,518	382,131	360,361
Revenue per residential kWh (cents)	9.98	9.92	9.80	10.17	9.94	8.71
Use per residential customer (kWh)	11,098	10,857	10,914	10,658	11,469	11,769
Revenue per commercial kWh (cents)	10.33	10.15	10.02	9.97	9.67	8.97
Use per commercial customer (kWh)	71,589	68,847	73,842	74,059	76,444	78,804
Electric energy resources (millions of kWhs):						
Hydro generation (from Company facilities)	3,598	3,651	3,520	4,029	3,978	4,534
Thermal generation (from Company facilities)	3,635	3,474	4,054	3,424	3,476	2,447
Purchased power	4,954	4,922	4,833	5,349	4,809	5,435
Power exchanges	(398)	(446)	(504)	(109)	(6)	(24)
Total power resources	11,789	11,601	11,903	12,693	12,257	12,392
Energy losses and company use	(532)	(486)	(471)	(488)	(479)	(573)
Total electric energy resources	11,257	11,115	11,432	12,205	11,778	11,819

Selected Financial Data (continued)

Avista Corporation

As of and for the years ended December 31,

	2021	2020	2019	2018	2017	2011
AVISTA UTILITIES						
Electric Operations (continued)						
Retail Native Load at time of system peak						
Winter	1,696	1,613	1,577	1,555	1,681	1,669
Summer	1,889	1,721	1,656	1,716	1,596	1,535
Natural Gas Operations						
Natural gas operating revenues (millions of dollars):						
Residential	$ 221.4	$ 213.6	$ 196.4	$ 194.3	$ 220.2	$ 219.6
Commercial	100.8	94.9	92.2	89.4	104.2	111.9
Industrial and interruptible	7.8	7.2	5.3	4.8	5.7	6.7
Total retail	330.0	315.7	293.9	288.5	330.1	338.2
Wholesale	113.3	104.9	135.0	137.1	142.7	195.9
Transportation	8.5	7.9	8.7	9.1	9.2	6.7
Other	7.3	5.0	7.4	6.8	6.4	7.4
Decoupling	12.9	0.6	0.9	(4.0)	(11.4)	—
Provision for earning sharing	1.3	1.8	1.4	(6.8)	(2.4)	—
Total natural gas operating revenues	$ 473.3	$ 435.9	$ 447.2	$ 430.7	$ 474.6	$ 548.2
Natural gas therms delivered (millions of therms):						
Residential	219.8	220.0	231.2	208.3	222.0	207.2
Commercial	130.4	127.6	140.6	124.7	133.3	125.3
Industrial and interruptible	21.4	20.3	15.4	11.6	11.8	10.2
Total retail	371.6	367.9	387.2	344.6	367.1	342.7
Wholesale	356.9	542.4	590.8	503.9	545.3	510.8
Transportation and other	172.8	180.7	187.9	176.8	186.7	152.9
Total natural gas therms delivered	901.3	1,091.0	1,165.9	1,025.3	1,099.1	1,006.4
Retail natural gas customers (average per year):						
Residential	332,187	327,125	321,343	314,800	307,375	284,504
Commercial	36,448	36,164	35,804	35,488	35,192	33,540
Industrial and interruptible	232	265	286	285	288	293
Total retail natural gas customers	368,867	363,554	357,433	350,573	342,855	318,337
Retail natural gas customers (at year-end):						
Residential	335,166	330,124	325,102	318,847	311,518	286,567
Commercial	36,622	36,483	36,101	35,668	35,353	33,730
Industrial and interruptible	237	229	292	284	289	295
Total retail natural gas customers	372,025	366,836	361,495	354,799	347,160	320,592
Revenue per residential therm (in dollars)	1.01	0.97	0.85	0.93	0.99	1.06
Use per residential customer (therms)	662	672	720	662	722	728
Revenue per commercial therm (in dollars)	0.77	0.74	0.66	0.72	0.78	0.89
Use per commercial customer (therms)	3,578	3,530	3,926	3,513	3,789	3,737
Heating degree days (at Spokane, Washington):						
Actual	6,124	6,187	6,817	6,159	6,783	6,861
30 year average	6,596	6,651	6,613	6,593	6,578	6,647
Actual as a percent of average	93%	93%	103%	93%	103%	103%

Avista Corporation

As of and for the years ended December 31,

	2021	2020	2019	2018	2017	2011
ALASKA ELECTRIC LIGHT AND POWER COMPANY						
Revenues (millions of dollars)	$ 45.4	$ 42.8	$ 37.3	$ 43.6	$ 53.0	$ —
Total assets (millions of dollars)	$ 265.4	$ 269.0	$ 271.4	$ 273.0	$ 278.7	$ —
ECOVA						
Revenues (millions of dollars)	$ —	$ —	$ —	$ —	$ —	$ 137.8
Total assets (millions of dollars)	$ —	$ —	$ —	$ —	$ —	$ 292.9
OTHER						
Revenues (millions of dollars)	$ 0.6	$ 1.6	$ 12.5	$ 27.3	$ 22.5	$ 40.4
Total assets (millions of dollars)	$ 132.2	$ 109.7	$ 113.4	$ 87.1	$ 73.2	$ 112.1

Corporate Information

Company Headquarters
Spokane, Washington

Avista on the Internet
Financial results, stock quotes, news releases, documents filed with the Securities and Exchange Commission (SEC), and information on the company's products and services are available on Avista's website at **investor.avistacorp.com**.

Direct Stock Purchase and Dividend Reinvestment Plan
Computershare sponsors and administers the Computershare Investment Plan (CIP) for Avista Corp. common stock. To invest, obtain forms, or for information about your holdings, please contact the transfer agent using the information below.

Transfer Agent
Computershare
P.O. Box 505000
Louisville, KY 40233
800.642.7365
computershare.com/investor

Investor Information
A copy of the company's financial reports, including the reports on Forms 10-K and 10-Q filed with the SEC, will be provided without charge upon request to:
Avista Corp.
Investor Relations
P.O. Box 3727 MSC-19
Spokane, WA 99220-3727
800.222.4931

Annual Meeting of Shareholders
The company's annual meeting will be held at 8:15 a.m. PDT on Thursday, May 12, 2022.

Due to the impact of the COVID-19 pandemic, and to support the health and well-being of our employees and shareholders, please note that this year's meeting will be held in a virtual format only.

Exchange Listing
Ticker Symbol: AVA
New York Stock Exchange

Certifications
On May 13, 2021, the Chief Executive Officer (CEO) of Avista Corp. filed a Section 303A.12(a) Annual CEO Certification with the New York Stock Exchange. The CEO Certification attests that the CEO is not aware of any violations by the company of NYSE's Corporate Governance Listing Standards.

Avista Corp. has included as exhibits to its annual report on Form 10-K for the year 2021, filed with the SEC, certifications of Avista's Chief Executive Officer and Chief Financial Officer regarding the quality of Avista's public disclosure in compliance with Section 302 of the Sarbanes-Oxley Act of 2002.

This annual report contains forward-looking statements regarding the company's current expectations. These statements are subject to a variety of risks and uncertainties that could cause actual results to differ materially from the expectations. These risks and uncertainties include, in addition to those discussed herein, all factors discussed in the company's annual report on Form 10-K for the year 2021. Our 2021 annual report is provided for shareholders. It is not intended for use in connection with any sale or purchase of or any solicitation of others to buy or sell securities.

The 2021 annual report is produced through a partnership of Avista employees and companies within Avista's service area. Design and Production: Klündt | Hosmer; Photography: Dean Davis Photography; Printing: Lawton Printing Services

Help Us Help the Environment
Managing costs is a primary goal for Avista. You can help us meet this goal by agreeing to receive future annual reports and proxy statements electronically. This service saves on the costs of printing and mailing, provides timely delivery of information, and helps protect our environment by decreasing the need for paper, printing, and mailing materials.

For more information, please visit:
investor.avistacorp.com

In our commitment to green thinking, this year's annual report is printed on paper made from responsibly managed forests.

1411 East Mission Avenue, Spokane, Washington 99202 | 509.489.0500 | avistacorp.com

Basis of presentation on filed forms:						
Balance Sheet - Total Gas & Electric						
Plant in Service Details - Gas Only						
Statement of Retained Earnings - Total Gas & Electric	-	-	-	-	(0.00)	(0.00)
Income Statement Details - Gas Only	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
	Debit (Credit)	**Debit (Credit)**	**Debit (Credit)**	**Debit (Credit)**	**Debit (Credit)**	**Debit (Credit)**
100-199 Assets and Other Debits.						
Electric Utility and Common Plant	4,252,915,263	4,516,368,326	4,757,419,803	5,041,795,377	5,289,223,861	5,566,484,358
1. Utility Plant						
101 Gas plant in service.						
101.1 Property under capital leases.						
102 Gas plant purchased or sold.						
103 Experimental gas plant unclassified.						
104 Gas plant leased to others.						
105 Gas plant held for future use.	9,941,983	8,321,112	9,036,047	12,951,318	13,727,648	18,875,451
105.1 Production properties held for future use.						
106 Completed construction not classified - Gas.						
107 Construction work in progress - Gas.	144,751,274	151,271,170	156,563,570	157,909,990	172,073,892	196,305,682
108 Accumulated provision for depreciation of gas utility plant.	(1,701,243,278)	(1,796,469,363)	(1,895,743,265)	(1,995,071,691)	(2,132,757,425)	(2,274,836,782)
109 [Reserved]						
111 Accumulated provision for amortization and depletion of gas utility plant.	(69,268,142)	(79,794,309)	(95,497,118)	(126,822,214)	(161,605,178)	(190,221,535)
111.1-111.2 [Reserved]						
112 [Reserved]						
113.1-113.2 [Reserved]						
114 Gas plant acquisition adjustments.						
115 Accumulated provision for amortization of gas plant acquisition adjustments.						
116 Other gas plant adjustments.						
117.1 Gas stored-Base gas.	6,992,076	6,992,076	6,992,076	6,992,076	6,992,076	6,992,076
117.2 System balancing gas.						
117.3 Gas stored in reservoirs and pipelines-noncurrent.						
117.4 Gas owed to system gas.						
118 Other utility plant.						
119 Accumulated provision for depreciation and amortization of other utility plant.						
2. Other Property and Investments						
121 Nonutility property.	3,058,415	3,010,811	4,474,923	4,340,611	5,311,287	4,500,764
122 Accumulated provision for depreciation and amortization of nonutility property.	(211,651)	(104,487)	(140,360)	(176,234)	(212,107)	(247,981)
123 Investment in associated companies.	11,547,000	11,547,000	11,547,000	11,547,000	11,547,000	11,547,000
123.1 Investment in subsidiary companies.	161,804,156	161,131,682	153,523,686	207,105,954	207,410,331	225,965,712
124 Other investments.	6,945,185	4,288,775	1,711,072	77,972	77,890	77,890
125 Sinking funds.						
126 Depreciation fund.						
128 Other special funds.	13,611,799	16,722,286	18,794,801	22,034,002	24,673,077	11,152,367
3. Current and Accrued Assets						
131 Cash.	1,373,667	2,912,504	4,737,049	3,067,240	7,363,358	11,893,219
132 Interest special deposits.						
133 Dividend special deposits.						
134 Other special deposits.	7,540,762	12,284,827	26,809,063	4,434,090	4,335,989	21,477,352
135 Working funds.	1,138,883	1,149,696	709,204	730,965	1,116,351	1,227,292
136 Temporary cash investments.	22,854	50,305	136,712	155,890	152,774	153,241
141 Notes receivable.						
142 Customer accounts receivable.	172,903,052	174,683,071	157,729,381	153,814,551	161,513,344	183,224,129
143 Other accounts receivable.	4,163,026	5,614,311	4,618,679	15,726,829	56,664,630	50,330,014
144 Accumulated provision for uncollectible accounts - Cr.	(4,961,486)	(5,170,026)	(5,188,090)	(2,094,096)	(11,336,140)	(10,368,511)
145 Notes receivable from associated companies.	-	11,659,191	31,659,207	-	-	
146 Accounts receivable from associated companies.	462,036	313,553	154,548	222,671	719,507	738,517
151 Fuel stock.	3,566,367	3,958,296	3,982,104	4,148,891	4,088,628	4,388,454
152 Fuel stock expenses undistributed.						
153 Residuals and extracted products.						
154 Plant materials and operating supplies (Major only).	37,423,657	38,180,423	43,166,166	46,558,819	51,854,056	60,277,408
155 Merchandise.						
156 Other materials and supplies.						
163 Stores expense undistributed.	(86)					
164.1 Gas stored - current.	8,029,020	11,738,607	11,609,184	14,305,397	9,535,324	17,603,996
164.2 Liquefied natural gas stored.						
164.3 Liquefied natural gas held for processing.						
165 Prepayments.	14,459,235	19,333,312	20,211,526	24,682,259	26,280,659	22,973,644
166 Advances for gas exploration, development, and production.						
167 Other advances for gas.						
171 Interest and dividends receivable.	107,608	172,493	166,418	129,823	24,973	20,633
172 Rents receivable.	1,429,562	2,101,931	2,516,807	3,609,148	2,934,797	3,665,325
173 Accrued utility revenues.						
174 Miscellaneous current and accrued assets.	537,127	138,513	398,132	193,803	236,392	113,893
175 Derivative Instrument Assets	10,644,436	6,197,881	10,394,941	1,780,327	1,523,219	4,056,941
4. Deferred Debits						
181 Unamortized debt expense.	11,690,512	10,945,098	13,923,600	13,795,818	15,341,337	16,420,883
182.1 Extraordinary property losses.						
182.2 Unrecovered plant and regulatory study costs.						
182.3 Other regulatory assets.	622,464,411	621,273,693	598,724,109	643,207,368	717,281,643	833,162,908
183.0 Preliminary Survey and Investigation Charges (Electric)	-	195,568	2,313	-		
183.1 Preliminary natural gas survey and investigation charges.	-	299				
183.2 Other preliminary survey and investigation charges.						
184 Clearing accounts.	13,933	69,497	28,530	131,978	152,201	122,784
185 Temporary facilities.						
186 Miscellaneous deferred debits.	43,850,403	15,796,170	30,900,539	18,484,368	29,826,563	50,762,924
187 Deferred losses from disposition of utility plant.						
188 Research, development, and demonstration expenditures.						
189 Unamortized loss on reacquired debt.	13,699,992	11,879,551	10,255,271	8,883,822	7,512,371	6,768,288
190 Accumulated deferred income taxes.	147,354,707	189,216,780	187,450,520	177,056,526	216,728,536	256,362,574
191 Unrecovered purchased gas costs.	(30,819,635)	(37,474,157)	(40,713,156)	(3,189,401)	1,433,580	21,025,867
200-299 Liabilities and Other Credits.						
5. Proprietary Capital						
201 Common stock issued.	(1,052,578,756)	(1,109,643,921)	(1,110,871,767)	(1,176,498,977)	(1,249,688,206)	(1,341,011,707)
202 Common stock subscribed.						
203 Common stock liability for conversion.						
204 Preferred stock issued.						
205 Preferred stock subscribed.						
206 Preferred stock liability for conversion.						
207 Premium on capital stock.						
208 Donations received from stockholders.						
209 Reduction in par or stated value of capital stock.						
210 Gain on resale or cancellation of reacquired capital stock.						
211 Miscellaneous paid-in capital.	9,506,476	10,696,711	10,696,711	10,696,711	10,696,711	10,696,711
212 Installments received on capital stock.						
213 Discount on capital stock.						
214 Capital stock expense.	(32,208,771)	(34,500,271)	(36,316,031)	(44,938,398)	(47,076,877)	(49,837,072)
215 Appropriated retained earnings.	(23,869,500)	(32,132,125)	(37,452,971)	(41,178,525)	(45,452,947)	(51,518,316)
216 Unappropriated retained earnings.	(517,393,547)	(558,287,446)	(574,023,727)	(623,531,170)	(705,980,176)	(726,160,557)
216.1 Unappropriated undistributed subsidiary earnings.	5,881,619	1,143,222	(56,139)	16,389,107	13,386,701	13,577,380
217 Reacquired capital stock.						
219 Accumulated Other Comprehensive Income	7,567,509	8,089,542	7,866,070	10,258,024	14,378,164	11,038,551
6. Long-Term Debt						
221 Bonds.	(1,621,700,000)	(1,711,700,000)	(1,814,200,000)	(1,904,200,000)	(2,017,200,000)	(2,157,200,000)
222 Reacquired bonds.	83,700,000	83,700,000	83,700,000	83,700,000	83,700,000	83,700,000
223 Advances from associated companies.	(51,547,000)	(51,547,000)	(51,547,000)	(51,547,000)	(51,547,000)	(51,547,000)
224 Other long-term debt.						
225 Unamortized premium on long-term debt.	(168,783)	(159,900)	(151,017)	(142,133)	(133,250)	(124,367)
226 Unamortized discount on long-term debt - Debit.	960,522	786,481	1,032,761	930,270	843,651	757,032
7. Other Noncurrent Liabilities.						

227 Obligations under capital leases - noncurrent.	(2,402,917)			(65,565,105)	(67,716,314)	(66,068,171)
228.1 Accumulated provision for property insurance.						
228.2 Accumulated provision for injuries and damages.	(260,000)	(245,000)	(245,000)	(245,000)	(395,000)	(731,009)
228.3 Accumulated provision for pensions and benefits.	(226,551,767)	(203,565,903)	(222,536,776)	(212,005,607)	(211,880,117)	(153,467,368)
228.4 Accumulated miscellaneous operating provisions.						
229 Accumulated provision for rate refunds.	(6,600,086)	(4,906,781)	(10,178,645)	(11,767,158)	(3,820,594)	(409,971)
230 Asset Retirement Obligations	(15,514,534)	(17,481,829)	(18,265,985)	(20,338,053)	(17,194,050)	(17,141,793)
8. Current and Accrued Liabilities						
231 Notes payable.	(120,000,000)	(105,000,000)	(190,000,000)	(182,300,000)	(202,000,000)	(284,000,000)
232 Accounts payable.	(111,124,132)	(100,959,825)	(103,484,597)	(107,406,813)	(104,217,591)	(127,662,677)
233 Notes payable to associated companies.	(5,634,684)			(14,722,348)	(8,742,915)	(1,404,713)
234 Accounts payable to associated companies.	(37,625)	(22,197)	(7,329)	-		(18,595)
235 Customer deposits.	(3,808,551)	(4,431,306)	(4,783,254)	(4,745,573)	(3,028,142)	(3,702,706)
236 Taxes accrued.	16,431,293	(36,514,038)	(39,835,469)	(38,022,918)	(45,266,874)	(41,669,378)
237 Interest accrued.	(14,676,249)	(15,159,301)	(15,509,062)	(15,282,041)	(15,884,942)	(16,347,042)
238 Dividends declared.						
239 Matured long-term debt.						
240 Matured interest.						
241 Tax collections payable.	(1,431,933)	(1,533,187)	(79,542)	(168,034)	(111,813)	(137,825)
242 Miscellaneous current and accrued liabilities.	(58,068,093)	(59,386,964)	(56,358,807)	(50,808,479)	(60,781,094)	(69,109,875)
243 Obligations under capital leases - current.	(871,667)	(2,402,917)		(4,127,651)	(4,249,213)	(4,300,958)
244 Derivative Instrument Liabilities	(55,076,777)	(53,752,463)	(14,252,910)	(30,612,670)	(51,435,582)	(33,326,256)
9. Deferred Credits						
252 Customer advances for construction.	(2,266,861)	(1,584,319)	(2,142,205)	(2,083,490)	(2,444,382)	(3,624,489)
253 Other deferred credits.	(15,262,118)	(28,032,143)	(22,466,066)	(29,659,558)	(31,450,029)	(30,183,652)
254 Other regulatory liabilities.	(77,740,268)	(501,143,487)	(527,440,814)	(481,207,133)	(473,121,377)	(571,662,225)
255 Accumulated deferred investment tax credits.	(31,501,931)	(30,265,611)	(29,725,443)	(30,443,961)	(29,866,627)	(29,313,176)
256 Deferred gains from disposition of utility plant.						
257 Unamortized gain on reacquired debt.	(1,836,970)	(1,707,433)	(1,577,896)	(1,448,359)	(1,318,822)	(1,189,285)
281 Accumulated deferred income taxes - Accelerated amortization property.						
282 Accumulated deferred income taxes - Other property.	(731,162,121)	(481,835,128)	(497,875,564)	(514,870,007)	(603,415,433)	(618,900,933)
283 Accumulated deferred income taxes - Other.	(246,457,751)	(167,572,569)	(170,209,151)	(179,585,209)	(200,118,168)	(266,782,124)
300-399 Plant Accounts.						
1. Intangible Plant						
301 Organization.						
302 Franchises and consents.						
303 Miscellaneous intangible plant.	3,471,887	2,880,555	2,916,864	2,764,767	2,585,617	2,664,583
2. Production Plant						
a. manufactured gas production plant						
304 Land and land rights.						
305 Structures and improvements.						
306 Boiler plant equipment.						
307 Other power equipment.						
308 Coke ovens.						
309 Producer gas equipment.						
310 Water gas generating equipment.						
311 Liquefied petroleum gas equipment.						
312 Oil gas generating equipment.						
313 Generating equipment - Other processes.						
314 Coal, coke, and ash handling equipment.						
315 Catalytic cracking equipment.						
316 Other reforming equipment.						
317 Purification equipment.						
318 Residual refining equipment.						
319 Gas mixing equipment.						
320 Other equipment.						
Manufactured Gas Production Plant	7,628	7,628	7,628	7,628	59,924	59,924
b. natural gas production plant						
B.1. Natural Gas Production and Gathering Plant						
325.1 Producing lands.						
325.2 Producing leaseholds.						
325.3 Gas rights.						
325.4 Rights-of-way.						
325.5 Other land and land rights.						
326 Gas well structures.						
327 Field compressor station structures.						
328 Field measuring and regulating station structures.						
329 Other structures.						
330 Producing gas wells - Well construction.						
331 Producing gas wells - Well equipment.						
332 Field lines.						
333 Field compressor station equipment.						
334 Field measuring and regulating station equipment.						
335 Drilling and cleaning equipment.						
336 Purification equipment.						
337 Other equipment.						
338 Unsuccessful exploration and development costs.						
B.2. Products Extraction Plant						
340 Land and land rights.						
341 Structures and improvements.						
342 Extraction and refining equipment.						
343 Pipe lines.						
344 Extracted product storage equipment.						
345 Compressor equipment.						
346 Gas measuring and regulating equipment.						
347 Other equipment.						
3. Natural Gas Storage and Processing Plant						
a. underground storage plant						
350.1 Land.	1,213,752	1,306,601	1,306,601	1,313,516	1,313,516	1,313,516
350.2 Rights-of-way.	59,812	59,812	59,812	66,742	66,742	66,742
351 Structures and improvements.	2,101,351	2,407,983	2,878,228	1,626,548	2,098,287	2,568,116
352 Wells.	13,930,342	14,166,928	14,891,527	18,002,576	18,474,314	18,922,731
352.1 Storage leaseholds and rights.	254,354	254,354				
352.2 Reservoirs.	1,667,492	1,667,492	1,667,492	1,667,492	1,667,492	1,667,492
352.3 Nonrecoverable natural gas.	5,810,311	5,810,311	5,810,311	5,810,311	5,810,311	5,810,311
353 Lines.	1,106,781	1,106,781	1,106,781	2,230,522	2,230,522	2,229,534
354 Compressor station equipment.	15,071,598	15,378,230	15,848,475	17,244,517	17,716,256	18,186,086
355 Measuring and regulating equipment.	878,291	1,184,923	1,655,168	769,085	1,240,824	1,710,400
356 Purification equipment.	403,712	403,712	403,712	560,248	560,248	560,248
357 Other equipment.	2,178,970	2,485,602	2,936,843	1,760,289	2,232,027	2,701,856
b. other storage plant						
360 Land and land rights.						
361 Structures and improvements.						
362 Gas holders.						
363 Purification equipment.						
363.1 Liquefaction equipment.						
363.2 Vaporizing equipment.						
363.3 Compressor equipment.						
363.4 Measuring and regulating equipment.						
363.5 Other equipment.						
c. base load liquefied natural gas terminaling and processing plant						
364.1 Land and land rights .						
364.2 Structures and improvements.						
364.3 LNG processing terminal equipment.						
364.4 LNG transportation equipment.						
364.5 Measuring and regulating equipment.						
364.6 Compressor station equipment.						
364.7 Communication equipment.						

364.8 Other equipment.						
4. Transmission Plant						
365.1 Land and land rights.						
365.2 Rights-of-way.						
366 Structures and improvements.						
367 Mains.						
368 Compressor station equipment.						
369 Measuring and regulating station equipment.						
370 Communication equipment.						
371 Other equipment.						
5. Distribution Plant						
374 Land and land rights.	886,774	920,102	1,179,375	1,521,412	1,532,328	1,584,263
375 Structures and improvements.	1,310,799	1,354,564	1,803,020	1,974,279	2,151,098	2,236,483
376 Mains.	504,017,728	547,688,874	597,220,229	633,397,298	671,777,189	705,689,470
377 Compressor station equipment.						
378 Measuring and regulating station equipment - General.	11,116,597	12,181,034	11,967,781	12,268,149	12,448,254	13,146,637
379 Measuring and regulating station equipment - City gate check stations.	8,906,586	9,087,273	8,721,669	9,235,056	9,365,034	9,853,403
380 Services.	305,467,723	332,999,643	369,619,102	397,234,010	421,652,768	451,435,611
381 Meters.	117,484,380	123,444,538	128,537,042	145,607,514	159,124,709	167,072,484
382 Meter installations.						
383 House regulators.						
384 House regulatory installations.						
385 Industrial measuring and regulating station equipment.	4,911,365	4,997,477	5,789,070	6,154,052	6,391,429	6,511,414
386 Other property on customers' premises.						
387 Other equipment.	539	539	539	539	539	601
6. General Plant						
389 Land and land rights.	1,449,716	3,367,309	3,607,121	3,921,827	3,921,927	3,918,902
390 Structures and improvements.	5,837,839	7,160,856	23,042,842	29,741,833	29,895,088	29,454,978
391 Office furniture and equipment.	621,582	736,399	1,186,531	1,267,984	464,773	474,505
392 Transportation equipment.	16,356,516	16,989,163	17,710,955	18,032,901	19,237,738	20,542,768
393 Stores equipment.	145,386	136,789	112,801	112,801	85,263	243,144
394 Tools, shop and garage equipment.	6,899,179	7,673,669	8,170,189	8,775,280	9,292,808	10,037,265
395 Laboratory equipment.	342,466	340,946	324,175	412,859	396,983	452,276
396 Power operated equipment.	4,080,550	3,996,441	4,096,408	4,199,994	4,367,784	4,273,025
397 Communication equipment.	3,405,773	3,545,025	3,714,172	2,723,028	2,611,409	1,917,901
398 Miscellaneous equipment.	2,367	2,367	2,367	2,367	2,367	9,092
399 Other tangible property.						
400-432, 434-435 Income Accounts.						
Electric Utility Net Operating Income	(167,967,764)	(175,229,610)	(180,295,919)	(181,882,120)	(184,584,253)	(170,387,951)
1. Utility Operating Income						
operating expenses						
400 Operating revenues.						
401 Operation expense.						
402 Maintenance expense.						
403 Depreciation expense.	28,452,086	30,576,899	33,889,018	36,824,230	39,241,553	40,926,795
404.1 Amortization and depletion of producing natural gas land and land rights.			-			
404.2 Amortization of underground storage land and land rights.						
404.3 Amortization of other limited-term gas plant.						
405 Amortization of other gas plant.	6,447,838	7,521,879	8,582,105	10,079,068	11,806,796	13,781,807
406 Amortization of gas plant acquisition adjustments.			-			
407.1 Amortization of property losses, unrecovered plant and regulatory study costs.						
407.2 Amortization of conversion expense.						
407.3 Regulatory debits.	(31,501)	209,310	849,367	1,453,061	4,291,442	5,808,607
407.4 Regulatory credits.	(8,432)	(371,562)	(1,566,161)	(3,442,644)	(9,347,623)	(6,127,306)
408 [Reserved]						
408.1 Taxes other than income taxes, utility operating income.	22,045,931	25,603,673	25,145,281	24,983,566	28,331,560	29,510,738
409 [Reserved]						
409.1 Income taxes, utility operating income.	(3,288,814)	10,818,985	2,854,673	(6,436,311)	(18,406,667)	2,801,361
410 [Reserved]						
410.1 Provision for deferred income taxes, utility operating income.	23,211,537	15,344,839	4,191,080	11,059,318	51,367,113	62,186,928
411 [Reserved]						
411.1 Provision for deferred income taxes - Credit, utility operating income.	(225,654)	(212,570)	116,242	(1,346,919)	(20,182,500)	(61,221,748)
411.3 [Reserved]						
411.4 Investment tax credit adjustments, utility operations.	(25,164)	(20,064)	(20,064)	172,256	(14,643)	(5,006)
411.6 Gains from disposition of utility plant.						
411.7 Losses from disposition of utility plant. Total utility operating expenses.						
411.10 Accretion Expense			-			
other operating income						
412 Revenues from gas plant leased to others.						
413 Expenses of gas plant leased to others.						
414 Other utility operating income. Net utility operating income.						
2. Other Income and Deductions						
a. other income						
415 Revenues from merchandising, jobbing and contract work.						
416 Costs and expenses of merchandising, jobbing and contract work.						
417 Revenues from nonutility operations.					(108,256)	(299,756)
417.1 Expenses of nonutility operations.	11,653,482	9,648,685	6,931,684	14,612,589	5,439,625	5,295,279
418 Nonoperating rental income.	939	24,801	31,262	31,291	31,838	31,838
418.1 Equity in earnings of subsidiary companies.	(6,288,876)	(2,517,761)	(2,392,004)	(13,582,269)	(5,304,376)	(23,555,382)
419 Interest and dividend income.	(2,719,466)	(4,001,578)	(3,808,319)	(4,401,266)	(3,448,647)	(3,650,892)
419.1 Allowance for other funds used during construction.	(7,298,983)	(6,441,370)	(4,281,829)	104,311	(338,811)	(589,900)
421 Miscellaneous nonoperating income.						
421.1 Gain on disposition of property. Total other income.	(240,297)	(19,733)		(109,159)	(289,281)	(109,527)
b. other income deductions						
421.2 Loss on disposition of property.	-	(17,500)	13,251	-		
425 Miscellaneous amortization.				(33,721)	(815,484)	5,616
426 [Reserved]						
426.1 Donations.	2,837,164	3,205,496	3,563,420	11,332,979	2,999,603	2,499,499
426.2 Life insurance.	2,589,158	2,967,371	2,793,863	2,640,044	3,072,596	3,591,498
426.3 Penalties.	(64,095)	18,562	2,053	21,180	(17,039)	22,039
426.4 Expenditures for certain civic, political and related activities.	1,788,417	1,663,123	2,073,702	1,718,553	1,773,265	1,935,266
426.5 Other deductions. Total other income deductions. Total other income and deductions.	1,915,238	17,741,930	5,342,674	27,317,212	3,494,856	4,448,958
c. taxes applicable to other income and deductions						
408.2 Taxes other than income taxes, other income and deductions.	192,113	175,689	293,278	311,708	923,792	564,779
409.2 Income taxes, other income and deductions.	(10,876,841)	(13,275,123)	(5,306,393)	(12,760,968)	(59,670)	(2,100,562)
410.2 Provision for deferred income taxes, other income and deductions.	1,585,996	7,571,606	34,584	(1,887,439)	218,831	3,042,777
411.2 Provision for deferred income taxes - Credit, other income and deductions.	(322,781)	(440,920)	(231,946)	(196,940)	(3,167,528)	(2,944,321)
411.5 Investment tax credit adjustments, nonutility operations.						
420 Investment tax credits. Total taxes on other income and deductions. Net other income and deductions.						
3. Interest Charges						
427 Interest on long-term debt.	74,527,233	82,342,603	87,093,842	86,591,406	88,943,779	91,728,400
428 Amortization of debt discount and expense.	458,080	321,206	321,207	321,206	937,453	941,948
428.1 Amortization of loss on reacquired debt.	2,941,399	2,854,749	2,582,801	2,266,507	2,222,423	1,592,056
429 Amortization of premium on debt - Credit.	(8,883)	(8,883)	(8,883)	(8,883)	(8,883)	(8,883)
429.1 Amortization of gain on reacquired debt - Credit.					-	
430 Interest on debt to associated companies.	766,389	677,027		489,554	186,289	515,447
431 Other interest expense.	4,386,030	5,657,334	6,749,117	8,205,984	6,170,081	4,860,055
432 Allowance for borrowed funds used during construction - Credit. Net interest charges.	(2,352,527)	(3,254,457)	(4,052,495)	(4,169,531)	(2,152,002)	(2,367,356)
4. Extraordinary Items						
434 Extraordinary income.				(102,999,990)		
435 Extraordinary deductions.						
409.3 Income taxes, extraordinary items. Net income				26,631,283		
433, 436-439 Retained Earnings Accounts.						
Retained Earnings Chart of Accounts						
433 Balance transferred from income.						
436 Appropriations of retained earnings.	4,441,571	8,262,625	5,320,848	3,725,552	4,274,422	6,065,368
437 Dividends declared - preferred stock.						
438 Dividends declared - common stock.	87,154,240	92,460,231	98,046,075	102,772,642	110,253,196	119,739,230

439 Adjustments to retained earnings.						
480-499 Revenue Accounts.						
1. Sales of Gas						
480 Residential sales.	(195,275,153)	(220,175,977)	(194,340,048)	(196,429,738)	(213,611,519)	(221,404,777)
481 Commercial and industrial sales.	(98,504,799)	(109,897,458)	(94,094,869)	(97,431,048)	(102,065,963)	(108,615,420)
482 Other sales to public authorities.						
483 Sales for resale.	(154,435,624)	(143,278,875)	(137,700,616)	(136,305,522)	(105,073,763)	(114,711,489)
484 Interdepartmental sales.	(288,085)	(315,487)	(271,572)	(253,068)	(252,564)	(328,145)
485 Intracompany transfers.						
2. Other Operating Revenues						
487 Forfeited discounts.						
488 Miscellaneous service revenues.	(139,015)	(140,525)	(116,985)	(106,672)	(43,452)	(27,568)
489.1 Revenues from transportation of gas of others through gathering facilities.						
489.2 Revenues from transportation of gas of others through transmission facilities.						
489.3 Revenues from transportation of gas of others through distribution facilities.	(8,338,713)	(9,207,927)	(9,102,582)	(8,673,782)	(7,916,862)	(8,547,319)
489.4 Revenues from storing gas of others.						
490 Sales of products extracted from natural gas.						
491 Revenues from natural gas processed by others.						
492 Incidental gasoline and oil sales.						
493 Rent from gas property.	(3,293)	(2,693)	(2,678)	(2,751)	(465)	(14,000)
494 Interdepartmental rents.						
495 Other gas revenues.	(17,100,272)	6,436,726	(1,022,412)	(7,228,294)	(4,986,835)	(18,827,764)
496 Provision for rate refunds	2,767,455	2,392,142	6,764,411	1,815,553	(3,192,858)	(1,093,458)
700-899 Production, Transmission and Distribution Expenses.						
1. Production Expenses						
a. manufactured gas production						
A.1. Steam Production						
Operation						
700 Operation supervision and engineering.						
701 Operation labor.						
702 Boiler fuel.						
703 Miscellaneous steam expenses.						
704 Steam transferred - Credit.						
Maintenance						
705 Maintenance supervision and engineering.						
706 Maintenance of structures and improvements.						
707 Maintenance of boiler plant equipment.						
708 Maintenance of other steam production plant						
A.2. Manufactured Gas Production						
Operation						
710 Operation supervision and engineering						
Production Labor and Expenses						
711 Steam expenses.						
712 Other power expenses.						
713 Coke oven expenses.						
714 Producer gas expenses.						
715 Water gas generating expenses.						
716 Oil gas generating expenses.						
717 Liquefied petroleum gas expenses.						
718 Other process production expenses.						
gas fuels						
719 Fuel under coke ovens.						
720 Producer gas fuel.						
721 Water gas generator fuel.						
722 Fuel for oil gas.						
723 Fuel for liquefied petroleum gas process.						
724 Other gas fuels.						
gas raw materials						
725 Coal carbonized in coke ovens.						
726 Oil for water gas.						
727 Oil for oil gas.						
728 Liquefied petroleum gas.						
729 Raw materials for other gas processes.						
730 Residuals expenses.						
731 Residuals produced - Credit.						
732 Purification expenses.						
733 Gas mixing expenses.						
734 Duplicate charges - Credit.						
735 Miscellaneous production expenses.						
736 Rents.						
Maintenance						
740 Maintenance supervision and engineering.						
741 Maintenance of structures and improvements.						
742 Maintenance of production equipment.						
b. natural gas production expenses						
B.1. Natural Gas Production and Gathering						
Operation						
750 Operation supervision and engineering.						
751 Production maps and records.						
752 Gas wells expenses.						
753 Field lines expenses.						
754 Field compressor station expenses.						
755 Field compressor station fuel and power.						
756 Field measuring and regulating station expenses.						
757 Purification expenses.						
758 Gas well royalties.						
759 Other expenses.						
760 Rents.						
Maintenance						
761 Maintenance supervision and engineering.						
762 Maintenance of structures and improvements.						
763 Maintenance of producing gas wells.						
764 Maintenance of field lines.						
765 Maintenance of field compressor station equipment.						
766 Maintenance of field measuring and regulating station equipment.						
767 Maintenance of purification equipment.						
768 Maintenance of drilling and cleaning equipment.						
769 Maintenance of other equipment						
B.2. Products Extraction						
Operation						
770 Operation supervision and engineering.						
771 Operation labor.						
772 Gas shrinkage.						
773 Fuel.						
774 Power.						
775 Materials.						
776 Operation supplies and expenses.						
777 Gas processed by others.						
778 Royalties on products extracted.						
779 Marketing expenses.						
780 Products purchased for resale.						
781 Variation in products inventory.						
782 Extracted products used by the utility - Credit.						
783 Rents.						
Maintenance						
784 Maintenance supervision and engineering.						
785 Maintenance of structures and improvements.						
786 Maintenance of extraction and refining equipment.						

787 Maintenance of pipe lines.						
788 Maintenance of extracted products storage equipment.						
789 Maintenance of compressor equipment.						
790 Maintenance of gas measuring and regulating equipment.						
791 Maintenance of other equipment.						
c. exploration and development expenses						
Operation						
795 Delay rentals.						
796 Nonproductive well drilling.						
797 Abandoned leases.						
798 Other exploration.						
d. other gas supply expenses						
Operation						
800 Natural gas well head purchases.						
800.1 Natural gas well head purchases, intracompany transfers.						
801 Natural gas field line purchases.						
802 Natural gas gasoline plant outlet purchases.						
803 Natural gas transmission line purchases.						
804 Natural gas city gate purchases.	247,457,293	250,078,370	214,502,540	266,160,172	202,359,237	255,180,180
804.1 Liquefied natural gas purchases.						
805 Other gas purchases.	(1,814)	(5,442)				
805.1 Purchased gas cost adjustments.	12,157,352	5,601,002	898,476	(37,730,182)	(4,674,021)	(19,288,831)
806 Exchange gas.						
807 Purchased gas expenses.						
808.1 Gas withdrawn from storage - Debt.	22,932,919	21,687,940	19,408,914	32,607,408	17,913,784	18,407,841
808.2 Gas delivered to storage - Credit.	(18,187,452)	(25,397,528)	(19,279,491)	(35,303,621)	(13,143,711)	(26,476,513)
809.1 Withdrawals of liquefied natural gas held for processing - Debt.						
809.2 Deliveries of natural gas for processing - Credit.						
810 Gas used for compressor station fuel - Credit.						
811 Gas used for products extraction - Credit.	(566,023)	(1,015,361)	(1,448,821)	(699,291)	(297,348)	(1,018,164)
812 Gas used for other utility operations - Credit.						
813 Other gas supply expenses.	2,072,264	2,014,546	1,597,405	1,553,513	1,604,679	1,764,142
2. Natural Gas Storage, Terminaling and Processing Expenses						
a. underground storage expenses						
814 Operation supervision and engineering.	16,127	25,153	15,179	15,735	7,196	4,207
815 Maps and records.						
816 Wells expenses.						
817 Lines expenses.						
818 Compressor station expenses.						
819 Compressor station fuel and power.						
820 Measuring and regulating station expenses.						
821 Purification expenses.						
822 Exploration and development.						
823 Gas losses.						
824 Other expenses.	705,893	819,775	877,951	772,251	805,804	889,434
825 Storage well royalties.						
826 Rents.						
Maintenance						
830 Maintenance supervision and engineering.						
831 Maintenance of structures and improvements.						
832 Maintenance of reservoirs and wells.						
833 Maintenance of lines.						
834 Maintenance of compressor station equipment.						
835 Maintenance of measuring and regulating station equipment.						
836 Maintenance of purification equipment.						
837 Maintenance of other equipment.	804,745	806,732	1,554,613	2,239,715	2,186,040	2,099,183
b. other storage expenses						
Operation						
840 Operation supervision and engineering.						
841 Operation labor and expenses.						
842 Rents.						
842.1 Fuel.						
842.2 Power.						
842.3 Gas losses.						
Maintenance						
843.1 Maintenance supervision and engineering.						
843.2 Maintenance of structures and improvements.						
843.3 Maintenance of gas holders.						
843.4 Maintenance of purification equipment.						
843.5 Maintenance of liquefaction equipment.						
843.6 Maintenance of vaporizing equipment.						
843.7 Maintenance of compressor equipment.						
843.8 Maintenance of measuring and regulating equipment.						
843.9 Maintenance of other equipment.						
c. liquefied natural gas terminaling and processing expenses						
Operation						
844.1 Operation supervision and engineering.						
844.2 LNG processing terminal labor and expenses.						
844.3 Liquefaction processing labor and expenses.						
844.4 LNG transportation labor and expenses.						
844.5 Measuring and regulating labor and expenses.						
844.6 Compressor station labor and expenses.						
844.7 Communication system expenses.						
844.8 System control and load dispatching.						
845.1 Fuel.						
845.2 Power.						
845.3 Rents.						
845.4 Demurrage charges.						
845.5 Wharfage receipts - credit.						
845.6 Processing liquefied or vaporized gas by others.						
846.1 Gas losses.						
846.2 Other expenses.						
Maintenance						
847.1 Maintenance supervision and engineering.						
847.2 Maintenance of structures and improvements.						
847.3 Maintenance of LNG processing terminal equipment.						
847.4 Maintenance of LNG transportation equipment.						
847.5 Maintenance of measuring and regulating equipment.						
847.6 Maintenance of compressor station equipment.						
847.7 Maintenance of communication equipment.						
847.8 Maintenance of other equipment.						
3. Transmission Expenses						
Operation						
850 Operation supervision and engineering.						
851 System control and load dispatching.						
852 Communication system expenses.						
853 Compressor station labor and expenses.						
854 Gas for compressor station fuel.						
855 Other fuel and power for compressor stations.						
856 Mains expenses.						
857 Measuring and regulating station expenses.						
858 Transmission and compression of gas by others.						
859 Other expenses.						
860 Rents.						
Maintenance						
861 Maintenance supervision and engineering.						
862 Maintenance of structures and improvements.						
863 Maintenance of mains.						

864 Maintenance of compressor station equipment.						
865 Maintenance of measuring and regulating station equipment.						
866 Maintenance of communication equipment.						
867 Maintenance of other equipment.						
870 Operation supervision and engineering.	2,394,089	2,517,597	2,133,710	2,571,709	2,566,384	2,415,891
4. Distribution Expenses						
Operation						
871 Distribution load dispatching.						
872 Compressor station labor and expenses.						
873 Compressor station fuel and power (Major only).						
874 Mains and services expenses.	6,223,508	6,848,075	5,760,059	6,006,761	6,767,956	6,634,792
875 Measuring and regulating station expenses - General.	214,642	272,676	195,295	202,120	213,070	194,891
876 Measuring and regulating station expenses - Industrial.	10,564	19,000	22,023	9,837	6,318	3,534
877 Measuring and regulating station expenses - City gate check stations.	137,442	165,259	96,654	79,264	69,259	101,935
878 Meter and house regulator expenses.	1,339,147	810,264	697,101	850,056	905,675	950,976
879 Customer installations expenses.	3,147,738	3,190,311	2,648,771	3,312,750	2,471,877	2,537,313
880 Other expenses.	3,417,541	3,211,115	3,259,800	3,505,475	2,478,227	2,446,991
881 Rents.	61,234	63,758	60,361	52,175	48,470	7,489
Maintenance						
885 Maintenance supervision and engineering.	330,676	291,604	233,303	220,749	102,114	87,244
886 Maintenance of structures and improvements.						
887 Maintenance of mains.	2,564,071	2,646,970	2,356,740	2,283,909	2,472,876	2,234,313
888 Maintenance of compressor station equipment.						
889 Maintenance of measuring and regulating station equipment - General.	485,016	511,713	569,260	606,305	739,213	518,443
890 Maintenance of measuring and regulating station equipment - Industrial.	281,286	992,109	103,774	57,433	55,558	32,523
891 Maintenance of measuring and regulating station equipment - City gate check stations.	102,696	105,065	80,624	129,459	233,429	110,593
892 Maintenance of services.	3,508,248	2,018,175	1,664,336	2,113,144	1,874,030	2,339,342
893 Maintenance of meters and house regulators.	2,491,230	2,542,797	2,143,842	2,623,297	2,966,028	2,967,161
894 Maintenance of other equipment.	432,383	490,277	607,116	414,110	448,151	332,076
900-949 Customer Accounts, Customer Service and Informational, Sales and General and Administrative Expenses.						
5. Customer Accounts Expenses						
Operation						
901 Supervision.	307,187	218,512	139,050	137,648	136,117	158,411
902 Meter reading expenses.	2,334,815	2,264,716	1,910,839	1,771,096	935,192	633,259
903 Customer records and collection expenses.	8,757,532	9,001,055	8,035,197	8,318,773	6,893,675	6,776,120
904 Uncollectible accounts.	2,829,960	2,482,594	1,856,595	191,192	3,283,520	2,506,899
905 Miscellaneous customer accounts expenses.	218,799	222,367	241,665	174,009	134,095	85,653
6. Customer Service and Informational Expenses						
Operation						
907 Supervision.						
908 Customer assistance expenses.	11,349,685	13,677,235	10,689,454	13,934,510	13,354,719	13,842,224
909 Informational and instructional advertising expenses.	1,037,214	981,821	1,180,742	1,239,099	975,808	668,155
910 Miscellaneous customer service and informational expenses.	210,950	297,636	324,966	241,254	295,212	294,807
7. Sales Expenses						
Operation						
911 Supervision.						
912 Demonstrating and selling expenses.	293	345	346	259	260	
913 Advertising expenses.	-	-	1,040	-	550	
914 [Reserved]						
915 [Reserved]						
916 Miscellaneous sales expenses.						
8. Administrative and General Expenses						
Operation						
920 Administrative and general salaries.	13,045,177	12,818,632	10,540,964	10,145,930	11,834,574	13,635,816
921 Office supplies and expenses.	1,701,627	1,662,561	1,899,662	1,870,409	1,807,439	1,778,420
922 Administrative expenses transferred - Credit.	(19,751)	(18,822)	(19,674)	(17,719)	(20,135)	(18,574)
923 Outside services employed.	2,889,143	3,072,504	3,740,550	3,805,281	4,513,246	4,875,649
924 Property insurance.	456,130	429,491	448,289	489,741	572,070	704,375
925 Injuries and damages.	1,284,519	1,257,759	1,607,878	1,613,044	1,575,608	1,848,775
926 Employee pensions and benefits.	591,155	567,728	10,522,259	11,308,297	12,341,599	10,841,938
927 Franchise requirements.					-	
928 Regulatory commission expenses.	2,251,001	2,366,012	1,785,080	1,959,465	1,933,458	2,087,312
929 Duplicate charges - Credit.					-	
930.1 General advertising expenses.					-	5,308
930.2 Miscellaneous general expenses.	1,674,151	1,717,673	1,557,349	1,857,212	2,455,255	1,878,650
931 Rents.	394,123	252,321	165,973	132,525	159,577	185,705
Maintenance						
932 Maintenance of general plant.	4,163,915	4,555,212	4,579,981	4,930,291	5,057,592	5,247,381